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Economic assessment of biogas plants as a flexibility option in future electricity systems

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Markus Lauer

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Dotzauer, M.; Pfeiffer, D.; Lauer, M.; Pohl, M.; Mauky, E. et al. (2019), How to measure flexibility – Performance indicators for demand driven power generation from biogas plants. Renewable Energy 134, 135-146. DOI: 10.1016/j.renene.2018.10.021

Purkus, A.; Gawel, E.; Szarka, N.; Lauer, M.; Lenz, V. et al. (2018), Contributions of flexible power generation from biomass to a secure and cost-effective electricity supply—a review of potentials, incentives and obstacles in Germany. Energy, Sustainability and Society 8, 18. DOI: 10.1186/s13705-018-0157-0

Lauer, M.; Hansen, J.K.; Lamers, P.; Thrän, D. (2018), Making money from waste: The economic viability of producing biogas and biomethane in the Idaho dairy industry. Applied Energy 222, 621-636. DOI: 10.1016/j.apenergy.2018.04.026

Lauer, M.; Thrän, D. (2018), Flexible Biogas in Future Energy Systems—Sleeping Beauty for a Cheaper Power Generation. Energies 11, 761. DOI: 10.3390/en11040761

Lauer, M.; Thrän, D. (2017), Biogas plants and surplus generation: Cost driver or reducer in the future German electricity system? Energy Policy 109, 324–336. DOI: 10.1016/j.enpol.2017.07.016

Lauer, M.; Dotzauer, M.; Hennig, C.; Lehmann, M.; Nebel, E. et al. (2017), Flexible power generation scenarios for biogas plants operated in Germany: impacts on economic viability and GHG emissions. International Journal of Energy Research 41, 63–80. DOI: 10.1002/er.3592

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Leipzig, 17.04.2019 Markus Lauer

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Mit dem zunehmenden Ausbau von fluktuierenden erneuerbaren Energien werden zusätzliche Technologien und/oder Bereitstellungskonzepte im Stromsystem benötigt, die den Ausgleich von Angebot und Nachfrage zu jeder Zeit gewährleisten. Neben Flexibilitätsoptionen wie Stromspeicher oder flexible konventionelle Kraftwerke, können Biogasanlagen eine Technologie zur Systemintegration von fluktuierenden erneuerbaren Energien darstellen. Der zukünftige kostenoptimale Einsatz von Biogasanlagen wurde bisher nicht ausreichend untersucht. Daher sollen die Forschungsfragen beantwortet werden, ob Biogasanlagen eine ökonomisch konkurrenzfähige Flexibilitätsoption darstellen und in welchem Umfang sowie mit welcher Betriebsweise diese zukünftig kostenoptimal eingesetzt werden sollten.

Dazu wurden drei verschiedene Ausbaupfade mit sich unterscheidenden Kapazitäten für Biogasanlagen und weitere erneuerbare Energien zur Zielerreichung der nationalen Zubau-Ziele in Deutschland für den Zeitraum 2016 – 2035 definiert. Mit Hilfe der daraus abgeleiteten Residuallastdaten wurde der Einsatz der Biogasanlagen zur Systemstabilität optimiert. Die entstehenden Werte wurden im Anschluss verwendet, um mit einem nicht-linearen Optimierungsmodell den Einsatz von Flexibilitätsoptionen kostenminimal zu ermitteln. Der reduzierte Bedarf an Flexibilitätsoptionen durch zusätzliche (flexible) Biogasanlagen sowie die verringerte Stromeinspeisung aus anderen erneuerbaren Energien stellen dabei den Nutzen der Biogasanlagen dar. Zusätzliche Kosten entstehen durch die Flexibilisierung von Bestands- als auch durch den Bau und Betrieb von Neuanlagen. Kosten und Nutzen, die mit zusätzlichen Investitionen in flexible Biogasanlagen einhergehen, wurden abschließend in einer Kosten-Nutzen-Analyse gegenübergestellt.

Ein erhöhter Anteil von Biogasanlagen im zukünftigen Stromsystem reduziert die Auslastung von vergleichsweise kostenintensiven Kraftwerken und verringert die Investitionen in Stromspeicher und konventionelle Kraftwerke. Dennoch wird durch die vergleichsweise hohen Kosten von (zusätzlichen) Biogasanlagen in keinem Szenario ein ökonomisch vorteilhaftes Ergebnis erzielt. Die Unwirtschaftlichkeit von Biogasanlagen könnte im Falle eines frühzeitigen Kohleausstiegs signifikant verringert werden. Grundsätzlich sollten Biogasanlagen möglichst flexibel eingesetzt werden, um fluktuierende erneuerbare Energien in das Stromsystem zu integrieren. Ein wirtschaftlicher Betrieb von Biogasanlagen im zukünftigen Stromsystem ist nur möglich, wenn deren Kosten gesenkt und/oder zusätzliche Nutzen in anderen Sektoren und Bereichen generiert werden. Bei einer geringen Zubau-Rate von Neuanlagen wären die geringsten Kostensenkungen notwendig.

Abstract

To reduce the negative impact of climate change, the German government has decided to decrease greenhouse gas emissions in the energy sector through the extension of intermittent renewable energies, inter alia. The power supply from photovoltaic and wind power plants is characterized by intermittency that depends on local weather conditions. To ensure a sufficient power supply, further technologies and/or new concepts are required to balance demand and supply in the energy system with an increasing proportion of renewable energies. In addition storage technologies, the extension of power grids and conventional power plants, biogas plants can be one technological solution. However, the cost-efficient role of biogas plants has not been sufficiently assessed. The main objective of this thesis is to compare the economic feasibility of biogas plants with other flexibility options (namely storage technologies and conventional power plants) for the period of 2016 to 2035 in Germany´s electricity system. From an economic point of view, the cost-efficient future installed capacities and the modes of operation of biogas plants have to be analyzed.

To do so, three biogas extension paths and renewable energy portfolios are defined for the considered period. Hourly residual load data are used to optimize the flexible power generation from biogas plants in all scenarios. The resulting residual load data (including biogas) is used as an input in a non-linear optimization model that simultaneously minimizes the costs of the hourly dispatch and the annual investments in conventional power plants and storage technologies. On the one hand, additional biogas plants in the future electricity system reduce the demand for additional flexibility options and substitute the generation from further renewable energies. On the other hand, the flexibilization of existing biogas plants and the investments in new biogas installations lead to additional costs. Finally, the resulting costs and benefits are quantified in a cost-benefit analysis.

As a result, an increasing proportion of biogas plants reduces the demand for additional storage technologies and conventional power plants. Furthermore, the utilization of (existing) conventional power plants with high marginal costs in the considered period is decreased. However, in all scenarios, the costs of additional biogas plants exceed their benefits for the electricity system. This is why Germany´s electricity system is characterized by a sufficient installed capacity of existing flexibility options. An accelerated phasing-out of lignite- and coal-fired power plants to reach national greenhouse gas reduction target values improves the results of the cost-benefit analysis. The electricity generation from biogas plants should be as flexible as possible. The highest net present values are found in the extension path characterized by a low construction rate of new biogas plants. Nevertheless, compared to the phasing-out of biogas plants, additional biogas plants in Germany´s future electricity system require cost reductions and/or must be accompanied by further benefits in other sectors and areas to ensure economically feasible operation.

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List of Publications

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Article 1

Lauer, M.; Thrän, D. (2017), Biogas plants and surplus generation: Cost driver or reducer in the future German electricity system? Energy Policy, 109, 324–336.
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Article 2

Lauer, M.; Thrän, D. (2018), Flexible Biogas in Future Energy Systems—Sleeping Beauty for a Cheaper Power Generation. Energies 2018, 11, 761. DOI: 10.3390/en11040761

Article 3

Lauer, M.; Leprich U.; Thrän, D. (2020), Economic assessment of flexible power generation from biogas plants in Germany's future electricity system. Renewable Energy 146, 1471-1485.
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List of Acronyms

AICSG	Average Integration Costs of Surplus Generation
B	Base(load)
BECCS	Bio-energy with Carbon Capture and Storage
BU	Back Up
CBA	Cost-benefit Analysis
CCS	Carbon Capture and Storage
CHPU	Combined Heat and Power Unit
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
DSM	Demand Side Management
EEG	Renewable Energy Sources Act
F	Flex (Mode of Operation)
F+	Flex+ (Mode of Operation)
FF	Fully Flexible (Mode of Operation)
flh	(Annual) Full Load Hours
GHG	Greenhouse Gas
IN(C)	Increase
LCOE	Levelized Cost of Electricity
Li	Lithium
O&M	Operation and Maintenance
PQ	Power Quotient
PV	Photovoltaic
REF	Reference Scenario
SF	Semi Flexible (Mode of Operation)
SL	Seasonal (Mode of Operation)

Content

1. Introduction

1.1 Background

The effects of global warming on human life can be felt in increasing global temperatures, rising sea levels and extreme weather events, inter alia, and are based on increasing greenhouse gas (GHG) emissions, such as carbon dioxide, methane and nitrous oxide. GHG emissions are predominantly the result of the combustion of fossil fuels and industrial processes (Pachauri, 2015). The Paris Agreement was signed in December 2015 to reduce the negative impact of climate change and limit the increase of the global temperature to well below two degrees compared to the pre-industrial level (UN, 2015).

Consequently, the German government passed the Climate Action Plan 2050, which describes the national GHG reduction goals, to serve the commitment of the Paris Agreement. The Climate Action Plan 2050 aims to decrease Germany′s GHG emissions by 55% by 2030 and by 80 – 95% by 2050 in comparison to the reference year 1990. In 2016, for the first time in Germany, a sector breakdown of the national GHG reduction goals was conducted; the energy sector, which is connected to the highest absolute GHG emissions, must reduce 61 – 62% by 2030 (BMUB, 2016). In the long term, the energy supply must be based on renewable energies. The Renewable Energy Sources Act (EEG), amended in 2017, specifies extension paths for renewable energies in Germany. In particular, wind and photovoltaic (PV) plants characterized by an intermittent power supply will be the most important power generation technologies in Germany (EEG, 2017). Nevertheless, to ensure a sufficient power supply, further technologies, such as storage technologies or flexible conventional power plants, are needed to balance the demand and supply (Lund et al., 2015).

In addition to gas-fired power plants, dispatchable biogas plants are one technical solution to lower GHG emissions to integrate intermittent renewable energies into the system (Lauer et al., 2017a; Szarka et al., 2013). In 2017, about 30 TWh of electricity were generated by biogas plants in Germany, which corresponds to 13.6% of the renewable energy production (BMWi, 2018). However, the EEG 2017 limits the annual expansion of biogas plants to a maximum of 150 (2017 – 2019) and 200 MW (2020 – 2022), respectively (EEG, 2017). Additional biogas plants are not eligible for feed-in tariffs. This was due to the high costs of subsidizing biogas plants. During the period of 2004 – 2014, the average annual installation of biogas plants amounted to 350 MW per year (Scheftelowitz et al., 2015b). As a result, the installed capacity of biogas plants that are phased out after their operating life of 20 years will be higher than the installation of new plants.

According to EEG (2017), the plant design of new biogas installations must be prepared for flexible power generation; the installed capacity has to be at least two times higher than the rated capacity (the annual average of electricity generation) (§ 44b). Additionally, existing biogas plants can use the premium payment for flexibility (§ 50b), that is, refinancing investments in additional combined heat and power units (CHPU) and/or gas storage capacities. Both components of the installation are options to increase the flexibility of biogas plants.

To summarize, flexible power generation from biogas plants is mandatory for new installations and is linked to financial incentives when biogas plants already exist. However, the dispatchable power generation from biogas plants is one of many technical options to integrate intermittent renewable energies into the energy system. An overview of flexibility options is provided in the following.

1.2 Flexibility Options

In 2018, 38.2% of Germany´s gross electricity consumption was generated by renewable energies (Agora Energiewende, 2019), and intermittent wind and PV plants contributed to almost 70% of renewable electricity generation (AG Energiebilanzen, 2019). In contrast to conventional power plants that are dispatchable, the power supply of wind and PV plants can be described as variable, uncertain and location-specific (Kondziella and Bruckner, 2016). As a result, the electricity generation depends on current weather conditions, which can deviate from the forecast and differ from the place of consumption (Kondziella and Bruckner, 2016). In electricity systems, however, supply and demand have to be matched; consequently, electricity systems require the ability to react to uncertainties regarding the demand and supply (Lund et al., 2015). Ma et al. (2013) have defined flexibility as "the ability of a power system to cope with variability and uncertainty in both generation and demand […] at reasonable cost." To meet the requirements caused by variability when the proportion of intermittent renewable energies in the energy system increases, additional technologies—flexibility options—are needed (Huber et al., 2014). On the one hand, when the electricity supply from renewable energies is low, other technologies must supply the demand. On the other hand, during a time of high renewable energy supply, highly pronounced and individual surplus generation events must be avoided. An increasingly flexible energy supply and demand play a key role in integrating intermittent renewable energies into the electricity system. These reduce the curtailment of intermittent renewable energies and allow a quick response to varying electricity demand as well as electricity supply from wind and PV plants. Furthermore, surplus generation can be used in electrical storage technologies or can be converted into renewable hydrogen or methane (Schill, 2013).

In general, flexibility options can be divided into three main categories (Müller and Brunner, 2015), presented in Table 1:

Table 1: Overview of the classification of flexibility options (adapted from Müller and Brunner [2015]).

<table>
<tr><th>Spatial Shift of Electricity</th><th>Supply-side Flexibility</th><th>Temporal Flexibility</th></tr>
<tr><td rowspan="3">• Expansion or strengthening the power grid
• Import and export</td><td>• Conventional power plants
• Renewable energies (curtailment)
• Dispatchable renewable energies</td><td>• Energy storage</td></tr>
<tr><td colspan="2">Demand-side Management</td></tr>
<tr><td>• Peak clipping
• Valley filling</td><td>• Load shifting</td></tr>
</table>

Spatial shift of electricity:

For different reasons, intermittent renewable energies are installed and concentrated at a distance from the main centers of consumption. Therefore, the expansion and the strengthening of the power grid allows a spatial smoothing and reduces the demand for back-up capacities and storage technologies, respectively (Schaber et al., 2012).

Supply-side flexibility:

Supply-side flexibility is defined as the ability of power generation technologies to adjust their generation on the requirements of the energy system, for example, as caused by the intermittent power supply of wind and PV plants (Lund et al., 2015). An increasing proportion of intermittent renewable energies require conventional power plants that can ramp-up and ramp-down their power generation. However, baseload power plants, such as nuclear and lignite-fired power plants, are characterized by high capital and low variable costs; thus, for economic and technical reasons, they are not constructed for flexible power generation (Nicolosi, 2010). In contrast to baseload power plants, gas-fired power plants are one technological option to ensure a flexible energy system with low GHG emissions (Gonzalez-Salazar et al., 2018).

Temporal flexibility:

Energy storage describes the transformation of energy into a form that allows its reuse at a later time (Aneke and Wang, 2016; Chen et al., 2009). According to Sterner and Stadler (2014), the classification of energy storage technologies depends on the stored forms of energy, for example, mechanical (e.g., pumped-storage plants) or chemical energy storage (e.g., conventional batteries). Depending on their performance characteristics, such as round-trip efficiency, maximum power or capacity and economic parameters, storage technologies are used for the short- to long-term shifting of energy.

Demand-side management (DSM) provides both supply-side and temporal flexibility. In addition to energy efficiency measures and strategic load growth, demand response is a subcategory of DSM (Jabir et al., 2018). Demand response allows temporal flexibility when technologies shift the use of electricity from peak to off-peak hours (Gellings, 2017). This is called *load shifting* and works similarly to energy storage technologies. Meanwhile, *peak clipping* and *valley filling* are part of the supply-side flexibility; the electricity demand is decreased or increased in peak and off-peak hours, respectively (Gellings, 2017).

The flexibilization of existing conventional power plants is the least expensive way to integrate intermittent renewable energies into the energy system (Greiner and Hermann, 2016). When the proportion of renewable energies is higher than 60%, in addition to flexible power supply and demand (e.g., industry), energy storage technologies become more important (Agora Energiewende, 2014). In general, the demand for storage technologies is on the framework conditions considered, such as the expansion and type of selected renewable energies. According to Sterner and Stadler (2014), in a renewable electricity system (beginning with a proportion of 85%), long-term storage technologies are required, e.g., to integrate a high amount of surplus generation. Additional capacities of (intermittent) renewable energies lead to an increased demand for flexibility options. Whereas, the study of VDE and ETG (2012) has calculated the required short-term storage capacities to be between 14 and 26 GW and long-term storage capacities between 18 and 29 GW (discharge capacity) when 80% of Germany´s electricity demand is provided by renewable energies.

1.3 Biogas Plants

Biogas plants are based on anaerobic digestion, which describes the breakdown of organic feedstock by microorganisms who convert it into the main products methane and carbon dioxide in biogas fermenters. About 60% of the produced biogas contains methane and can be used to generate electricity and heat in CHPU. For injection into the natural gas grid, biogas must be upgraded to biomethane, which requires further treatment to be chemically identical to natural gas (Kaltschmitt et al., 2009).

Compared to the energy supply from intermittent renewable energies, biogas is mainly produced by animal manure and energy crops. It can easily be stored and converted to heat as well as electricity when needed (Holm-Nielsen et al., 2009). In general, biogas plants use the energy carrier locally for energy production (electricity and heat) or to upgrade biogas to biomethane that is injected into the natural gas grid. In 2015, about 92% of the electricity from Germany´s biogas was generated locally in CHPU at the biogas plant. The upgrade of biogas to a natural gas substitute was of minor importance[1] (Daniel-Gromke et al., 2017). The extension of Germany´s biogas plants is based on the EEG, which guarantees operators of renewable energy plants a remuneration for each kilowatt hour of electricity fed into the grid

[1] As a consequence, in this thesis, biogas plants do not include the upgrade to biomethane.

for a determined period of time (in general, 20 years). As a result, biogas plants were designed to reach the highest possible full load hours and to maximize annual remuneration (Hochloff and Braun, 2014). Correspondingly, the baseload operation of biogas plants (and conventional power plants) can lead to additional system costs if, for example, intermittent renewable energies must be curtailed due to the baseload generation of renewable and conventional power plants. The basic idea of flexible power generation from biogas plants is that the use of a gas storage unit and/or demand-oriented biogas production allows the temporal separation of biogas production and power generation in the CHPU. Biogas plants should reduce their power generation when the supply from intermittent renewable energies is high and/or the energy demand is low, and they should increase generation in the opposite case.

For flexible power generation, the installed capacity of biogas plants must be significantly higher than the rated capacity, which is defined as the annual average of the electricity generation in kilowatts. According to Lauer et al. (2017a) and the definitions of EEG (2012), the flexibility of biogas plants can be described by the power quotient PQ:

$$PQ = \frac{P_{inst}}{P_{rated}} \tag{1}$$

where P_{inst} is the installed and P_{rated} the rated capacity of the biogas plant.

In principle, there two ways to increase PQ (Figure 1). First, in existing biogas plants, the rated capacity can be decreased by the input reduction of feedstock. In this case, the biogas plant operator tries to save the input of the most expensive feedstock (e.g., maize). The existing CHPU must generate in lower-efficiency partial-load or in start-stop operation. As a result, the biogas plant becomes flexible, and the annual amount of power generation is reduced. A second option is the installation of an additional or larger CHPU that allows the temporary concentration of energy generation; the annual amount of power generation is identical (depending on the efficiency of new CHPU) to the baseload generation.

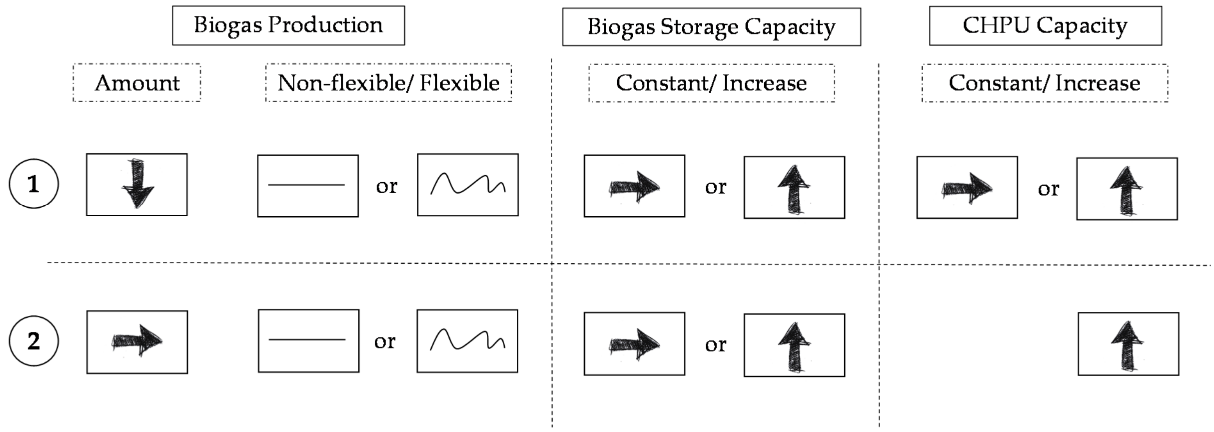

Figure 1: Overview of flexibilization approaches of existing biogas plants. No. 1: Flexible power generation when biogas production is reduced. No. 2: Flexible power generation when biogas production is set as constant.

In mid-2017, about 1.5 GW of the installed capacity of biogas plants were technically adjusted for flexible power generation, corresponding to a share of approximately one-third of Germany´s biogas plant capacity (Daniel-Gromke et al., 2017). According to Scheftelowitz et al. (2018), the average PQ of Germany´s flexibilized biogas plants is two, and the majority of flexibilized biogas plants was characterized by an installed capacity between 501 and 5,000 kW.

To increase the flexibility of biogas plants, a demand-oriented power supply can be implemented through the use of on-farm gas storage capacities and/or by demand-driven biogas production (Hahn et al., 2014). The demand-driven biogas production is based on the control of the biological process through managing the intervals and amount of the feedstock input or the type of feedstock used (Grim et al., 2015; Hahn et al., 2014; Mauky et al., 2017). For example, Mauky et al. (2017) have shown that the intraday biogas production can vary by ± 50% compared to the average. This enables a higher flexibility of power generation. The CHPU's maximum period in nominal load or downtime can be increased to integrate intermittent renewable energies into the system.

1.4 Current State of Science and Knowledge Gap

The role of bioenergy in future energy systems in Europe has been assessed by several studies. For example, Scholz et al. (2017) have calculated the cost of the future European power system, taking into account a varying proportion of intermittent renewable energies. They used the energy system model REMix and found that, due to the high capital costs of biomass (and geothermal power) plants, those technologies were not part of the future renewable energy mixture in all scenarios. Jensen and Skovsgaard (2017) have analyzed the interdependence of the price of CO_2 and biogas capacities in Denmark; high prices of CO_2 led to a significant proportion of biogas in the energy mix and decreased the overall system costs.

In Germany, an increasing number of publications have addressed flexible power generation from bioenergy (especially biogas) plants. Hochloff and Braun (2014) have analyzed flexible power generation from biogas plants under German market conditions and shown that concentrating electricity generation in peak load hours and providing control power generates additional revenues for biogas plants. However, these revenues are not sufficient to refinance investments in additional CHPU and gas storage capacities. The flexibility premium of the EEG is needed to make flexible biogas plants economically feasible. Lauer et al. (2017a) have found similar results, underlining the profitability of flexible power generation from the perspective of biogas operators.

However, the profitability of flexible power generation from biogas plants gives no indication of costs and benefits in the electricity system. The cost of further (flexible) biogas plants and additional investments in enhanced CHPU and biogas storage capacities must be lower than the benefits in the electricity system to become economically feasible from a systemic point of view. Those benefits can be defined as reduced demand for alternative flexibility options (e.g., storage technologies) or other renewable energies (e.g., onshore wind) to fulfill the renewable energy targets of the EEG.

Tafarte et al. (2017) have analyzed the effect of flexible power generation of biomass plants in one of Germany´s transmission systems for the year 2022; they calculated reductions of the residual load fluctuations of about 30% from flexible bioenergy plants when their share of renewable energy production was 23.3% in the year considered. The term "residual load" describes the electricity load minus power generation from renewable energies. Consequently, bioenergy plants can be an important part of Germany´s future flexibility options. However, this study did not include an economic analysis. Holzhammer (2015) has modeled the reduced total system costs in Germany in 2030, when power generation from biogas plants and biomethane CHPU is flexibilized. These results were based on fuel saved and a lower amount of start-stop operations in conventional power plants, inter alia, that cancel out the additional costs of flexible power generation from bioenergy plants. Eltrop et al. (2016) have also shown the total system costs savings in Germany; they considered three varying proportions of renewable energies of the gross electricity consumption (40%, 60% and 80%) and endogenously optimized the installed capacity of biomass plants (the electricity generated by biomass was set as constant). When biomass plants were flexibilized, total system costs were reduced by up to €419 million per year. Based on this analysis, Fleischer (2017) has optimized Germany´s future power plant portfolio for determined renewable energy proportions. As a result, biomass plants reduced annual generation costs in energy systems dominated by renewable energies due to the reduction of investments in other renewable energies, further flexibility options and grid extensions, inter alia.

The above-mentioned studies analyze the impact of flexible bioenergy for a target year or for a determined proportion of (intermittent) renewable energies. Consequently, an analysis that investigates all costs and benefits from flexible bioenergy starting today and continuing until the target system (e.g., a determined proportion of renewable energies) is reached is missing. A comprehensive economic assessment of (flexible) biogas plants in Germany´s future electricity system includes all costs and benefits of the transformation of the electricity system towards renewable energies. The results could be the basis for policy-makers with regard to the future role of (flexible) biogas plants as a flexibility option in the electricity system. In particular, this applies to the future extension paths and modes of operation of biogas plants.

1.5 Objectives

In this thesis, the main research question is defined as follows:

Are biogas plants an economically feasible flexibility option in the future German electricity system compared to other technologies?

This question can be divided into three subordinate research questions:

1) What is the influence of varying future biogas (and other renewable) extension paths and the modes of operation of biogas plants on the residual load in the considered period?
2) What are the impacts of (flexible) power generation from biogas plants on the system costs in Germany´s electricity system?
3) What recommended action can be derived from the economically preferable future extension path and mode of operation of biogas plants?

The flexible power generation from biogas plants in the future German electricity system is assessed economically by modeling their impact on the system costs and via the consideration of a cost-benefit analysis for the period of 2016 – 2035.

This thesis is based on three journal articles, which are already available online. Table 2 shows their link to the defined research questions.

Table 2: Link of the journal articles to the research questions of this thesis and their content.

Journal article	**No.**	**Addressed subordinate research question**	**Content**
Lauer, M., Thrän, D. (2017), Biogas plants and surplus generation: Cost driver or reducer in the future German electricity system? Energy Policy 109, 324–336.	1	1	Design of future extension paths of biogas plants and other renewable energies, analyzing the impact of biogas plants on the residual load curve, development of a new economic approach to assess flexibility options.
Lauer, M., Thrän, D. (2018), Flexible Biogas in Future Energy Systems—Sleeping Beauty for a Cheaper Power Generation. Energies 11, 761.	2	1.2	Model development and calculation of the monetized impact of biogas plants on the electricity system.
Lauer, M., Leprich, U., Thrän, D. (2020), Economic assessment of flexible power generation from biogas plants in Germany´s future electricity system. Renewable Energy 146, 1471-1485.	3	3	Economic assessment of biogas extension paths and modes of operation using a cost-benefit analysis.

Furthermore, the following articles are related to the content of this thesis:

(i) Dotzauer, M.; Pfeiffer, D.; Lauer, M.; Pohl, M.; Mauky, E. et al. (2019), How to measure flexibility – Performance indicators for demand driven power generation from biogas plants. Renewable Energy 134, 135-146.

(ii) Purkus, A.; Gawel, E.; Szarka, N.; Lauer, M.; Lenz, V. et al. (2018), Contributions of flexible power generation from biomass to a secure and cost-effective electricity supply—a review of potentials, incentives and obstacles in Germany. Energy, Sustainability and Society 8, 18.

(iii) Lauer, M.; Hansen, J.K.; Lamers, P.; Thrän, D. (2018), Making money from waste: The economic viability of producing biogas and biomethane in the Idaho dairy industry. Applied Energy 222, 621-636.

2. Methodology

The system perspective and the chosen period of 2016 – 2035 aim to define future biogas scenarios by varying their extension and mode of operation as well as analyzing their impact on the electricity system in Germany.

To answer the above-defined research questions, five steps were conducted (Figure 2):

(i) First, representative days were selected based on the hourly feed-in data from wind and PV plants as well as the electricity consumption in Germany to represent the period of 2016 – 2035 in various optimization models (Section 2.1).

(ii) Second, three biogas extension paths and renewable energy portfolios were defined. In addition, resulting residual load curves (without biogas) were calculated (Section 2.2).

(iii) Third, flexible power generation from biogas plants by a non-linear optimization model was determined (*Model 1*) (Section 2.3).

(iv) Fourth, a non-linear optimization model was developed to analyze the impact of biogas plants on the utilization of existing flexibility options and on the investment in storage technologies and conventional power plants to ensure a sufficient power supply (*Model 2*) (Section 2.4).

(v) Last, the costs and benefits of an increasing proportion of biogas plants in comparison to their phasing-out was assessed with a cost-benefit analysis (Section 2.5).

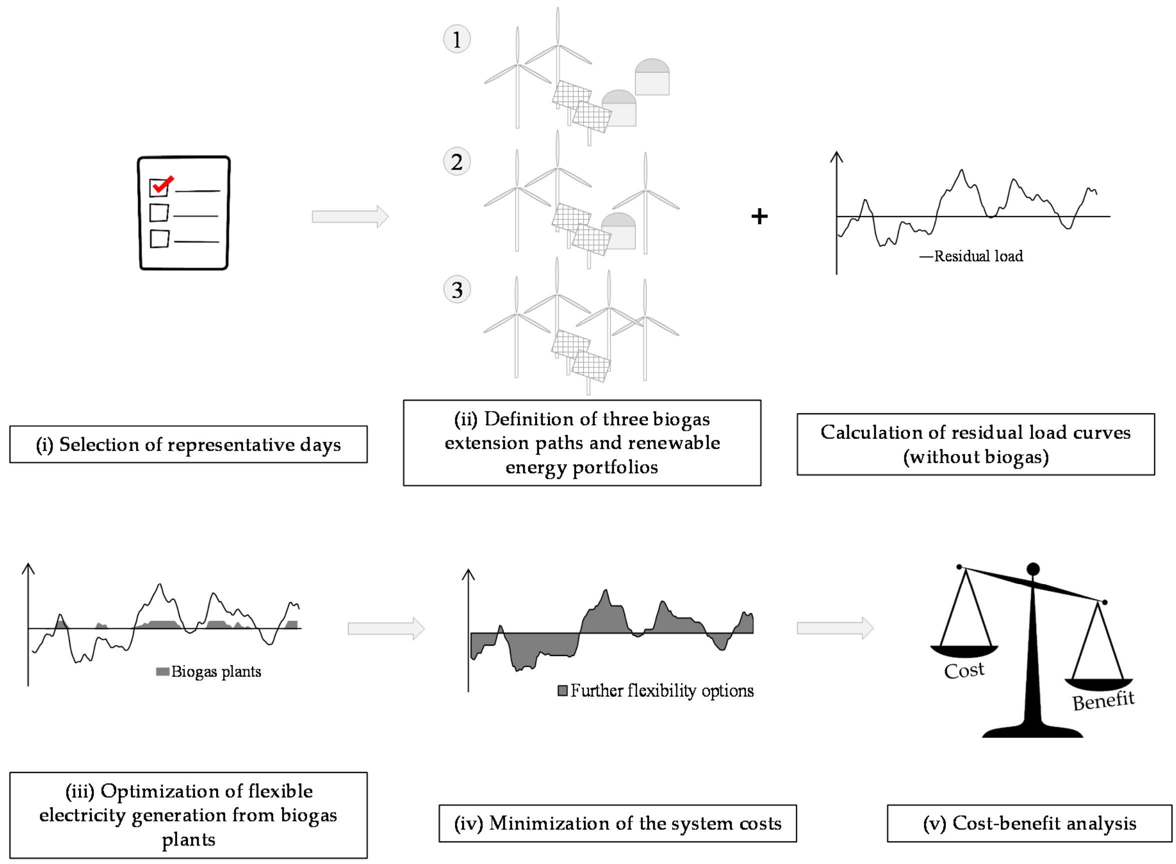

Figure 2: Overview of the methodology (adapted from Lauer and Thrän [2017]).

2.1 Selection of Representative Days

In order to represent the period of 2016 – 2035 in the optimization models, we considered hourly feed-in data from wind and PV and the electricity consumption in Germany based on the year 2015.[2] These data were normalized according to their maximum annual value. Next, we used the clustering algorithm of Nahmmacher et al. (2016) to select and weight representative days. The weighting of representative days allows the extrapolation of the selected days to one year. To use these data for modeling, the period of 20 years was reproduced using four exemplary years (2020, 2025, 2030 and 2035) and seven representative days per year (168 hours), resulting in 672 time slices. A period of 20 years, starting in 2016, was chosen to be identical to the remuneration period of the EEG.

[2] Details of the methodology are provided in Lauer and Thrän (2017).

2.2 Biogas Extension Paths and Residual Load

To reach Germany´s GHG reduction target values in the most cost-efficient manner and to guarantee the security of the country's energy supply, the future capacity and the optimal mode of generation are subject to current political discussions and studies. The goal of the definition of biogas extension paths is to present the range of the current debate. Overall, three biogas extension paths were defined. The proportion of renewable energies in the gross electricity consumption in each biogas extension path was oriented around the target values of the EEG 2014/2017, and the electricity consumption was set to be constant over the period of 2016 – 2035. By 2035, the electricity generation should make up 60% of gross electricity consumption in Germany. Due to the varying electricity generation from biogas plants depending on the defined biogas extension paths, onshore wind power plants were used as an "adjustment screw," resulting in reduced installations when new biogas plants were put into operation (2), (3):

$$W_{onshore,t} = W_{EEG,t} - W_{Renew,t} \tag{2}$$

$$E_{onshore,t} = \frac{(W_{onshore,t} - W_{onshore,t-1})}{flh_{onshore}} \tag{3}$$

where $W_{onshore,t}$ is the annual electricity generated by onshore wind power plants in the year t, $W_{EEG,t}$ is the target value of renewable energy generation defined in the EEG (the proportion of the gross electricity consumption) in the year t, $W_{Renew,t}$ is the sum of the annual electricity generated by all renewable energies with the exception of onshore wind power plants in the year t, $E_{Onshore,t}$ is the extension of onshore wind power plants (installed capacity) in the year t and $flh_{onshore}$ is the annual full load hours of onshore wind power plants.

The extension of PV plants was oriented around data provided by the German transmission system operators (NEP, 2016) and was set to be identical in all biogas extension paths.

The biogas extension paths were as follows:

- *Biogas phase out*: Existing biogas plants start to close after their remuneration period of 20 years; there is no remuneration system for new biogas installations. As a result, all existing biogas plants are phased out in the year 2035 (Figure 3).

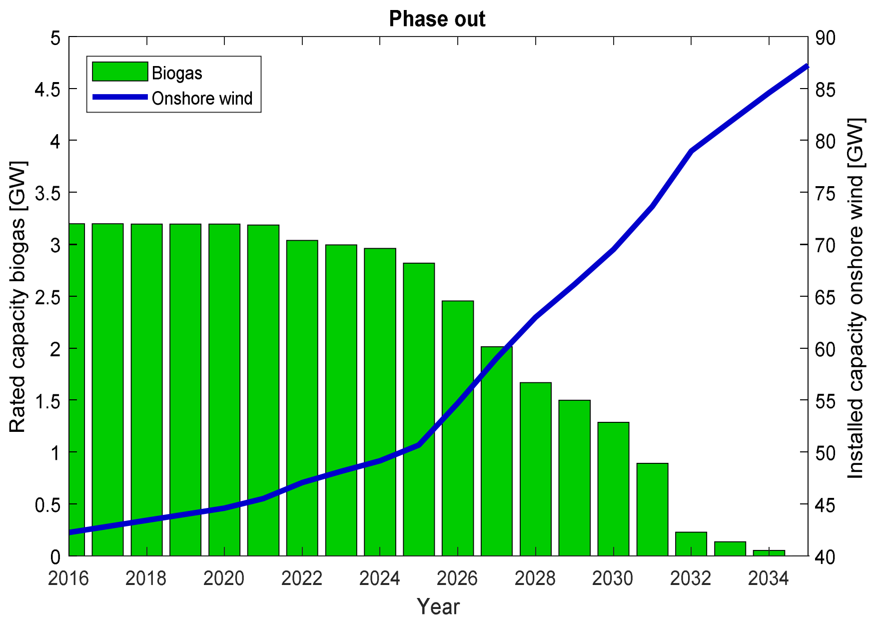

Figure 3: Installed capacities of onshore wind and rated capacities of biogas plants in the biogas extension path *phase out* (adapted from Lauer and Thrän [2018]).

- *Biogas back-up*: According to Repenning et al. (2015) the installed capacity of biogas plants will be reduced to 1,500 MW in 2035 (Figure 4). Taking into account an operating life of 20 years, 75 MW of installed capacity will be put into operation each year. Existing biogas plants will continuously close down.

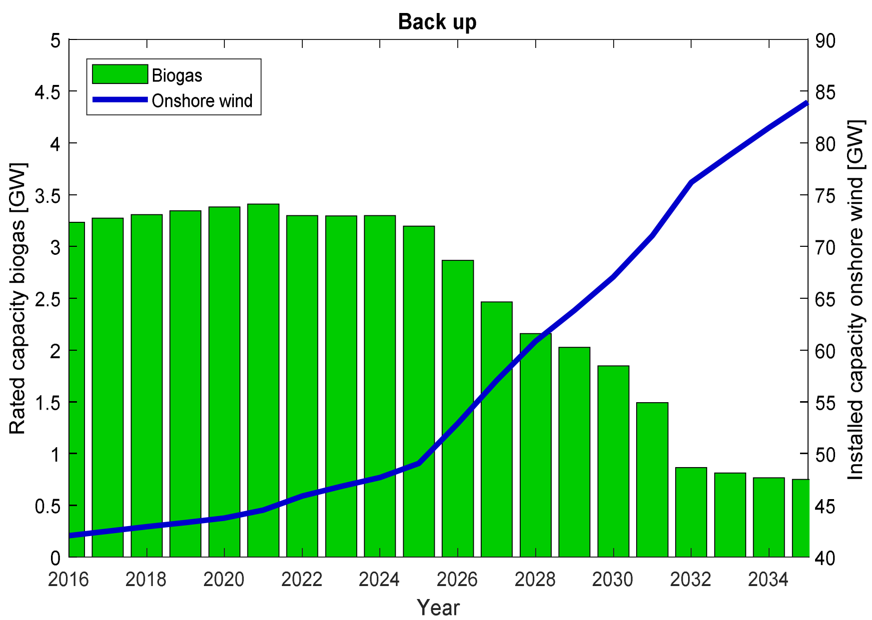

Figure 4: Installed capacities of onshore wind and rated capacities of biogas plants in the biogas extension path *back-up* (adapted from Lauer and Thrän [2018]).

- *Biogas increase*: The German Biogas Association requested an annual net extension path of 100 MW of bioenergy plants in 2016 (Fachverband Biogas, 2016). In this biogas extension path, the annual deconstruction of biogas plants was considered, resulting in annual extension quantities that ensure that the installed capacity increases by 100 MW every year (Figure 5).

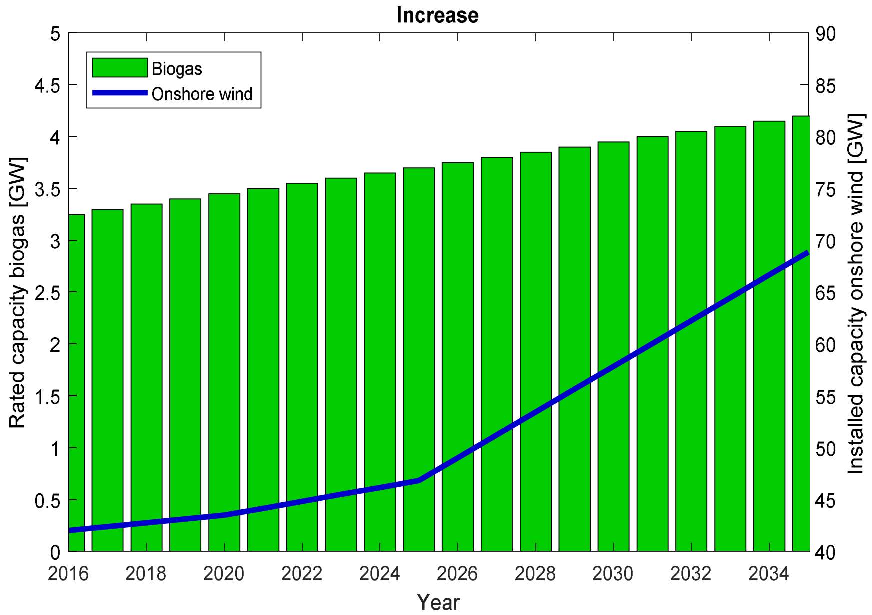

Figure 5: Installed capacities of onshore wind and rated capacities of biogas plants in the biogas extension path *increase* (adapted from (Lauer and Thrän, [2018)]).

Next, depending on the biogas extension path, the resulting installed capacities of the intermittent renewable energies in the exemplary years were multiplied with the normalized hourly feed-in data, which was represented by seven days. In each exemplary year and biogas extension path, the residual load curve (without biogas) was calculated by the difference between electricity consumption and renewable energy supply (without biogas).

2.3 Optimization of Power Generation from Biogas Plants[3]

2.3.1 Biogas Modes of Operation and Scenarios

In addition to the definition of three extension paths of biogas plants, their plant configurations, which resulted in varying modes of operation, were modified and analyzed. To do so, three different modes of operation were defined (Lauer and Thrän, 2018):

i) *Base:* The power generation of biogas plants is set as constant (baseload operation).
ii) *Flex:* Flexible power generation through increased CHPU and gas storage capacities.
iii) *Flex+:* In addition to the *Flex* mode of operation, the biogas production is also flexible. This allows a longer temporary shift of power generation from biogas plants and a longer time in the nominal load.

[3] The model description was adopted from Lauer et al. (2017b).

This thesis considers the scenarios that resulted from biogas extension paths and plant configurations (Table 3). The phasing-out of biogas plants without investments in the flexibilization of existing biogas plants was defined as a reference scenario, which resulted in baseload generation. Extension paths with additional biogas plants were divided into three scenarios in each case: (i) baseload power generation (*Base*), (ii) flexible power generation without demand-oriented biogas production (*Flex*) and (iii) higher flexibility due to the consideration of a demand-oriented biogas production (*Flex+*) of all existing and new biogas plants.

Table 3: Scenarios considered in this thesis, based on biogas extension paths and plant configurations (adapted from Lauer and Thrän [2018]).

Extension Path	**Plant Configuration**	**Scenario**
Biogas phase out	Base (B)	REF
Biogas back-up	Base (B) Flex (F) Flex+ (F+)	BU-B BU-F BU-F+
Biogas increase	Base (B) Flex (F) Flex+ (F+)	INC-B INC-F INC-F+

2.3.2 Description of Model 1[4]

The calculated residual load curves (without biogas) for each biogas extension path were considered to optimize the flexible power generation from biogas plants in the case of the *Flex (F)* and *Flex+ (F+)* modes of operation. When the biogas plants operate in baseload generation, the rated capacity was subtracted from the corresponding residual load curve. Otherwise, a non-linear optimization model (Model 1), which was implemented in MATLAB using the interior-point algorithm (fmincon), was taken into account. The basic idea of this model is that flexible power generation from biogas plants contributes to smoothing the residual load curve, resulting in lower demand for other flexibility options. For example, the installed capacity of storage technologies can be decreased when the amount and frequency of extreme characteristics of the residual load curve are reduced. To do so, the model minimizes the sum of the squared deviations of the hourly residual load values and the generated power from biogas plants at each time t over the period with length T (4). Exogenous model parameters include the hourly residual load values as well as the rated capacity, PQ, annual power generation and the constraints of the flexible biogas production. An overview of sets, indices, parameters and variables considered in the model is given in Lauer et al. (2017b) and in the Appendix (Table A1). As a result, residual load curves (including biogas) for each scenario were used as input data for Model 2.

[4] The model description was adapted from Lauer et al. (2017b).

$$min\, f\left(\{p_t\}_t^T \middle| \{r_t\}_t^T\right) = \sum_t (r_t - p_t)^2 \tag{4}$$

Where p_t is the biogas power generation and r_t is the residual load value in one hour at time t.

Subject to

$$MinB \leq b_t \leq MaxB \tag{5}$$

$$NBC \leq b_{t+1} - b_t \leq PBC \tag{6}$$

$$0 \leq p_t \leq MaxP \tag{7}$$

$$\frac{1}{T}\sum_t^T p_t = RC \tag{8}$$

$$0 \leq s_t \leq SC \tag{9}$$

$$s_t = s_{t-1} + b_t - p_t \tag{10}$$

Biogas plants produce biogas with a specific amount b_t in one hour at time t. The biogas production is either constant, meaning that it is treated as a parameter, or as a variable, which can take values in a specific interval. For our purposes, b_t accepts different values between minimum biogas production (*MinB*) and maximum biogas production (*MaxB*) (5). When the biogas generation b_t is variable, there is a restriction on the hourly biogas change rate (6). To constrain the change, the parameters positive biogas change (*PBC*) and negative biogas change (*NBC*) were taken into account. The power generation from biogas plants can take values between zero and maximum power generation (*MaxP*) (7). To compare all scenarios, the quotient of the sum of the hourly power generation over the period T should be consistent with the rated capacity (*RC*) (8). The variable s_t denotes the gas storage filling level at time t, which is restricted to lie in [0; SC] (9), where *SC* is the storage capacity. In addition, the storage level at time t is fully dependent on the current biogas production, power generation and on the storage level at time $t - 1$ (10).

2.4 Minimization of System Costs

On the basis of the residual load curves in each scenario, Model 2 was used to minimize the system costs depending on the biogas extension paths and modes of operation. The general assumptions of Model 2 are presented in Section 2.4.1, and a detailed description of the Model can be found in Section 2.4.2.

The majority of energy system models are based on (mixed-integer) linear programming (Collins et al., 2017). This is why linear programing is more efficient (Hoffman and Wood, 1976) and reduces the runtime of the model. For example, the analysis of Fleischer (2017) is based on the model E2M2-Bio, which uses linear programming to optimize the composition of flexibility options. In contrast to other studies, we used an alternative non-linear modeling approach that enables us to focus on the time value of money, which becomes necessary when considering a period of 20 years.

2.4.1 Key Assumptions of Model 2

In this thesis, regional aspects of the energy transformation process in Germany were neglected. Consequently, grid bottlenecks were not considered, and the electricity grid was simplified to a “copper plate”. To focus on Germany, the import and export of electricity was not considered. With regard to Müller and Brunner (2015), the range of capital and variable costs of DSM (load shifting) is comparable to energy storage technologies. Likewise, the availability of load shifting is more sensitive to exogenous factors, such as the outside temperature, and the duration of load shifting through DSM is limited to a maximum of 12 hours because the flexible power generation from biogas plants was compared to the following flexibility options:

a) existing conventional power plants and pumped-storage plants
b) new installations of pumped-storage plants
c) new installations of gas-fired power plants
d) new installations of Li-ion batteries

Existing and new conventional power plants are technically represented by the minimum and maximum load and ramping rates per hour.

2.4.2 Description of Model 2[5]

In order to analyze the impact of (flexible) power generation of biogas plants on the systems costs, a non-linear optimization model was developed (Model 2) that simultaneously minimizes the costs of the optimal hourly dispatch and the annual investments in conventional power plants and storage technologies. The results depend on the varying residual load curves that include the (flexible) power generation from biogas plants (Section 2.3). The installed capacities of nuclear, lignite-, coal- and gas-fired power plants ([NEP, 2016], Scenario B 2025/2035) were predetermined exogenously for the period of 2016 – 2035. With regard to the optimal hourly dispatch in each hour and the total cost minimization, the model endogenously optimized additional investments in flexible gas-fired power plants, pumped-storage plants and battery storage technologies (Li-ion) to balance the demand and supply of the residual load curve, including electricity generation from biogas plants. Technical and economic data regarding storage technologies, such as roundtrip efficiency or investments and marginal costs, were also predetermined exogenously.

To focus on the time component of costs and benefits within a period of 20 years, Model 2 discounts all investments and marginal costs by a social discount rate. Furthermore, we considered the hourly dispatch of operational power system models by simplifications as well as the reduction of time slices by representative days and focused on a period of 20 years, which is part of long-term energy system planning models. The model was implemented in MATLAB using the interior-point algorithm (fmincon).

The non-linear optimization model is described by the following equations and inequalities. Equation (11) represents the objective function, and equations (12) to (21) describe the constraints of the model. An overview of sets, indices, parameters and variables considered in Model 2 is presented in the Appendix (Table A1) of journal article 2 (Lauer and Thrän, 2018) in Section 5 of this thesis.

$$\min \sum_{t} \frac{\left(\sum_{exist}(mc_{exist,t} \times \sum_{h} p_{exist,h,t}) + \sum_{new}(mc_{new,t} \times \sum_{h} p_{new,h,t} + cc_{new,t} \times req_{new,t})\right)}{(1+i_{soc})^{t}} \tag{11}$$

Subject to

$$RL_{h,t} - p_{exist,h,t} - p_{new,h,t} \leq 0 \ \forall h, t, exist, new \tag{12}$$

$$req_{stor,t} = cap0_{stor} + \max\{cap0_{stor}; req_{stor,t}\} \ \forall t, stor \tag{13}$$

$$req_{GT,t} = \frac{\max\{req_{GT,t=1}; req_{GT,t}\}}{av_{GT}} \ \forall t$$

[5] The model description was adopted from Lauer and Thrän (2018).

$$minP \leq p_{conv,h,t} \leq maxP \times av_{conv} \ \forall h,t,conv \tag{14}$$

$$|p_{exist,h,t} - p_{exist,h-1,t}| \leq \Delta P \ \forall h,t,exist \tag{15}$$

$$0 \leq fl_{stor,h,t} \leq maxSC_{stor} \ \forall h,t,stor \tag{16}$$

$$fl_{stor,h,t} = fl0_{stor} + fl_{stor,h-1,t} + p_{storin,h,t} \times \eta - p_{storout,h,t} \ \forall h,t,stor \tag{17}$$

$$\sum_h p_{storin,h,t} \times \eta_{stor} = \sum_h p_{storout,h,t} \ \forall t,stor \tag{18}$$

$$p_{storout,h,t} \leq req_{stor,t} \times CF \ \forall h,t,stor \tag{19}$$

$$\sum_h p_{exist,h,t} \times FGHG_{exist,t} + p_{GT,h,t} \times FGHG_{GT,t} + \sum_h p_{renew,h,t} \times FGHG_{renew} \leq maxGHG_t \ \forall t,exist,renew \tag{20}$$

(21)

In the objective function (11), the system costs of existing and newly installed conventional power plants, as well as storage technologies, were minimized for the exemplary years and discounted by a social discount rate i_{soc}. Annual system costs, including capital costs cc_t and marginal costs mc_t, were linearly interpolated between the selected years; with the exception of the years 2016 – 2019, those annual costs were set to be identical to those of the year 2020.

However, these costs were discounted depending on the year *t*. Intermittent renewable energies are characterized by marginal costs close to zero. The residual load $RL_{h,t}$ has to be supplied by the technologies considered in each hour at time *h*, and surplus generation is allowed to occur (12) In addition to existing storage technologies *cap0stor*, the model allows investments in additional capacities $req_{stor,t}$ (13). The installed capacity of gas-fired power plants was endogenously optimized with respect to their average availability av_{conv} (14). Furthermore, the power generation by conventional power plants was constrained by the minimum level of power generation *minP*, the installed capacity *maxP*, the average availability of conventional power plants av_{conv} (15) and the hourly load change rate ΔP (16). In contrast to conventional power plants, the model allows investments in new storage capacities, and the maximum storage capacity is thus exclusively restricted to the extension potential of storage technologies *maxSC* (17). In addition, the overall efficiency η of storage technologies was taken into account by the charging process $p_{STORin,h,t}$ (18). Due to the consideration of weighting factors and representative days, the annual sum of discharged and charged electricity from storage technologies must be identical (19). The maximum discharging rate is defined as the product of the installed capacity $req_{STOR,t}$ and the C-factor *CF* (the maximum discharging power relative to its maximum capacity) (20). According to the German GHG target values in the energy system (BMUB, 2016), the annual sum of conventional and renewable GHG emissions is restricted by the parameter $maxGHG_t$ (21). GHG emissions from renewable and conventional power plants, including biogas plants, were calculated using GHG emission factors *FGHG* (Icha and Kuhs, 2015; Memmler et al., 2014).

2.5 Cost-benefit Analysis

A cost-benefit analysis is used to compare costs and benefits to evaluate the economic feasibility of an examined project or policy decision (Mishan and Quah, 2007). For example, cost-benefit analyses are required for major projects characterized by total costs of at least €50 million in the European Union to receive funding from the European Regional Development Fund (European Commission, 2015). In addition to the economic assessment of investments and decisions, a cost-benefit analysis enables the comparison of varying policy or investment decisions based on their costs and benefits (Mishan and Quah, 2007). One important objective of the cost-benefit analysis is to ensure an "efficient allocation of resources, demonstrating the convenience for society of a particular intervention rather than possible alternatives" (European Commission, 2015). In this thesis, the investments in additional (flexible) biogas plants and in the flexibilization of existing biogas plants in Germany´s future electricity system are analyzed.

Accordingly, we used the cost-benefit analysis to compare the costs and benefits of the above-mentioned biogas extension paths and modes of operation. The biogas extension path *phase out* was defined as a reference in the absence of investments in new or existing biogas installations. Following this approach, the costs and benefits of scenarios with new installations and investments in existing biogas plants (*back-up* and *increase*) in this thesis[6] are as follows (Table 4):

[6] Further benefits of biogas plants are shown in Section 3.2.1.

Table 4: Overview of costs and benefits considered in the cost-benefit analysis of this thesis.

Costs	Benefits
• Additional investments in the flexibilization of existing biogas plants and increased operation and maintenance (O&M) costs. • Capital and operational costs of new (flexible) biogas installations.	• Reduced demand for onshore wind power plants due to the additional electricity generation of biogas plants. • Reduced need for additional flexibility options and decreased utilization of (existing) conventional power plants with high marginal costs.

Details of the cost-benefit analysis are given in Lauer et al. (2020).

3. Results and Discussion

In this section, the main findings and the results of the three journal articles are summarized, and their significance to the analogous (subordinate) research question(s) is discussed.

3.1 Results

The main objective of this thesis was the comparison of the economic feasibility of biogas plants to other flexibility options (namely, storage technologies and conventional power plants) in the period of 2016 – 2035 in Germany´s electricity system. To do so, three varying biogas extension paths and modes of operation were defined and compared. The impact of the biogas extension paths and modes of operation on Germany's future electricity system was calculated by a non-linear optimization model. The resulting costs and benefits were quantified in a cost-benefit analysis. A brief summary of the results linked to the research questions of this thesis is given below, and the results are presented in detail in the corresponding journal articles.

3.1.1 Main Findings

The importance of biogas plants as a flexibility option in Germany´s electricity system depends on the installed capacity and the mode of operation of the installations. Compared to the phasing-out of biogas plants, the installation of new biogas plants and investments in the flexibilization of existing biogas plants in baseload operation led to an improved integration of (intermittent) renewable energies. Biogas plants smoothed the residual load curve that resulted from intermittent renewable energies and reduced the demand for additional flexibility options. Above all, this is because the power generation from biogas plants is dispatchable, and, in our approach, intermittent onshore wind plants are substituted by additional biogas installations. In addition, a higher penetration of (flexible) biogas plants reduced the utilization of existing conventional power plants with high marginal costs and decreased investments in the installation of conventional power plants and storage technologies in the electricity system. However, these benefits are negated by the additional costs of the flexibilization of existing biogas plants and new biogas installations in the period of 2016 – 2035. The current German electricity system has sufficient flexibility options, mainly existing conventional power and pumped-storage plants. These technologies enable system integration within the coming decades for the most part based on the renewable target values of the amendment to the EEG of 2014 and 2017, that is, a maximum proportion of renewable energies of 60% on the gross electricity consumption by 2035. Taking into account all the costs and benefits in the considered period, additional investments in flexibility options (during this period), namely biogas plants, were not economically feasible in all scenarios (Table 5).

The extension paths of renewable energies and the capacities of conventional power plants are key elements of the need for flexibility options. The worst net present values were found when a slow evolution in the German electricity system, driven by a prolonged power generation from (existing) conventional power plants and a decelerated system penetration of renewable energies, was taken into account. However, an accelerated extension of renewable energies and an accelerated reduction of conventional power plant capacities are required to reach national and international GHG reduction target values. This will be necessary to contribute to the international goal of keeping the rise of the average global temperature below two degrees, as the Paris Agreement specifies. An early phasing-out of lignite- and coal-fired power plants improves the cost-efficiency of biogas plants as a flexibility option in the future German electricity system. In this case, biogas plants showed the best results when their power generation was as flexible as possible due to increased gas storage capacities and flexible biogas production (*Flex+*) and in the extension path characterized by a low construction rate of new plants (extension path *back-up*) (Table 5). However, an economically feasible operation of additional biogas plants in Germany´s future electricity system requires cost reductions and/or must be accompanied by further benefits in other sectors and areas that were not taken into account in this thesis.

Table 5: Benefit-cost ratios and net present values in the considered scenarios (in comparison to the reference scenario), non-early and early phasing-out of lignite-and coal fired-power plants (adapted from Lauer et al. [2020]). PQ=2.

	Biogas extension path	**Scenario**	**Benefit-cost ratio**	**Net present value [€ billion]**
Non-early	Increase (INC)	INC-B	0.307	-25.82
		INC-F	0.308	-29.32
		INC-F+	0.311	-29.19
	Back-up (BU)	BU-B	0.332	-5.98
		BU-F	0.324	-8.66
		BU-F+	0.343	-8.41
Early	Increase (INC)	INC-B	0.383	-22.98
		INC-F	0.527	-20.04
		INC-F+	0.528	-19.99
	Back-up (BU)	BU-B	0.634	-3.28
		BU-F	0.718	-3.62
		BU-F+	0.759	-3.09

3.1.2 Findings of the Articles

In **journal article 1**, it is found that the biogas extension path *back up* is preferred to the biogas extension path *increase* from an economic point of view. A higher rate of new biogas installations (*increase*) smoothes the residual load curve and reduces the quantity and frequency of surplus generation events to a greater extent, but the marginal benefit from those additional biogas plants decreases. Furthermore, another important finding was that the flexibilization of existing biogas plants is not cost-efficient. Although the investments in existing plants are low compared to the installation of new ones, in the next decade, there will be no sufficient demand for flexibility in the electricity system. Investments in flexibility options should be better coordinated with the flexibility demand in the future German electricity system.

Journal article 2 confirms the main findings of journal article 1 and analyzes the results in more detail. In addition to the confirmation of a decreasing marginal benefit of a high construction rate of new biogas installations, the power generation from biogas plants should be as flexible as possible. The highest effect on smoothing the residual load curve was achieved when the biogas production was flexible due to the demand-driven biogas production. Based on this effect, the non-linear optimization model mentioned in Section 2.4.2 was used to quantify the impact of biogas plants economically. An increasing proportion of biogas plants influences the utilization of existing conventional power plants and the investments in new flexibility options in the electricity system. Depending on Germany´s GHG reduction target values for the energy system and the objective function of the model (the minimization of the system costs), the utilization of coal-fired power plants was especially reduced. However, in all scenarios, the utilization of lignite-fired power plants in baseload generation increased compared to the reference scenario. Similar results were found for the utilization of nuclear power plants in the year 2020. In addition, flexible power generation enhanced the baseload power supply. Another main finding of the journal article should be highlighted: due to fact that existing conventional power plants in the electricity system are characterized by low marginal costs and by comparably high GHG emissions (e.g., lignite- and coal-fired power plants), the annual GHG emissions were identical in each considered scenario (starting from the year 2025). Looking at the installed capacity of flexibility options, Li-ion batteries and gas turbines were substituted by (flexible) power generation from biogas plants. In all scenarios, pumped-storage plants were installed until the maximum potential was reached.

Journal article 3 presents in detail how saved onshore wind plants contributed the majority of the benefits through an increased proportion of biogas plants and their flexible power generation. Additional opportunity costs in the form of savings in the electricity system, which are characterized by a reduced utilization of existing conventional power plants and lower investments in further flexibility options, are of minor importance. Furthermore, these benefits start to become significant in the year 2025. However, the costs of the flexibilization of existing biogas plants and the installation of new plants cancel out the benefits from an additional proportion of (flexible) biogas plants. Comparing the costs and benefits of additional biogas plants, in all scenarios, the benefit-cost ratio was significantly below one.

As a result, considering all costs and benefits in the period of 2016 – 2035, scenarios characterized by additional investments in existing and new biogas installations are not economically feasible compared to phasing them out.

However, an early phasing-out of conventional power plants, especially lignite- and coal-fired power plants, might improve the cost-efficiency of additional biogas plants in the future electricity system. An accelerated decommissioning of those power plants results in an increasing demand for dispatchable power generation at the beginning of the considered period. Consequently, additional biogas plants reduce the installation of additional flexibility options in the electricity system, resulting in higher benefits of biogas plants through saved opportunity costs. Furthermore, a higher extension of CHPU capacities in biogas plants, combined with an increased maximum load, was analyzed when lignite- and coal-fired power plants were phased out earlier. With the exception of the scenario INC-F+, lower net present values were calculated. Overall, the best results were achieved in the scenario BU-F+, when lignite- and coal-fired power plants (which have a net present value of €-3.09 billion) were phased out earlier. For an economically feasible operation of additional biogas plants, further benefits and/or cost savings are needed.

3.2 Discussion

In this thesis, varying biogas plants and different modes of operation have been economically assessed. It was shown that, compared to their phasing-out, additional (flexible) biogas plants in Germany´s electricity system increase the total system costs when considering the period of 2016 – 2035 and the current power plants. Flexibility in Germany´s future electricity system can also be provided by other flexibility options at a lower cost when the further benefits of biogas plants are not monetized. In this section, the limitations of the study, the study design and the maximum LCOE of new biogas installations for an economically feasible operation are discussed.

3.2.1 Limitations of the Study

The methodology of our study required simplifications of Germany´s electricity system, the model design and the facilitation of existing and new biogas installations. Germany´s electricity grid was simplified to a "copper plate," neglecting regional grid bottlenecks and the curtailment of intermittent renewable energies. In addition, the regional demand for flexibility options to relieve the distribution grid and to balance demand and supply at a subordinate level was not taken into account. Furthermore, the import and export of electricity that can reduce the required amount of storage technologies or flexible power plants was neglected. To summarize, depending on the future design of Germany´s electricity system, the grid extension and the capacities of renewable and conventional power plants, the flexibility demand can vary significantly from our assumptions based on several simplifications.

Regarding further limitations of the study, the design of existing and new biogas installations was simplified. All existing biogas plants in Germany were assigned to clusters of 50 kW installed capacity to calculate the costs of their flexibilization. In addition, new biogas installations were represented by one plant design in the case of baseload or flexible power generation. The plant design of new (flexible) biogas plants was not endogenously optimized in the non-linear optimization model. For these reasons, the resulting potential and costs from (flexible) power generation from biogas plants could deviate because of neglecting the individual plant design of existing installations and the exogenous definition of new biogas plants.

In this thesis, residual load curves for the period of 2016 – 2035 were calculated based on ex-post data from the feed-in of intermittent renewable energies and the electricity consumption in Germany. However, an increasing electricity demand in the sectors of heating and mobility (sector coupling) and the development of advanced renewable energies (e.g., weak wind turbines) will influence Germany´s future residual load. Accordingly, residual load curves that may be subject to changes can lead to flexibility requirements that differ from the results of this study.

The non-linear optimization model optimized the commitment of existing conventional power plants and pumped-storage plants and the investment in three categorized flexibility options. Li-ion batteries, pumped-storage plants and gas-fired power plants represented short-term and long-term storage technologies and conventional power plants, respectively. The monetized impact of biogas plants was calculated based on the technological and economic parameters of the above-mentioned flexibility options. Consequently, the development of new flexibility options or the integration of alternative technologies (e.g., DSM) characterized by varying parameters impacts the benefits from flexible power generation of biogas plants in the electricity system. Furthermore, using exemplary days to represent one year does not enable the consideration of seasonal storage technologies (e.g., power-to-gas).

In addition, we found that the additional benefits of further (flexible) biogas plants are insufficient under Germany´s existing power plants for an economically feasible operation. This can only be achieved if further benefits in the energy system and other areas and/or cost reductions are created. Those positive impacts were not taken into consideration in this study and are described below:

Energy System

- *Power grid extension:* Flexible power generation from biogas plants can reduce the investments in the extension and the improvement of power grids (Trommler et al., 2017). Fleischer (2017) has calculated the cost savings of bioenergy plants in a scenario with a proportion of 80% of renewable energies, amounting to €2.5 billion per year, compared to a non-bioenergy case.

- *Cost savings of conventional power plants:* In addition to the lower utilization of conventional power plants with high marginal costs, Holzhammer (2015) has shown that flexible biogas plants lead to a lower amount of start/stop operations and cost savings. The savings consist of a lower demand for fuel and reduced wear and tear of conventional power plants.
- *Decentralized heat supply:* Heat is an important by-product of biogas plants due to the power generation in CHPU. The excess heat from biogas plants can be used to substitute fossil heat supply and reduce GHG emissions. One option is its use in local heat networks. The share of biogas plants of Germany´s final heat consumption is 1.1% (14 TWh), corresponding to about 8% of the renewable share (BMWi, 2018).
- *Source of carbon for the methanation of hydrogen*: The storage of renewable electricity is an important option to overcome the intermittency of renewable energies. The conversion of electrical energy into chemical energy, such as hydrogen or methane, is characterized by a high storage capacity and allows bridging longer periods of a lower supply from intermittent renewable energies (Sterner and Stadler, 2014). If hydrogen is converted to methane, the natural gas grid can be used to store and transport renewable energy (Schaaf et al., 2014). Biogas plants can be a sustainable source of carbon dioxide for the methanation of hydrogen (Dotzauer et al., 2018).

Environmental/climatic Benefits

- *Reduction of agricultural GHG emissions:* Biogas plants reduce agricultural GHG emissions through improved manure management. In Germany, more than 0.75 kg of CO_2e of GHG emissions per kWh of manure-based biogas plants can be reduced due to this improved management (Oehmichen and Thrän, 2017).
- *Substitution of inorganic fertilizer:* The digestate of biogas plants can be used as a fertilizer and reduces the energy-demanding production and use of inorganic fertilizers in agriculture (Arthurson, 2009).
- *Reduction of GHG emissions and air pollution in the heating sector:* The decentralized use of heat from bioenergy plants substitutes fossil heat production and reduces the corresponding air pollution (Kampman et al., 2016).

Economic Benefits

- *Added value in rural regions:* Hirschl et al. (2011) have shown that the installation and operation of a biogas plant in Baden-Wuerttemberg (a state in Germany) with an installed capacity of 500 kW is related to an added value of more than €500,000 and generates about 11 jobs per plant. Furthermore, biogas plants increase the income of farmers (Lauer et al., 2018).

Other Benefits

- *Source of carbon dioxide for bio-energy with carbon capture and storage:* Bio-energy with carbon capture and storage (BECCS) is an important technology option to meet ambitious GHG reduction target values through the generation of negative emissions. Due to the low costs of BECCS, it will be seen as a central measure to fulfill international climate goals (Azar et al., 2010).

- *Reduction of odor and pathogens:* The use of manure in anaerobic digestion plants reduces odor emissions. Pain et al. (1990) have found that odor emissions of pig slurry were reduced by 70-80%. Furthermore, anaerobic digestion removes pathogens in manure. For example, Côté et al. (2006) have demonstrated decreasing populations of *E. coli* of up to 100% through anaerobic digestion.

3.2.2 Study Design[7]

In this thesis, we focused on the energy transition pathways of Germany's biogas plants. An alternative approach might be the so-called *greenfield approach* of optimizing power plants without considering the existing legal framework and power plants (e.g., the study by Fleischer [2017]). On the one hand, the advantage of our approach is that the dynamic development of decommissioning existing conventional power plants and increasing renewable energies can be analyzed in more detail. This also allows us to identify an advantageous time for investments in flexibility options, such as storage technologies or biogas plants. From the perspective of policymakers, decisions on the future design of renewable energy systems and cost-efficient policy choices must take into account the currently installed capacities of power plants and legal frameworks. On the other hand, the greenfield approach ensures more degrees of freedom to optimize the future energy system. This might be a template for changing current frameworks. In summary, we calculated benchmarks for an economically feasible operation of (flexible) biogas plants in future electricity systems while taking existing frameworks into account. Cost-efficient energy/electricity systems are defined in other studies.

In contrast to the results of this analysis, the study by Fleischer (2017) used a greenfield approach and calculated lower annual generation costs in Germany's electricity system when its predominantly decarbonized renewable energies and bioenergy plants were included. However, Fleischer (2017) optimized Germany's power plant portfolio with regard to varying proportions of renewable energies without taking existing conventional power plants into consideration. Consequently, the optimization of the power plant portfolio in the target system was based on the annualized costs of power plants and the potentials of their energy carriers, among other factors. By concentrating on the target system and not considering existing power plants, biomass plants represent a way to reduce annual generation costs in renewable energy systems. However, our study took Germany's current power plant portfolio and the net present value of the total system costs for the period under consideration into account. This is why we did not calculate the cost-efficient impact of additional biogas plants on total system costs.

[7] The discussion of the study design is adapted from Lauer et al. (2020).

3.2.3 Maximum LCOE of New Biogas Installations

To compare the competitiveness of energy generation technologies, the methodology of the levelized cost of electricity (LCOE) is often used in the literature (e.g., (Lazard, 2017)). The LCOE "takes into account the lifetime energy production and lifetime costs associated with a system" (Darling et al., 2011). This is used as a benchmark to assess the economic viability of energy generation technologies (Allan et al., 2011). Intermittent renewable energies are connected with a significantly lower LCOE than dispatchable renewable plants, such as biogas plants (Table 6). In addition, the cost reduction potential of intermittent renewable energies, especially from PV plants, is more pronounced.

Table 6: Current and future LCOE of renewable energies in Germany.

Technology	**LCOE 2018** **[$€_{2018}$ MWh^{-1}]**	**LCOE 2035** **[$€_{2018}$ MWh^{-1}]**	**Source**
Intermittent renewable energies			
PV	37.1 – 115.4	21.6 – 67.1	(Kost et al., 2018)
Onshore wind	39.9 – 82.3	34.9 – 70.9	
Offshore wind	74.9 – 137.9	56.7 – 100.7	
Dispatchable renewable energies			
Biogas	101.4 – 237.4[8]		(Hoffstede et al., 2018; Kost et al., 2018; Kost et al., 2013)

Deviating from the methodology of the LCOE, in this study we showed that the benefits of dispatchable power generation from biogas can be monetized in Germany´s future electricity system. In addition to the costs of biogas plants resulting in the LCOE, the benefits consist of a reduced demand for intermittent renewable energies, further flexibility options and the lower utilization of (existing) conventional power plants with high marginal costs. Figure *6* presents the annual benefits from biogas plants in the exemplary years 2020, 2025, 2030 and 2035. The relative benefits were calculated up to 119.4 € MWh^{-1} in the *Flex+* mode of operation and the year 2035 (Figure 6), when lignite- and coal-fired power plants are phased out earlier.

[8] The upper value was calculated by considering an inflation rate of 2% (study from 2013).

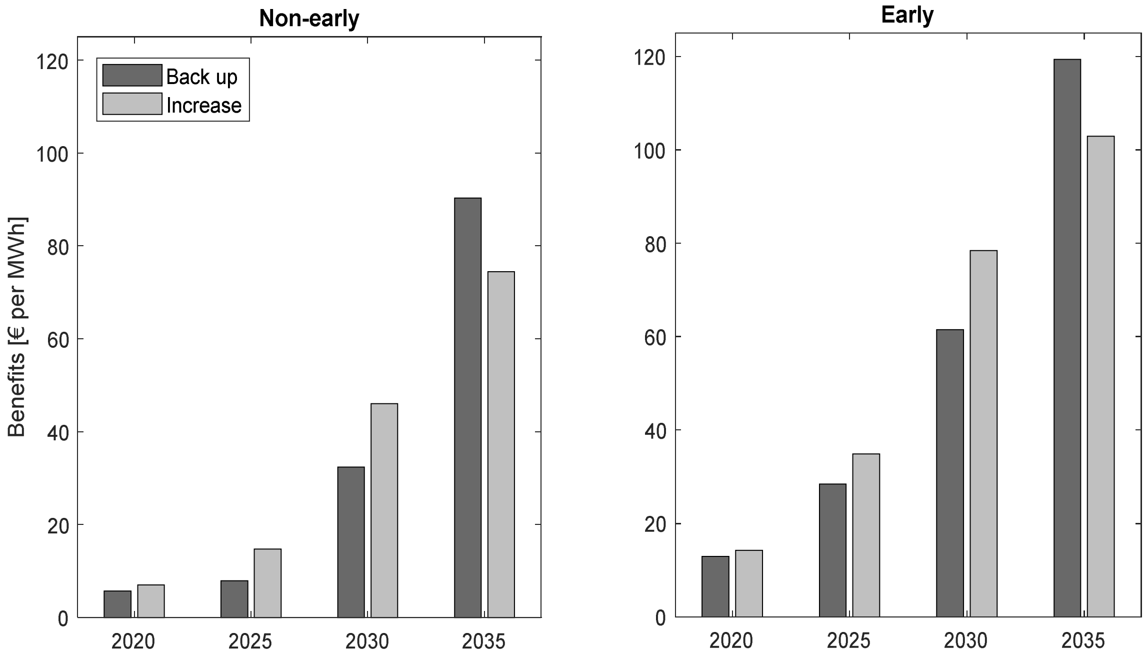

Figure 6: Benefits per MWh of biogas plants consisting of additional saved opportunity costs and saved investments in onshore wind power plants in the *Flex+* mode of operation in non-early (left figure) and early phasing-out of lignite- and coal-fired power plants (right figure).

The benefits of biogas plants can be used to calculate the maximum LCOE that allows operations to be economically feasible in Germany´s future electricity system. The highest maximum LCOE was found in an early phasing-out of lignite- and coal-fired power plants in the scenario BU-F+. A maximum LCOE of 128.3 € MWh^{-1} was calculated when these plants are put into operation in 2018 (Lauer et al., 2020). However, the amendment to the EEG 2017 limits the market premium of new biogas installations to 147.3 € MWh^{-1} in 2018. The current maximum remuneration of biogas plants in Germany is above the determined threshold that allows an economically feasible operation in the future electricity system (Figure 7). However, the current funding is not sufficient to encourage the construction of new biogas plants in Germany. In 2016, only a few biogas plants with an installed capacity higher than 75 kW were installed (Daniel-Gromke et al., 2018). As a result, the LCOE of biogas plants must be reduced to become cost-efficient compared to other flexibility options in the electricity system. Possible strategies for the implementation of reductions in capital and marginal costs are the optimization of existing biogas plants and a focus on cost-efficient waste and residual materials as feedstock. Costs can be reduced when the lifetime of existing biogas plants is extended due to new investments in the installation that are lower than the investments in new biogas installations (Scheftelowitz et al., 2015a).

In addition to the cost reductions of biogas plants, the varying future costs of onshore wind power plants or other flexibility options influence the maximum LCOE of new biogas installations that allows operations to be economically feasible (Figure 7).

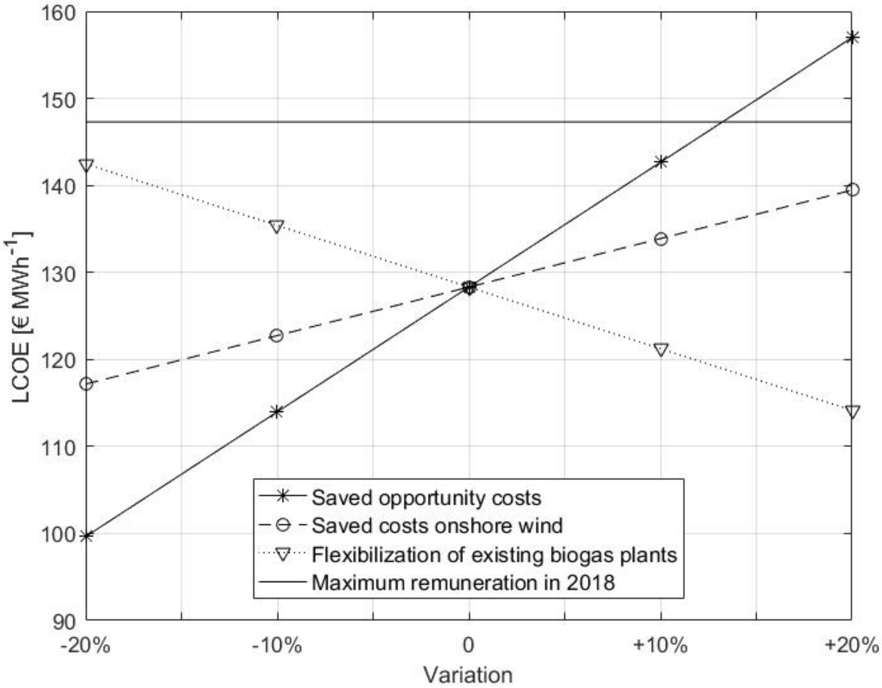

Figure 7: Maximum LCOE of new biogas installations that allows operations to be economically feasible in the scenario BU-F+ and an early phasing-out of lignite- and coal-fired power plants. The commissioning year is 2018.

4. Conclusion and Outlook

The economic feasibility of flexible power generation from biogas plants has been economically assessed by comparison to existing conventional power plants, storage technologies and new gas-fired power plants. Varying biogas extension paths and modes of operation were analyzed in terms of costs and benefits in Germany´s electricity system for the period of 2016 – 2035. Focusing on the electricity system, additional installations of new biogas plants are not economically feasible when no cost reductions and/or further benefits are realized in other sectors and areas. An increasing demand for flexibility in an electricity system characterized by a higher proportion of intermittent renewable energies can be provided more cost-efficiently by conventional power plants and storage technologies.

Additional biogas plants in Germany´s future electricity system reduce the investments in further flexibility options, such as gas-fired power plants and storage technologies. The lowest demands for additional flexibility options are found when the proportion and flexibility of biogas plants were the highest. Flexible power generation especially competes with coal-fired plants characterized by comparably high GHG emissions and marginal costs in the medium-term. Consequently, flexible biogas plants reduce the utilization of coal-fired power plants, but their flexible power supply leads to a higher utilization of conventional baseload power plants, namely nuclear and lignite power plants.

Taking the results of the cost-benefit analysis into account, the best economic results are achieved in the biogas extension path *back-up* with a reduced rated capacity of 750 MW in 2035. A lower rate of new biogas construction leads to higher benefit-cost ratios and net present values in the scenarios considered. The relative saved opportunity costs per MWh of biogas plants in the extension path *back-up* were significantly higher than in the extension path *increase*. The additional benefits in the extension path with a rated capacity of about 4,200 MW in 2035 (*increase*) are canceled out by their resulting costs.

Focusing on the mode of operation, the highest benefit-cost ratios and net present values are calculated in the *Flex+* mode of operation by combining flexible power generation through increased CHPU and gas storage capacities and flexible biogas production. When the phasing-out of lignite- and coal-fired power plants is decelerated, the benefits from flexible power generation are low, and the additional investments in the flexibilization of existing and new biogas installations become inadvisable.

The economic feasibility of biogas plants as a flexibility option strongly depends on the existing power plants in Germany. The results of this thesis indicate that there is currently a low demand for additional flexibility options in Germany´s electricity system. As a result, without an accelerated phasing-out of lignite- and coal-fired power plants, the demand for additional flexibility options decreases. Consequently, biogas extension paths and modes of operation must be better coordinated with the flexibility demand in the electricity system. Additional flexible biogas plants are more advantageous when conventional power plants are phased out earlier.

Compared to the phasing-out of biogas plants, all scenarios with additional biogas plants in Germany´s future electricity system achieved no positive net present values. Nevertheless, taking the further benefits of biogas plants into account, the operation of additional biogas plants can be economically feasible. Depending on the scenario considered, all biogas plants must generate at least annual additional benefits of about €0.2 billion[9] (scenario *BU-F+*, early phasing-out). Further benefits are lower demands for power grid extension or decreased agricultural GHG emissions due to the improved manure management, inter alia.

For further research, three main topics can be defined:

i) non-linear optimization model

Due to the use of a non-linear optimization model, some simplifications had to be conducted to reduce its runtime and complexity. One example is the neglect of the import and export of electricity in Europe. To improve the significance of the results, our methodology should be transferred to advanced energy system models. This would enable the consideration of spatial aspects of the energy system transformation, such as the demand for power grid extension in Germany. In addition, the extension paths and designs of (flexible) biogas plants are defined exogenously for the non-linear optimization model. A further development of the model would include their endogenous optimization.

ii) cost-benefit analysis

As shown in Section 3.2.1, biogas plants create further benefits in the energy system and other areas. A cost-benefit analysis that includes these monetized benefits would enable a more comprehensive economic assessment of biogas plants in the future.

iii) method comparison

Fleischer (2017) used the so-called greenfield approach to optimize the future power plant portfolio in an energy system dominated by renewable energies without the consideration of existing legal frameworks and power plants. In this case, bioenergy plants can be cost-efficient when all power plants are optimized and existing power plants are neglected. Consequently, the methodology and results of both studies should be analyzed to derive improved recommendations for political decision-makers.

Based on the results of this thesis, a proportion of flexible biogas plants should be maintained to develop biogas technology. The economic feasibility of biogas plants in the electricity system is based on varying framework conditions (e.g., extension paths of biogas plants, costs of other flexibility options) that can be subject to changes. Therefore, a reassessment of biogas plants as a flexibility option in the mid-term is required to avoid path dependency due to irreversible decisions.

[9] This corresponds to maximum further benefits of 277 € kW^{-1} of rated capacity in the 2035 in scenario BU-F +, early phasing-out.

5. Articles

Article 1

Biogas plants and surplus generation: Cost driver or reducer in the future German electricity system?

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Biogas plants and surplus generation: Cost driver or reducer in the future German electricity system?

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ABSTRACT

The proportion of (intermittent) renewable energy in the German electricity system is set to continuously increase over the next decades. This brings along with it the challenge of balancing demand and supply. For this paper, we analyzed the cost efficiency of reducing surplus generation to reduce greenhouse gas emissions in the German electricity system for the period of 2016–2035 through (flexible) biogas plants, taking into consideration different biogas extension paths and modes of operation. We assessed flexible power generation in biogas plants using a quotient of remuneration and surplus generation called the average integration costs of surplus generation (AICSG). We defined the AICSG, which can be interpreted as a new approach to assess and to compare the cost efficiency of flexibility options. Increasing the capacities of flexible biogas plants decreases future surplus generation by up to 35% compared to if these installments were phased out. The best AICSG value was generated in a scenario that had a low rate of constructing new biogas plants. In conclusion, the system integration of intermittent renewable energies requires further technologies that result in additional costs. Therefore, biogas plants are one option for improving the system integration of intermittent renewable energies.

1. Introduction

The Paris Agreement, signed in December 2015, emphasizes the international need to reduce greenhouse gas (GHG) emissions and to halt the increase in average global temperatures (UN, 2015). In order to mitigate negative impacts on climate change, the German government's energy concept aims to reduce GHG emissions by at least 80% by 2050 (BMWi, 2012). As a consequence, and in accordance with the Renewable Energy Act (EEG) (i) the gross electricity consumption should be significantly reduced and (ii) the proportion of renewable energy in the electricity sector should make up 40–45% of gross electricity consumption by 2025 and 55–60% by 2035 (BMWi, 2014). In 2015, 31.6% of electricity was generated from renewable resources and the largest proportion of renewable electricity production came from onshore wind, biomass (especially biogas) and photovoltaics (PV) (BMWi, 2016a). According to (BMWi, 2014) and (NEP, 2016) the future development of renewable energy focuses on renewable power generation technologies with the lowest levelized cost of electricity (LCOE). These are currently onshore wind and PV. The LCOE is defined as the sum of fixed and variable costs [€] of a power generation technology over its full life cycle divided by the electricity that is generated [MWh] (Ueckerdt et al., 2013). This measure was developed after an intensive debate on household electricity prices in Germany (WSJ, 2014). In order to slow down the rise in electricity prices, EEG reforms limited the expansion of biomass plants, including all biomass techniques based on solid, liquid and gaseous biofuels (BMWi, 2014). Beyond 2020, the future role of biogas plants is being currently discussed in Germany, e.g. in (BMWi, 2016b). Without the consideration of the phase out of existing biogas plants, the 2017 EEG limited the expansion to a maximum of 150 MW per year for the period of 2017–2019 (BMWi, 2017); between 2004 and 2014 the average installation of biogas plants was about 350 MW per year (Scheftelowitz et al., 2015). This means that the maximum expansion of new biogas plants is in place and that existing plants do not have a clear perspective at the end of their remuneration period (from around 2025). As a consequence, the supply of new plants will not be sufficient, in other words, the installed capacity will go down. In 2014, over 7800 biogas plants with an installed capacity of 4500 MW generated around 27.6 TWh of electricity in Germany (Scheftelowitz et al., 2015). When it comes to a reduction in the electricity generated by biomass plants, this gap has to be filled by additional renewable energies to reach the targeted percentage of renewables. The draft of the 2017 EEG clearly shows that onshore wind, which has the lowest LCOE, is how the government plans to compensate for this

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gap (BMWi, 2016c). Electricity production from wind and PV is intermittent and depends on local weather conditions. This increased proportion of intermittent renewable energies brings with it the challenge of balancing demand and supply (IEA, 2011). This requires further technologies to ensure there is a sufficient power supply. These include flexible power plants, demand side management (DSM), storage technologies and grid extension (Alizadeh et al., 2016). The integration of intermittent renewable energies is also accompanied by additional costs (e.g. DeCarolis and Keith, 2005; Hirth et al., 2015). Flexible power generation from biogas offers the possibility of flexible as well as controllable electricity generation (Szarka et al., 2013) and may therefore reduce electricity system transformation costs. One example is reducing surplus generation events when the supply of (intermittent) renewable energies exceeds current electricity demand.

Evaluating the cost of the transformation towards a renewable energy system is the topic of an increasing number of publications. (DeCarolis and Keith, 2005) show that the LCOE of wind power generation does not represent the effective cost of wind because, due to other grid operations, the cost of intermittency also has to be taken into account. (Ueckerdt et al., 2013) define a new concept to assess the total cost of integrating intermittent renewable energy into the energy system. This is called system LCOE. They argue that the LCOE overestimates the economic efficiency of energy systems with a high penetration of intermittent renewable energies. System LCOE also includes the costs of variability, thus the integration costs of wind can equal the generation costs of wind power (Ueckerdt et al., 2013). (Hirth et al., 2015) define the integration cost of wind as the reduction in market value caused by the variability of renewable energies and the interaction with the rest of the (inflexible) energy system. Whereas, due to external effects, (Zipp, 2016) argues that hourly whole sale prices do not express the real value of the system integration of intermittent renewable energies. As a consequence, integration costs are not negligible for policymaking and for calculating the future costs of system transformation.

(Brouwer et al., 2016) find that increasing the percentage of renewable energies in the western European power system (in 2050) will increase overall system costs. Four options can reduce the integration costs of renewable energies at a higher level: demand response, natural gas-fired plants with carbon capture and storage (CCS), grid extension, and curtailment. (Batalla-Bejerano and Trujillo-Baute, 2016) estimate the cost of balancing service as a consequence of intermittent renewable energies making up an increasing proportion of the Spanish energy system. Due to the geographic location of Spain and the low cross-border interconnection capacity associated with this, flexible power generation from combined cycle plants is the most competitive flexibility option compared to other conventional plants. (Becker et al., 2015) determine the optimal combination of PV and wind for the USA to minimize backup energy requirements. By reducing surplus generation through the optimal mix of wind and PV, they demonstrate that a mixed portfolio of renewables becomes economically feasible with regard to total costs instead of choosing one technology with the lowest generation costs. A similar case study was done for China by (Huber and Weissbart, 2015). To summarize, (Papaefthymiou and Dragoon, 2016) emphasize that diversifying renewable energies leads to a reduction in variability and a cost-optimal system integration.

However, the consideration of the optimal mix of renewable energies often neglects biomass and biogas plants as a way of reducing the total costs of integrating intermittent renewable energies into the system. (Schill, 2014) calculates residual load, surplus generation and storage demand for Germany in 2022, 2032 and 2050. Surplus generation appears in 5% of all hours of the year in 2032 when biomass generation is flexible and thermal must-run capacities are removed. However, inflexible biomass generation and a thermal must-run capacity of 20 GW increase this value to 40%. (Tafarte et al., 2015) model power generation from flexible biogas and solid biomass plants to minimize the residual load variance on a regional scale in Germany. Compared to inflexible systems, the daily variance in the residual load is reduced by at least 50% due to the flexibilization of biomass plants. (Holzhammer, 2015) compares the additional costs of flexibilizing biogas plants in Germany with the saved costs of conventional power plants for flexible power generation in 2030. Biogas plants can reduce total costs in the energy system by lowering the amount of fuel and the start-stop operation of conventional power plants.

The above-mentioned studies reflect the fact that the LCOE does not identify the total costs of integrating intermittent renewable energies. In order to assess total costs of renewable energy integration, several factors should be incorporated, such as the share of renewable energies, the combination of diverse technologies and the consideration of different options for balancing supply and demand. Additional costs arise from other flexibility requirements in the form of investments in higher interconnection capacities, (conventional) flexible power plants, DSM or storage technologies. With regard to the cost-efficient transformation of the energy system, the future role of (flexible) biogas plants has yet to be adequately assessed. The present analysis intends to fill this gap by using different extension paths that have a lower as well as a higher proportion of (flexible) electricity generated from biogas plants in their renewable generation portfolios.

In this paper, we assess the cost efficiency of surplus generation reduction by biogas plants depending on three extension paths varying the installed capacity, electricity amount and mode of operation of biogas plants in Germany for the period 2016–2035. Our approach can be used to assess and compare the cost-efficiency of flexibility options.

The objectives can be defined as follows:

i. To describe options for the installed capacity of biogas with different extension paths by estimating the ongoing transition of the German energy system towards renewables; considering the transition pathways formulated in the EEG;
ii. To calculate residual load and surplus generation in a context of decrease of gross electricity consumption for the period of 2016 – 2035 for the different biogas extension paths;
iii. To optimize flexible electricity generation from biogas plants to reduce surplus generation; through: three different modes of biogas operation and
 a. by considering existing flexible and non-flexible biogas plants;
iv. To consider total premiums[1] and to economically assess the scenarios by using the average integration costs of surplus generation.

2. Methodology

According to the set objectives, we defined three biogas extension paths and future capacities of other renewable energies (Section 2.1), calculated surplus generation and residual load for the period of 2016–2035 (Section 2.2), optimized flexible power generation from biogas plants (Section 2.3) and assessed the scenarios by considering total premiums and by using the average integration costs of surplus generation (Section 2.4). The methodology is also shown in Fig. 1.

2.1. *Defining three biogas extension paths and the future capacities of other renewable energies*

In order to reach the target values of the EEG, which are oriented towards a percentage of renewable energies in gross electricity consumption, the lower generation of electricity from biogas plants has to be compensated for by other renewable energies. Based on current debates in Germany, onshore wind is used as a “adjustment screw” to fulfil the goals

[1] Total premiums are part of the German remuneration system for renewable energies which is described in Section 2.4.

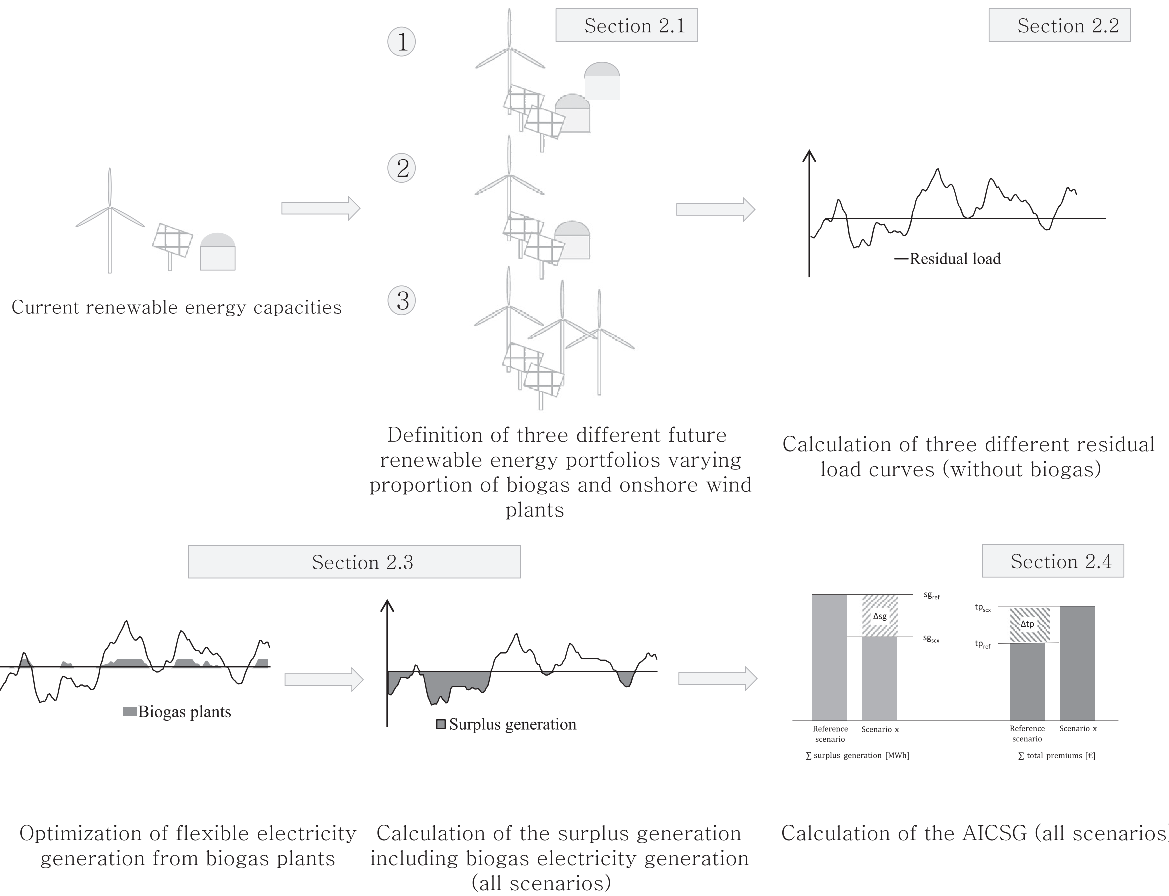

Fig. 1. Overview of the methodology.

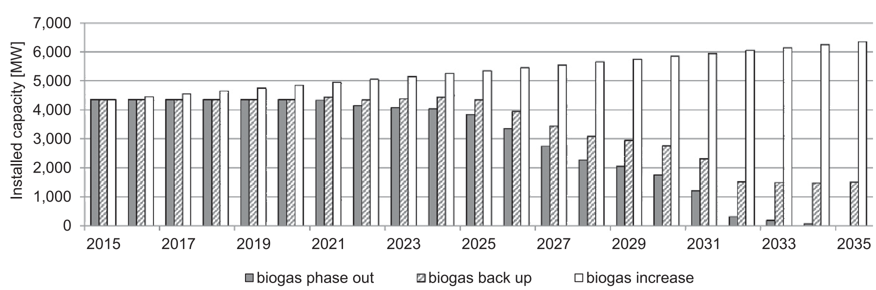

Fig. 2. Installed capacity of biogas plants in three different extension paths.

of the EEG (BMWi, 2016c). However, the 2017 EEG defined a fixed annual onshore wind extention path of 2800 and 2900 MW, respectively (BMWi, 2017). We calculated the future capacities of renewable energies for each year for the period of 2016–2035. In this paper, we used the renewable target values of the EEG and neglected the need to accelerate the renewable expansion for reaching the GHG targets of the Paris Agreement and the German Climate Action Plan 2050. Three extension paths were defined (Fig. 2) which were used to analyze the effect of varying electricity generation in biogas plants:

- *Biogas phase out*: The future perspective of existing biogas plants without a new period of remuneration and without the installation of new biogas plants was used as a reference.
- *Biogas back up*: According to (Repenning et al., 2015) the installed capacity of biogas plants in 2035 will amount to 1.5 GW (Climate Protection Scenario 95). Therefore, as from the year 2021, an annual expansion of 100 MW (gross) is necessary. This extension path is based on the assumption that biogas plants will be a valuable supplement to other flexibility options.
- *Biogas increase:* Biogas will be a relevant and cost-efficient flexibility option in the future. In contrast to the *biogas back up* extension path, an annual expansion of 100 MW (net) for the period of 2016–2035 was taken into account which considers the annual deconstruction of biogas plants. As a consequence, the installed capacity of biogas plants increased by 100 MW each year until 2035.

Compared to *biogas phase out*, the extension paths *biogas back up* and *biogas increase* lead to a decreasing proportion of electricity generated from onshore wind (Table 1). Electricity generated from PV, offshore wind, biomass (without biogas), hydropower and other renewables (which includes gas from purification plants etc.) was assumed to be constant in each extension path (Table 2). The installed capacities of PV plants were taken from (NEP, 2016) which took the expansion of new PV plants of the last three years into account. As a consequence, the EEG goal of 2500 MW PV plants per year will not be reached. It was concluded that biomass (without biogas), hydropower and other renewables produce baseload generation throughout the year. Therefore, power supply from the mentioned energy sources is completely inflexible. According to (NEP,

Table 1
Installed and rated capacities of onshore wind and biogas plants in the extension paths *biogas phase out*, *biogas back up* and *biogas increase* [GW]. Rated capacity is shown in parentheses, unit is [GW]. Missing intermediate values are calculated by linear interpolation.

	2015	2020	2025	2030	2035	Source
Onshore wind						
Biogas phase out	41.7 [6]	44.9	51.4	70.2	87.8	[6] (Lüers et al., 2016), own calculations
Biogas back up	41.7 [6]	44.9	50.3	68.0	84.6	
Biogas increase	41.7 [6]	43.8	47.5	58.5	69.5	
Biogas						
Biogas phase out	4.4 (3.2)	4.4 (3.2)	3.8 (2.8)	1.8 (1.3)	0 (0)	Own calculations according to (BNetzA, 2015a)
Biogas back up	4.4 (3.2)	4.4 (3.2)	4.3 (3.1)	2.8 (1.8)	1.5 [5] (0.8)	Own assumptions, [5] (Repenning et al., 2015)
Biogas increase	4.4 (3.2)	4.9 (3.4)	5.4 (3.7)	5.9 (3.9)	6.4 (4.2)	Own assumptions

2016) the calculation of the installed capacities and the generated electricity was based on the assumption that 2000 annual full load hours (flh) for onshore wind, 4400 flh for offshore wind and 940 flh for PV are produced every year (Tables 3, 4). Biogas plants are defined by special characteristics: Due to the flexibilization of biogas plants and because they produce less than 8760 flh, their installed capacity is not a benchmark for annual electricity generation. Increasing installed capacity through additional or larger combined heat and power units (CHPU) at a constant production of biogas is the most common way to flexibilize biogas plants. As a consequence, flexible electricity generation from biogas plants reduces their annual full load hours. Hence, rated power, as the average electricity generated over one calendar year, is used to quantify the annual electricity generation. Based on (Lauer et al., 2017) the flexibilization of biogas plants can be described by the quotient of installed capacity and rated capacity, i.e. the power quotient (PQ). In terms of the 2014 EEG (BMWi, 2014), calculating the electricity generated from newly installed biogas plants considers a PQ of 2, whereby rated power must not exceed 50% of the installed capacity. As a consequence, Table 3 shows that the annual extension of 100 MW (net) of installed capacity in biogas plants increases the amount of electricity by 0.44 TWh a^{-1} and 2.2 TWh every five years.

A list of conventional power plants (BNetzA, 2015b) was analyzed in order to derive the gross electricity consumption in Germany for the period of 2016–2035. We took into consideration own consumption of conventional power plants in 2014 amounting to 34.9 TWh (BMWi, 2016d) and reduced future own consumption compared to the installed capacity of conventional power plants. A similar approach is used to calculate the must-run capacity for conventional power plants. According to (Lykidi and Gourdel, 2015) nuclear plants will become more flexible in the future, but daily power variations below 50% of installed capacity are not technically feasible. The same applies to lignite-fired power plants with a minimum level of around 50% of installed capacity (Mayer et al., 2013). Must run-capacity is defined here as the minimum load restriction of nuclear and lignite-fired power plants (Table 2), considering the future decreasing capacities of conventional power plants based on (NEP, 2016). Consequently, in this study, the operation of conventional power plants was not taken into account.

2.2. *Residual load and renewable surplus generation for the period of 2016–2035*

Residual load (*RL*) at time *t* is defined here as the hourly electricity demand (*D*) minus hourly generation of intermittent renewable energies (*iRE*) (onshore wind, offshore wind, and PV), controllable renewable energies (*cRE*) (biomass (without biogas), hydropower, and other renewables), biogas (*bgas*), and the must-run capacity of conventional power plants (*MR*) (1):

$$\mathrm{RL}(t) = D(t) – \mathrm{iRE}(t) – \mathrm{cRE}(t) – \mathrm{bgas}(t) – \mathrm{MR}(t) \quad (1)$$

When residual load becomes negative, a surplus is generated. In order to calculate the residual load for the period of 2016–2035, we applied hourly feed-in data from intermittent onshore wind, offshore wind and PV provided by the German transmission system operators based on the data from the years 2012–2015 (ÜNB, 2016). Because of the non-constant monthly generation from (intermittent) renewable energies, official end-of-month instead of end-of-year installation data were used according to the methodology of (Tafarte et al., 2014). The installed capacity was calculated by using a linear interpolation throughout the respective month. In order to derive hourly availability factors for the intermittent renewable energies, hourly electricity generation was divided by the calculated installed capacity. To determine the hourly electricity generated from intermittent renewable energies for a respective year, the availability factor was multiplied by the installed capacity. The availability factors for the period of 2012–2015 were used to derive the hourly electricity generated from intermittent renewable energies. To do so, the factors were repeated every four years for the period of 2016–2035. Instead of using the availability factors of one year, four years were thought to minimize the influence of specific weather and atmospheric conditions for a given year.

Biomass (without biogas), hydropower, other renewables and must-run capacity are meant to generate electricity in baseload operation at a constant level over the entire year. Flexible power generation from biogas plants is optimized to reduce surplus generation (Section 2.4). Finally, hourly load data were taken from the European Network of

Table 2
Installed and rated capacities of renewable energies and must-run capacity of conventional power plants for all extension paths [GW]. Rated capacity is shown in parentheses, unit is [GW]. Missing intermediate values are calculated by linear interpolation.

	2015	2020	2025	2030	2035	Source
(Intermittent) renewable capacities for all extension paths						
PV	39.7 [1]	47.3	54.9 [2]	57.4	59.9 [2]	[1] (BNetzA, 2016b), [2] scenario B 2025/2035 from (NEP, 2016)
Offshore wind	3.3 [3]	6.5 [4]	11.0 [4]	15.0 [4]	19.0 [5]	[3] (Lüers and Rehfeldt, 2016), [4] (BMWi, 2015), [5] own assumptions according to (Repenning et al., 2015)
Renewable baseload capacities for all extension paths						
Biomass (without biogas)	(1.2)					(Scheftelowitz et al., 2015), own assumptions
Hydropower	(2.2)					(AGEB, 2016), own assumptions
Other renewables	(1.3)					Own calculations and assumptions according to (AGEB, 2016)
Must-run capacity for all extension paths						
Must-run capacity	(14.3) (2016)	(11.8)	(6.3)	(5.4)	(4.6)	Own calculations

Table 3
Electricity consumption and generation in the extension paths *biogas phase out*, *biogas back up* and *biogas increase* [TWh a^{-1}]. Calculations based on 2000 full load hours (onshore wind) (NEP, 2016).

	2015	2020	2025	2030	2035	Source
Onshore wind						
Biogas phase out	79.3 [9]	89.9	102.8	140.3	175.7	[9] (AGEB, 2016), own calculations
Biogas back up	79.3 [9]	89.9	100.6	135.9	169.1	
Biogas increase	79.3 [9]	87.7	95.1	117.0	138.9	
Biogas						
Biogas phase out	28.0 [10]	28.0	24.7	11.3	0	[10] (Scheftelowitz et al., 2015), own calculations according to (BNetzA, 2015a), own assumptions
Biogas back up	28.0 [10]	28.0	26.9	15.6	6.6	
Biogas increase	28.0 [10]	30.2	32.4	34.6	36.8	

Table 4
Electricity consumption and generation for all extension paths [TWh a^{-1}]. Calculations based on 2000 full load hours (onshore wind), 4400 (offshore wind) and 940 (PV) (NEP, 2016).

	2015	2020	2025	2030	2035	Source
Electricity consumption						
Gross	604.9 [7]	602.7	597.7	596.4	595.2	[7] (AGEB, 2016), own calculations according to (NEP, 2016)
Net	543.6					Scenario B 2025/2035 (NEP, 2016)
Electricity generation						
Target value EEG	195.9 [7]	232.4	269.0	313.0	357.1	[7] (AGEB, 2016), own calculations according to (BMWi, 2014)
Renewable electricity generation for all extension paths						
PV	38.4 [8]	44.5	51.6	54.0	56.3	[8] (AGEB, 2016), own calculations
Wind offshore	8.7 [8]	28.6	48.4	66.0	83.6	
Biomass (without biogas)	10.6					(Scheftelowitz et al., 2015), own assumptions
Hydropower	19.3					(AGEB, 2016), own assumptions
Other renewables	11.6					Own calculations according to (AGEB, 2016), own assumptions

Transmission System Operators for Electricity (ENTSO-E, 2016) as determined for the year 2015. As also shown in (Schill, 2014), these were multiplied by a factor to correspond to the official German net electricity consumption.

2.3. Optimization of flexible electricity generation from biogas plants

When there is a constant rate of biogas production, flexible electricity generation from biogas plants requires investments in additional CHPU capacities. Furthermore, an extension of the gas storage capacity increases the flexibility of biogas plants due to extended periods between phases of full load electricity generation. In this analysis, the complete flexibility of biogas plants was considered by neglecting gas storage capacities. According to Lauer et al. (2017), the mode of operation can be classified as *semi flexible* and *fully flexible* electricity generation from biogas plants. In the semi flexible mode, biogas plants consist of at least two CHPUs that operate in base and peak load. Baseload means that at least one CHPU is assigned to generate continuous power at 8000 full load hours throughout the year. If the remaining CHPU(s) are in intermittent full load operation at significantly less than 8000 flh this status is defined as peak load. Fully flexible mode of operation assumes that all CHPU(s) are in intermittent peak load operation so that the electrical output of the biogas plant is either 0 or 100% of its installed capacity. Because CHPUs have a lower electrical efficiency during partial load, only full loads were considered (Bianchi et al., 2014).

Another way to flexibilize biogas plants is to vary biogas production by using different temporal feedstock supplies (Mauky et al., 2015). This requires a lower gas storage capacity. This form of flexible biogas production also allows for a seasonal shift in flexible power generation that might facilitate system integration e.g. of strong winds for several days during autumn or winter. This mode of operation is defined as *seasonal* (Fig. 3). In contrast to the *biogas back up* and *biogas increase* extension paths, in the reference *biogas phase out* scenario, biogas plants are not flexible and generate electricity at a constant rate.

In order to derive the optimal flexible electricity generation in biogas plants, a differentiation was made between two fundamental optimization methods: *intraday* and *intra-year* optimization. Semi flexible and fully flexible modes of operation use the intraday optimization method. To do so, the hourly residual load values without biogas plant electricity generation were used for each day within the respective year. The hourly values of one day were placed in an ascending order beginning with the hour of the lowest residual load. Depending on the daily full load hours of the peak load CHPU(s), hours with the highest residual load were chosen for electricity generation. This method is used for all days in a respective year. In contrast, the intra-year optimization method divides one year into three equally sized parts depending on the daily average of hourly residual load values which is used by the *seasonal* mode of operation. The three parts are high, middle and low residual load. Intra-year optimization is characterized by constant electricity generation within one day. The electricity generation changes between 150%, 100% and 50% of rated capacity and is assigned to high, medium, and low residual load.

The number of peak load hours of semi and fully flexible modes of operation within one day depends on the above-mentioned PQ: The higher the PQ the lower the number of peak load hours at constant gas production. According to (BMWi, 2014) a PQ of 2 was used for all newly installed biogas plants using the intraday optimization method. Since 2012 the EEG has been promoting flexible power generation in existing biogas plants with a premium payment. According to (Scheftelowitz, 2016) the PQ of all existing biogas plants that receive the premium payment for flexibility is about 1.4. That is why we used a PQ of 1.4 and non-flexible electricity generation from existing biogas plants to calculate residual load. The premium payment for flexibility is paid for a period of 10 years. As a consequence, flexible power generation is implemented in existing biogas plants when biogas plants reach a remaining 10 years within the EEG remuneration period of 20 years. If biogas plants are older than 10 years by the year 2015, they operate in a non-flexible way over the whole period of remuneration. To compare the influence of a seasonal mode of operation with lower peak load capacities on residual load, the PQ was set to a constant of 1.5 for existing and new installations. The modes of operation, their related optimization methods and the impact of PQ 1.4, 1.5 and 2.0 on the number of peak load hours are summarized in Table 5. In

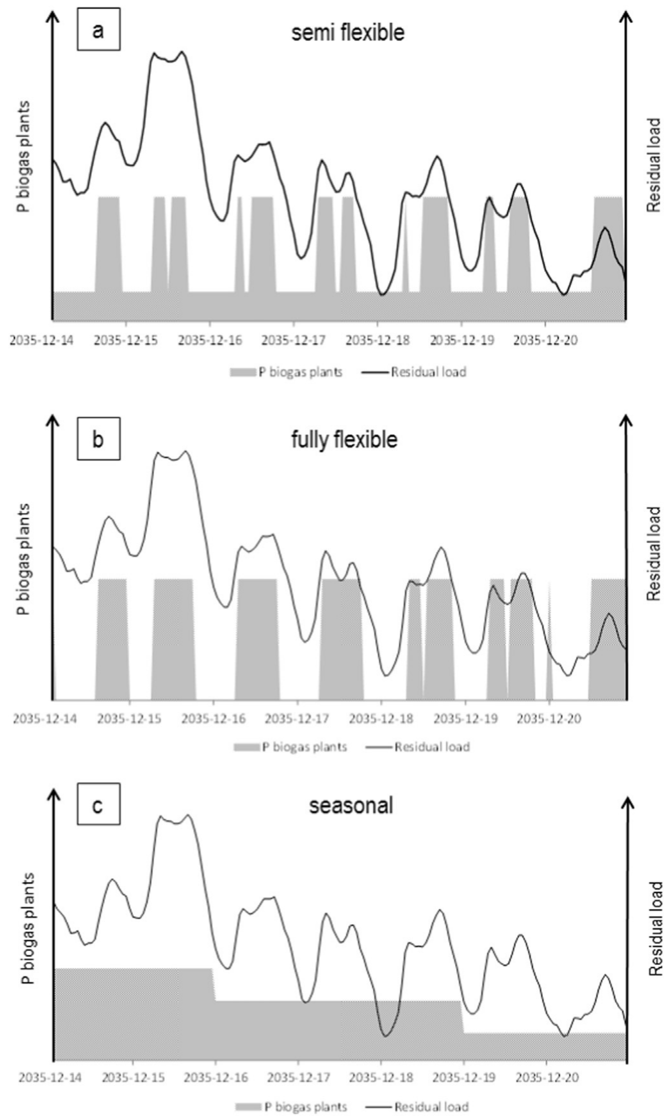

Fig. 3. Overview of modes of operation used in this paper (a: semi flexible, b: fully flexible and c: seasonal). The example shown here is electricity generation from biogas plants in the *biogas increase* extension path based on residual load within seven days in 2035. Abbreviation: P = power.

conclusion, the optimized flexible power generated from biogas plants was used to calculate residual load and surplus generation for each year in the period of 2016–2035.

As a result, 13 scenarios were created by combining different extension paths, modes of operation and the flexibilization of existing biogas plants (Table 6).

2.4. Total premiums and economic assessment using the average integration costs of surplus generation

The EEG guarantees renewable energy producers remuneration on top of the market rate for each kilowatt hour fed into the grid; the sum of the remuneration from the German market premium scheme and market revenues is called the total premium.[2] The remuneration depends on the kind of energy source and the installed/rated capacity of the renewable energy plants. Premium schemes represent a benchmark for the future EEG support costs. Therefore, the AICSG was

[2] Further details on the German market premium scheme are presented, for example, in (Gawel and Purkus, 2013).

Table 5
Overview of modes of operation, optimization methods and peak load hours depending on different PQs to optimize flexible power generation from biogas plants. The difference between semi flexible and fully flexible peak load generation depends on a constant gas production rate and varying baseload generation.

Modes of operation	Optimization method	Flexible power and peak load hours based on different PQs using a biogas plant with 500 kW rated power as an example		
		PQ 1.4 (existing plants)	PQ 1.5	PQ 2.0 (new plants)
Semi flexible	Intraday	Base load 228 kW peak load 663 kW, 15 h d^{-1}	–	Base load 228 kW peak load 953 kW, 9 h d^{-1}
Fully flexible	Intraday	Base load 0 kW peak load 667 kW, 18 h d^{-1}	–	Base load 0 kW peak load 1000 kW, 12 h d^{-1}
Seasonal	Intra-year	–	Base load: 250 kW, 121 d a^{-1} rated power: 500 kW, 123 d a^{-1} peak load: 750 kW, 121 d a^{-1}	–

Table 6
Scenarios based on extension paths, modes of operation and flexibilization of existing biogas plants.

Extension path	Mode of operation	Flexibilization of existing biogas plants	Scenario
Biogas phase out(reference scenario)	Non-flexible	No	R
Biogas back up (BU)	Semi flexible (SF) Fully flexible (FF) Seasonal (SL)	Yes (+)No (—)	BU-SF+ BU-SF— BU-FF+ BU-FF— BU-SL+ BU-SL—
Biogas increase (IN)	Semi flexible (SF) Fully flexible (FF) Seasonal (SL)		IN-SF+ IN-SF— IN-FF+ IN-FF— IN-SL+ IN-SL—

calculated by using the ratio between total premiums and surplus generation for the different scenarios in the period of 2016–2035 (Table 7). Future total premiums for intermittent renewable energies are based on (Öko-Institut, 2015). The presented total premiums of PV plants may be considered to be conservative; in February 2017, the large freestanding PV installations average auction price was 65.8 € MWh^{-1} in Germany (BNetzA, 2017). For biogas plants the total premium was calculated by using the data from (BMWi, 2016e). Since 2016, the maximum total premium, including the spot price of electricity, has been limited to 169 € MWh^{-1}. More than 50% of the LCOE of biogas plants is due to consumption-related expenses, which depend on the cost of feedstock (Scheftelowitz et al., 2014). As a consequence, the future cost reduction potential of biogas plants is severely limited. Furthermore, compared to non-flexible electricity generation, the flexibilization of biogas plants leads to further costs

Table 7
Total premiums [€ MWh^{-1}] for all extension paths and scenarios for the period of 2016–2035, including the spot price of electricity in Germany. The premium payment for flexibility is in addition to the total premium of existing biogas plants and is given in brackets. Missing intermediate values are calculated by linear interpolation and based on our own assumptions.

	2015	2020	2025	2030	2035
Onshore wind	89 [11]	81	72 [11]	63	53 [11]
Offshore wind	194 [11]	169	143 [11]	126	109 [11]
PV	110 [11]	107	103 [11]	94	84 [11]
Biogas semi flexible			189(3.4) [12]		
Biogas fully flexible			209(3.5) [12]		
Biogas seasonal			189(5.9) [12]		

[11] (Öko-Institut, 2015), [12] (BMWi, 2014)

amounting to 20–50 € MWh^{-1} (Hauser et al., 2014). We have taken into account the improved efficiency of CHPUs and have assumed a total premium of 189 € MWh^{-1} over the whole period based on new biogas plants that generate electricity in a semi flexible way. The fully flexible mode of operation increases capital-related expenditures through additional investments in gas or heat storage capacities as well as increased CHPU capacities. Therefore, we assumed a total premium of 209 € MWh^{-1} for the fully flexible mode of operation. The flexibilization rate of biogas production can reduce investments in additional storage capacities (Grim et al., 2015). However, investments in further CHPU capacities are still necessary and therefore a total premium of 189 € MWh^{-1} for seasonal operation was taken into account. The premium payment for flexibilizing existing biogas plants was calculated according to (BMWi, 2014).

Flexible power generation from biogas plants is assessed by comparing the total premiums and surplus generation of scenarios with different biogas percentages and modes of operation. Comparing the average integration costs of surplus generation (AICSG) of a renewable portfolio with a higher share of onshore wind (reference scenario) to an increased share of biogas plants (scenario x) might be an indicator for the economic value of flexible power generation from biogas (Fig. 4):

IF $sg_{scx} < sg_{ref}$

AND $tp_{scx} > tp_{ref}$

$$\text{THEN}\quad AICSG[€\,MWh^{-1}] = \Delta tp[€]/\Delta sg[MWh] \tag{2}$$

$$\Delta tp = tp_{scx}[€] - tp_{ref}[€] \tag{3}$$

$$\Delta sg = sg_{ref}[MWh] - sg_{scx}[MWh] \tag{4}$$

where tp_{scx} is the sum of total premiums over a certain period in scenario x, tp_{ref} is the sum of total premiums over a certain period in the reference scenario, sg_{ref} is the sum of surplus generation events over a certain period in the reference scenario, and sg_{scx} is the sum of surplus generation events over a certain period in scenario x.

The lower the AICSG the better the scenario is considered to be.

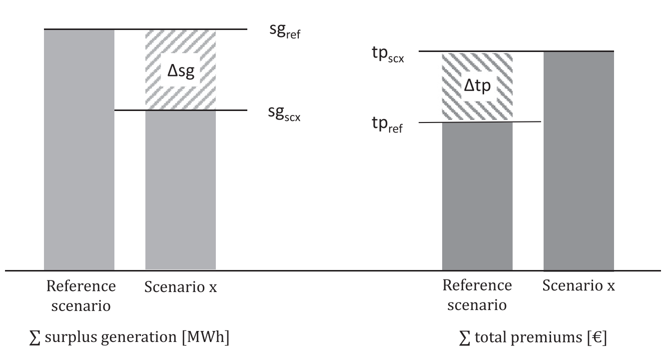

Fig. 4. Definition of average integration costs of surplus generation (AICSG) to assess scenarios with different renewable energy portfolios.

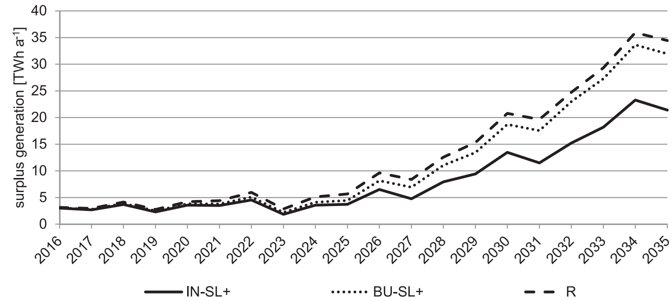

Fig. 5. Surplus generation in the *biogas increase* and *biogas back up* extension paths with seasonal mode of operation and flexible existing biogas plants (IN-SL+ | BU-SL+) as well as in the reference scenario (R) for the period of 2016–2035.

3. Results

3.1. Surplus generation in the biogas extension paths

In all extension paths, surplus generation increases in the period of 2016–2035 due to the additional capacities of intermittent renewable energies (Fig. 5). Surplus generation is impacted to the largest extent in the *biogas phase out* extension path. The greatest annual increase in surplus generation begins in the mid-2020s, when existing biogas plants stop operation. Without the installation of new biogas plants, surplus generation increases from 3.1 in 2016 to 34.4 TWh a^{-1} in 2035 (reference scenario). In the reference scenario, total surplus generation over the period of 2016–2035 is calculated to be 252.0 TWh. In contrast, the surplus generation in the *biogas increase* and *biogas back up* extension paths goes down due to an increase in the installation of biogas plants instead of intermittent wind power plants. Thus, compared to *biogas phase out*, the reduction in the *biogas back up* extension path was lower by 19.6–24.6 TWh in the period of 2016–2035 depending on the mode of operation. This is due to the fact that the annual expansion of 100 MW (gross) in the *biogas back up* extension path leads to an increased share of wind power plants, compared with the *biogas phase out* extension path. Because it has the highest share of biogas plants, surplus generation in the *biogas increase* extension path decreases to 164.1–172.8 TWh a^{-1}. Fig. 5 also shows the importance of the chosen feed-in data year for onshore wind, offshore wind and PV. We used four different years for feed-in data (2012–2015) repeating this for the period of 2016–2035. Therefore, the annual surplus generation in all scenarios did not increase continuously each year. In some years the surplus generation decreases, whereas the share of intermittent renewable energies is higher than the year before; in 2019 surplus generation is lower than in 2018, although the electricity generation from intermittent renewable energies increases compared to the year 2018 (Fig. 5). The chosen year of the hourly feed-in data of renewable energies has a major influence on surplus generation due to the temporal distribution of especially long and strong wind events.

3.2. The optimization of flexible electricity generation from biogas plants

3.2.1. The preferable mode of operation

In addition to the extension paths, the modes of operation selected for biogas plants influence the density and intensity of surplus generation. As shown in Fig. 6 the surplus generation over the period of 2016–2035 was primarily influenced by the extension paths. Nevertheless, differences in terms of the observed modes of operation were apparent. Overall, it was shown in both extension paths that the highest values for surplus generation occurred in semi flexible operation and the lowest values in seasonal mode of operation. The difference between semi flexible and seasonal mode of operation in the *biogas back up* extension path was 5.0 TWh over the entire period. When the proportion of biogas plants was higher in the *biogas increase* extension pathway, this difference increased to 8.7 TWh. Due to the partial baseload in semi flexible mode of operation,

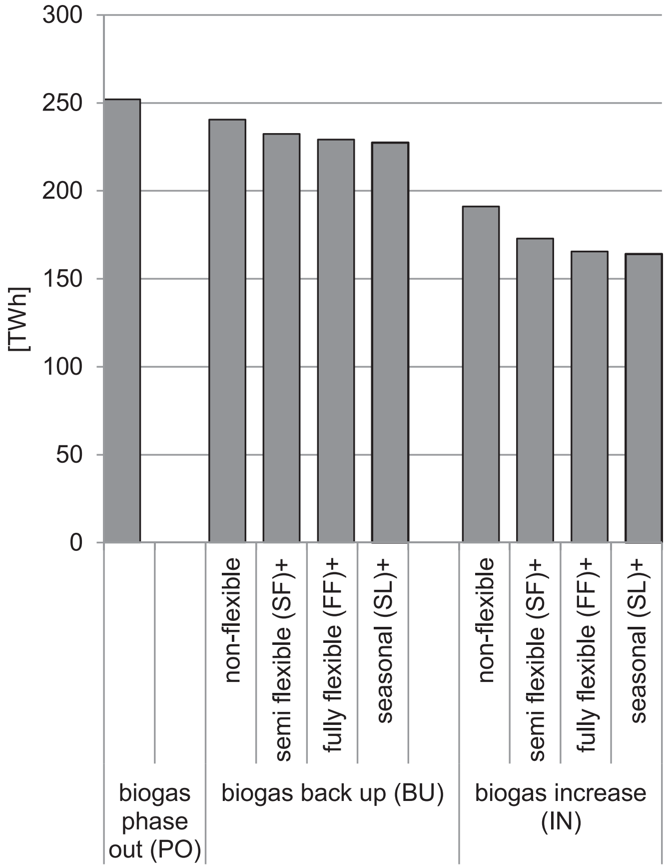

Fig. 6. Surplus generation in all scenarios with regard to flexible power generation in existing plants (+) and in the period of 2016–2035. In addition, results of non-flexible power generation in extension paths *biogas back up* and *biogas increase* are shown.

higher surplus generation in both extension paths was identified, especially when there was an increase in the installed capacity of the biogas plants. Hence, to avoid surplus generation, a preferably high percentage of biogas plants should be generating electricity flexibly without baseload operation.

The results of fully flexible and seasonal modes of operation were less diverging: 1.8 TWh in the *biogas back up* extension path and 1.5 TWh in the seasonal extension path. In particular, the results of the chosen mode of operation depended on the temporal occurrence of surplus generation events. A seasonal mode of operation is preferable for surplus generation events that last for days or weeks in autumn or winter whereas a higher percentage of PV plants favors the intraday optimization of biogas plants in the fully flexible mode of operation.

In summary, the German renewable extension paths that focus on electricity from onshore wind slightly prefer more seasonal, flexible power generation from biogas plants.

3.2.2. *The flexibilization of existing biogas plants*

The difference between non-flexible and flexible electricity generation from existing biogas plants is shown below. As described in Fig. 7 existing biogas plants generate power in a flexible way and surplus generation is lower than when operation is not flexible. For example, in scenario BU-FF+ renewable surplus generation is 7.4 TWh a^{-1} below the value for the same mode of operation when the existing biogas plants do not operate flexibly. The difference for seasonal mode of operation increases to 9.5 TWh a^{-1}. Fig. 8 shows the temporal distribution of additional surplus generation by comparing existing flexible (BU-SL+) and non-flexible biogas plants in the *biogas back up* extension path as well as seasonal mode of operation (BU-SL–) for each year and for the period of 2016 – 2035. In scenario BU-SL–, the annual additional surplus generation increases by 0.9 TWh a^{-1} until the year 2026. After the mid-2020s, the effect of flexible existing plants

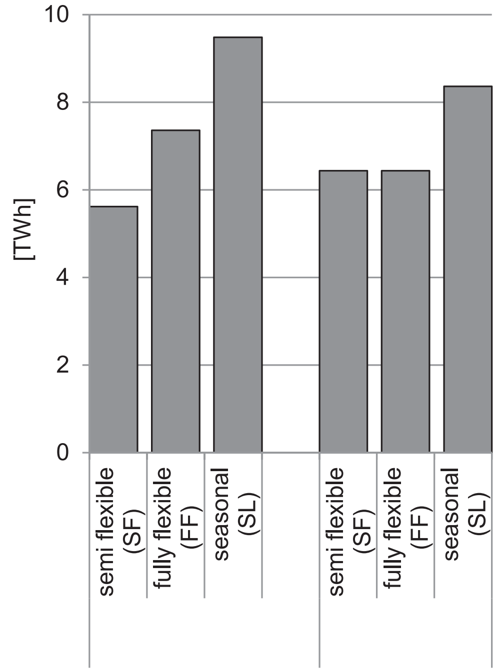

Fig. 7. Increased surplus generation for the period of 2016–2035 of non-flexible power generation in comparison to flexible operation in existing biogas plants.

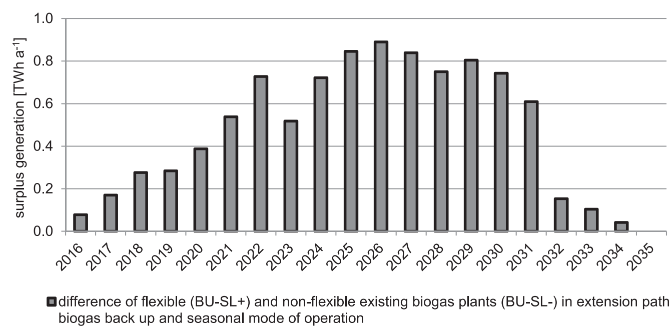

Fig. 8. Temporal distribution of additional surplus generation by non-flexible (BU-SL–) compared to flexible power generation in existing biogas plants (BU-SL+) in the *biogas back up* extension path and seasonal mode of operation.

goes down due to decommissioning after 20 years of remuneration. In 2035, no positive effect on existing flexible plants could be determined. In summary, when surplus generation increases from the middle of the 2020s (Fig. 5), the flexible capacity of existing biogas plants is reduced.

3.3. *Total premiums and average integration costs of surplus generation*

Table 8 shows the sum of total premiums for the period of 2016–2035 based on extension path, mode of operation and flexible electricity generation in existing biogas plants. Without the installation of new biogas plants, the sum of total premiums for renewable energies is about 11 bn €. The LCOE of biogas plants is essentially higher than for intermittent renewable energies. The sum of total premiums increases to 12.6–13.3 bn € in the *biogas back up* extension path when the flexibilization of existing biogas plants is also taken into account. In the *biogas increase* extension path, total premiums increased to 16.3 in semi flexible and 17.1 bn € in fully flexible mode of operation because of the higher proportion of biogas plants. Due to the PQ of 1.5 (and higher premium payments for flexibility) in seasonal mode of operation instead of 1.4 in semi flexible and fully flexible mode of operation, the sum of total premiums and premium payments for flexibility were the highest with this kind of flexible electricity generation. Fully flexible electricity generation requires additional gas storage and higher CHPU capacities. This leads to

Table 8
Sum of total premiums (and premium payments for flexibility) for the period of 2016–2035 in all scenarios [10^3k€]. Results are presented with and without flexible electricity generation from existing biogas plants.

	Flexible electricity generation from existing biogas plants	Non-flexible electricity generation from existing biogas plants
Biogas increase		
Semi flexible	16,334	15,506
Fully flexible	17,096	16,241
Seasonal	16,972	15,506
Biogas back up		
Semi flexible	12,620	11,792
Fully flexible	12,778	11,923
Seasonal	13,258	11,792
Biogas phase out		
	10,985	

higher LCOE compared to other modes of operation. The total premiums without the flexibilization of existing biogas plants decreases to 11.8–11.9 bn € in the *biogas back up* extension path and to 15.5 and 16.2 bn € in the *biogas increase* extension path because of saved premium payments for flexibility.

Table 9 lists the AICSG of all scenarios for the reference scenario R. The AICSG varies between 53.37 and 92.39 € MWh^{-1}. In general, when existing plants also generate electricity flexibly, three out of the four scenarios in the *biogas back up* extension path show the lowest AICSG of between 53.37 and 60.61 € MWh^{-1}. However, combining the *biogas back up* extension path and the flexibilization of existing plants increases the AICSG to 92.39 € MWh^{-1}. In both extension paths the seasonal mode of operation for non-flexible power generation in existing biogas plants shows the best results at 53.37 (back up) and 56.87 € MWh^{-1} (increase). Due to lower investments in additional gas storage and CHPU capacities, the seasonal mode of operation becomes more cost-effective.

Flexible electricity generation in existing biogas plants increases the AICSG in all scenarios. As a result, the flexibilization of existing biogas plants is not as cost-effective as the installation of new biogas plants within the next decades. Although, the additional costs for flexibilizing existing plants are quite low compared to the LCOE of new biogas plants, surplus generation events do occur, especially from the mid-2020s onwards so that the reduction in surplus generation in existing plants is lower. In the *biogas back up* extension path the seasonal mode of operation in existing non-flexible plants (scenario BU-SL–) achieves the overall best result (53.37 € MWh^{-1}).

4. Discussion

4.1. Average integration costs of surplus generation

The LCOE is often used in public debates to assess the cost efficiency of the energy transformation process. However, the integration of (intermittent) renewable energies into the energy system requires further technologies that result in additional costs; e.g. storage technologies. Due to the different generation characteristics of renewable energies, using the LCOE is not an appropriate approach for comparing controllable biogas plants with intermittent renewable energies. Compared to PV or wind plants, demand-oriented electricity generation from biogas plants can reduce the supply of other flexibility options. Identifying surplus generation using the AICSG improves the economic assessment of different renewable energy portfolios. The AICSG combines the LCOE of renewable energies and the calculated surplus generation. This means that using the AICSG focuses on system integration. Hence, the AICSG allows a more comprehensive economic assessment of various renewable energy portfolios characterized by varying proportions of intermittent and controllable generation technologies. In addition, by using the AICSG, renewable energy extension paths, including biogas plants, can be compared with other flexibility options, such as storage technologies and DSM.

Table 9
Overview of average integration costs of surplus generation in all scenarios under observation (period 2016 – 2035).

AICSG [€ MWh^{-1}]	Extension path	Mode of operation	Flexible existing plants
53.37	Back up	Seasonal	No
56.87	Increase	Seasonal	No
57.51	Back up	Semi flexible	No
60.61	Back up	Fully flexible	No
61.08	Increase	Semi flexible	No
65.76	Increase	Fully flexible	No
67.60	Increase	Semi flexible	Yes
68.14	Increase	Seasonal	Yes
70.76	Increase	Fully flexible	Yes
78.52	Back up	Fully flexible	Yes
83.23	Back up	Semi flexible	Yes
92.39	Back up	Seasonal	Yes

4.2. Discussion of limitations

The AICSG derived from surplus generation is particularly driven by the simplification that Germany is a "copper plate" without German domestic grid bottlenecks. In 2013, the curtailment of renewable energies in Germany was about 1.6 TWh as a consequence of absent net capacities (BNetzA, 2016a). This curtailment could increase in the future if grid expansion is insufficient. Furthermore, the import and export of electricity to neighboring countries was not taken into consideration even though this interconnection may reduce surplus generation in Germany and smooth the residual load curve.[3] In addition, we assumed an identical load curve for each year in the period of 2016–2035. Due to the increasing electrification of the mobility and heating sector, consumption behavior will change in the future. However, the derivation of possible load curves would go beyond the scope of this study. It was assumed that the identified hourly availability factors for the years 2012–2015 are constant for the entire 20 years. In future, hourly availability factors may be subject to change over time, which is driven by turbines for weak wind conditions combined with increasing full load hours and a more constant electricity generation. Moreover, the peak load of PV generation at noon can be reduced by a western and eastern orientation instead of a southern orientation (Hartner et al., 2015). A further simplification is the derivation of a must-run capacity, consisting of 50% of the installed nuclear and lignite capacity in Germany. Not only technical restrictions lead to a must-run capacity, but also the provision of ancillary services and heat. At the same time, the flexibility of biogas plants was considered to be absolute, so that gas storage was endless. This assumption results in an overestimation of the reduced surplus generation in biogas plants. Furthermore, even if the majority of biogas plant operators decides to generate electricity in a flexible way, electricity generation will be optimized from the operator's point of view. In summary, the benefit from flexible biogas plants may be lower than forecasted here. The total premiums for the installation of new biogas plants and different modes of operation represent estimations. To get a more detailed description of the results, it would be necessary to calculate the LCOE using different types of biogas model plants to represent the cost structure of all plants.

4.3. Sensitivity analysis

Fig. 9 shows the sensitivity analysis of the scenario IN-FF+. This shows how much the AICSG is impacted by the total premiums for new biogas installations and onshore wind plants, and the difference in surplus generation. The total premiums for new onshore wind plants impact the AICSG less than other parameters, such as the total premiums for new biogas installments and the difference in surplus

[3] Further details are shown, for example, in (Brouwer et al., 2016).

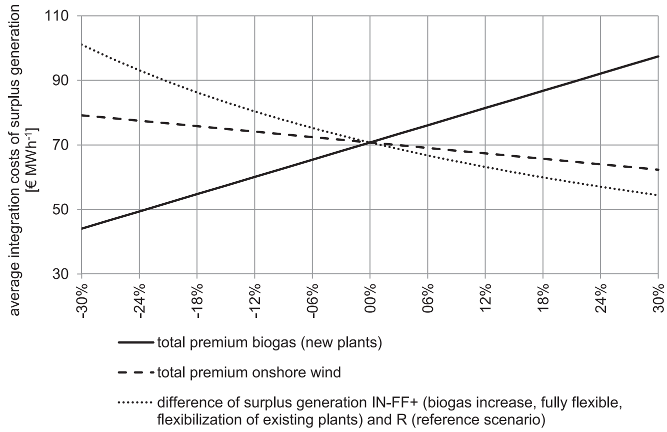

Fig. 9. Sensitivity analysis of the *biogas increase* extension path, fully flexible mode of operation and flexible power generation from existing biogas plants (scenario IN-FF+) for the period of 201–2035.

generation. Increasing total premiums for onshore wind reduces the gap between the remuneration of onshore wind and biogas, hence, the AICSG decreases as total premiums for onshore wind increase. This is because the difference between total premiums for onshore wind and biogas and, hence, the nominator of the AICSG would decrease. The parameters that decisively affected the results of the AICSG were the total premiums for new biogas installments and the difference in surplus generation. By varying both parameters between −30% and 30%, the highest value for the total premium of new biogas installments was 97 € MWh^{-1}; the lowest was 44 € MWh^{-1}. The opposite is true for the correlation between the difference in surplus generation and the variation of the parameter. An increasing difference in surplus generation leads to a lower AICSG. The sensitivity is lower than by varying the total premium of new biogas installments so that the AICSG varies between 54 € MWh^{-1} and 101 € MWh^{-1}.

5. Conclusions and policy implications

Today about 4% of gross electricity consumption is produced by biogas plants. These can be used to improve the system integration of intermittent renewable energies; however, current biogas plants are mainly in baseload operation. Besides the technical implementation of flexible electricity generation from biogas plants, the beneficial use of flexibility in biogas plants within the energy system has to be evaluated from an economic point of view.

In this study, we analyzed surplus generation in a context of decrease of gross electricity consumption for the period of 2016 – 2035 based on three extension paths, modes of operation and the flexibilization of existing biogas plants with a varying proportion of biogas and onshore wind plants in Germany. The quotient of the total premiums and the differences in surplus generation, compared to the reference scenario, was used as an economic benchmark for flexible biogas plants.

Firstly, as the proportion of the biogas plants in the electricity system increases, future surplus generation is reduced. When the proportion of biogas plants increases on a continuous basis (the *biogas increase* extension path) the lowest surplus generation is between 164 and 173 TWh in the period of 2016–2035. This corresponds to a reduction of 31–35% compared to if the biogas plants were to be phased out. Using biogas plants as a future flexibility option (the *biogas back up* extension path) with an installed capacity of 1500 MW (which correspond to one third of the current capacity) decreases surplus generation by about 8–10% compared to the reference scenario in the same period. Secondly, to avoid surplus generation, the optimal biogas plant mode of operation should be as flexible as possible. Remaining baseload operation of CHPUs increases surplus generation and reduces the flexible electricity output of biogas plants. The current extension paths of renewable energies favor electricity generated by wind power plants over PV. As a consequence, surplus generation events might even occur for several days, especially during autumn and winter. Biogas plants with a seasonal mode of operation reduce surplus generation by wind power plants in a more efficient way. Therefore, we conclude that a combination of a daily and seasonal shift in electricity generation might improve the potentials of biogas plants; both PV generation at noon and wind generation in autumn and winter could be better integrated into the electricity system. Thirdly, an economic assessment using the AICSG approach shows that a constant expansion of biogas plants (biogas increase scenarios) could be more cost-effective for the energy transformation process than a reduction in their installed capacity in biogas back up. Furthermore, the flexibilization of existing biogas plants increases the AICSG in all scenarios. Due to the low surplus generation until the mid-2020s, existing flexible plants are not as cost-effective as new installations. These results are based on conservative future total premiums for PV plants.

Besides the LCOE, policy makers can conclude that additional benchmarks for a cost-effective transformation of the electricity system are needed. For the economic assessment of future renewable energies, extension paths, the combination of different renewable generation technologies and further flexibility options have to be considered. Therefore, biogas plants are one option for improving the system integration of intermittent renewable energies. At the same time, costs for additional flexibility options can be reduced by flexible biogas plants. However, many flexibility options for the system integration of intermittent renewable energies will be available in future. A comprehensive economic analysis includes different flexibility options and varying percentages of renewable energy technologies. Thus, the optimal combination of flexibility options leads to an economically feasible transformation process. Overall, the reduction of non-flexible electricity generation that increases surplus generation (and variance in the residual load curve) is a key element in the savings from flexibility options and the cost-effective transformation process. Nevertheless, future surplus generation is needed to decarbonize the mobility and heating sector, so that also the second best scenarios of our analysis might become relevant for the very ambiguous GHG emission reduction scenarios, as they are currently discussed for Germany (BMUB, 2016).

From the broader perspective of policymakers we recommend the following strategies:

- Consideration of the interaction between all renewable energies within the energy system. The economic assessment of the energy system transformation process has to include the additional costs for the system integration of intermittent renewable energies.
- Additional costs for the flexibilization of existing biogas plants are quite low. Due to the low surplus generation events until the mid-2020s, the expansion paths of renewable energies might thwart the instrument of the premium payment for flexibility in existing biogas plants. Therefore, we suggest increasing the extension paths of renewable energies within the EEG which might improve the cost efficiency of existing flexible biogas plants.
- Compared to existing plants, new biogas installations are characterized by a better cost efficiency because of the more frequent surplus generation events after the mid-2020s. Nevertheless, the optimal extension path for new biogas plants has to be orientated towards the cost development of other flexibility options such as storage technologies.
- Non-flexible power generation, such as lignite-fired plants, should be removed in order to decrease surplus generation[4] and create sufficient price signals to integrate intermittent renewable energies into the energy system through flexibility options.

For future research, we suggest a more comprehensive economic

[4] Results without must-run capacity are presented in the appendix (Table B.1).

assessment of biogas plants as a flexibility option in various extension paths. Therefore, biogas plants have to be compared with other technologies. Especially storage technologies are expected to grow further in the future and compete with biogas plants. Consequently, an economic assessment that compares biogas plants and storage technologies would be a promising field of research. To do so, a model which overcomes the limitations mentioned of the AICSG has to be developed that calculates the demand of storage as a function of flexible power generation from biogas plants. A cost-benefit analysis would enable a comprehensive economic assessment to be made.

Acknowledgements

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Appendix A

See appendix Tables A.1 and A.2 here

Table A.1
Surplus and conventional generation for selected years and each scenario [TWh a^{-1}]. Existing plants in the *biogas increase* and *biogas back up* extension paths are considered with a PQ of 1.4.

		Biogas increase			Biogas back up			Biogas phase out
		Semi flexible	Fully flexible	Seasonal	Semi flexible	Fully flexible	Seasonal	Non-flexible
2016	Surplus generation	3.03	3.00	3.00	3.08	3.06	3.05	3.13
	Conventional generation[a]	211.56	211.53	211.53	211.60	211.58	211.58	211.66
2020	Surplus generation	3.69	3.58	3.55	3.98	3.89	3.84	4.22
	Conventional generation[a]	211.70	211.58	211.56	211.98	211.90	211.84	212.23
2025	Surplus generation	3.95	3.69	3.72	4.75	4.56	4.45	5.66
	Conventional generation[a]	223.39	223.13	223.17	224.19	224.00	223.90	225.10
2030	Surplus generation	14.30	13.76	13.48	19.21	18.98	18.71	20.79
	Conventional generation[a]	197.35	196.81	196.52	202.26	202.03	201.75	203.83
2035	Surplus generation	22.63	21.88	21.41	32.22	32.02	31.96	34.43
	Conventional generation[a]	169.27	168.52	168.05	178.86	178.66	178.60	181.08
∑ 2016–2035	Surplus generation	172.83	165.59	164.10	232.32	229.12	227.36	251.96
	Conventional generation[a]	4088.32	4081.07	4079.60	4147.81	4144.60	4142.84	4167.45

[a] Conventional generation is calculated here without a must-run capacity (positive residual load) that is also generated by conventional power plants.

Table A.2
Surplus and conventional generation for selected years and each scenario [TWh a^{-1}]. Existing plants in the *biogas increase* and *biogas back up* extension paths generate electricity non-flexible. Values in brackets show the difference to the values in Table A.1 (flexible electricity generation).

		Biogas increase			Biogas back up			Biogas phase out
		Semi flexible	Fully flexible	Seasonal	Semi flexible	Fully flexible	Seasonal	Non-flexible
2016	Surplus generation	3.08 (+0.05)	3.08 (+0.07)	3.08 (+0.08)	3.13 (+0.05)	3.13 (+ 0.07)	3.13 (+0.08)	3.13
	Conventional generation[a]	211.61 (−0.05)	211.60 (−0.07)	211.61 (−0.08)	211.66 (−0,06)	211.66 (−0.07)	211.66 (−0.08)	211.66
2020	Surplus generation	3.93 (+0.24)	3.90 (+0.32)	3.92 (+0.37)	4.22 (+0.24)	4.22 (+ 0.33)	4.22 (+0.39)	4.22
	Conventional generation[a]	211.94 (−0.24)	211.90 (−0.32)	211.93 (+0.37)	212.23 (−0.25)	212.23 (−0.33)	212.23 (−0.39)	212.23
2025	Surplus generation	4.48 (+0.52)	4.33 (+0.64)	4.46 (+0.74)	5.30 (+0.56)	5.26 (+0.69)	5.30 (+0.85)	5.66
	Conventional generation[a]	223.92 (−0.52)	223.77 (−0.64)	223.91 (−0.74)	224.75 (−0.56)	224.70 (−0.69)	224.74 (−0.85)	225.10
2030	Surplus generation	14.60 (+0.30)	14.13 (+0.36)	14.11 (+0.63)	19.56 (+0.34)	19.44 (+0.46)	19.46 (+0.74)	20.79
	Conventional generation[a]	197.65 (−0.30)	197.17 (−0.36)	197.15 (−0.63)	202.60 (−0.34)	202.48 (−0.46)	202.50 (−0.75)	203.83
2035	Surplus generation	22.63 (± 0.00)	21.88 (± 0.00)	21.41 (± 0.00)	32.22 (± 0.00)	32.02 (± 0.00)	31.96 (± 0.00)	34.43
	Conventional generation[a]	169.28 (± 0.00)	168.52 (± 0.00)	168.05 (± 0.00)	178.86 (± 0.00)	178.66 (± 0.00)	178.60 (± 0.00)	181.08
∑ 2016–2035	Surplus generation	177.94 (+5.11)	172.03 (+6.43)	172.46 (+8.36)	237.93 (+5.61)	236.48 (+7.36)	236.84 (+9.48)	251.96
	Conventional generation[a]	4,093.42 (−5.10)	4,087.50 (−6.43)	4,087.96 (−8.36)	4,153.42 (−5.62)	4,151.96 (−7.36)	4,152.33 (−9.48)	4,167.45

[a] Conventional generation is calculated here without a must-run capacity (positive residual load) that is also generated by conventional power plants.

Appendix B

See appendix Table B.1 here

Table B.1
Surplus and conventional generation for selected years and each scenario [TWh a^{-1}]. Existing plants in the *biogas increase* and *biogas back up* extension paths are considered with a PQ of 1.4. In contrast to Table A.1, results are calculated without must-run capacity.

		Biogas increase			Biogas back up			Biogas phase out
		Semi flexible	Fully flexible	Seasonal	Semi flexible	Fully flexible	Seasonal	Non-flexible
2016	Surplus generation	0.16	0.15	0.16	0.16	0.16	0.16	0.17
	Conventional generation	333.58	333.57	333.58	333.57	333.57	333.58	333.59
2020	Surplus generation	0.44	0.38	0.44	0.56	0.48	0.53	0.63
	Conventional generation	311.61	311.55	311.61	311.72	311.65	311.69	311.80
2025	Surplus generation	1.62	1.46	1.53	2.00	1.85	1.89	2.52
	Conventional generation	276.25	276.09	276.16	276.63	276.48	276.52	277.15
2030	Surplus generation	9.51	9.15	8.82	10.37	13.38	13.10	14.84
	Conventional generation	240.08	239.72	239.38	240.93	243.94	243.67	245.40
2035	Surplus generation	15.47	14.76	14.50	17.40	23.87	23.84	26.11
	Conventional generation	201.97	201.25	201.00	203.90	210.37	210.37	212.61
∑ 2016–2035	Surplus generation	96.67	91.44	90.22	144.73	142.51	141.49	159.47
	Conventional generation	5415.96	5410.71	5409.52	5464.02	5461.79	5460.77	5478.75

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Article 2

Flexible Biogas in Future Energy Systems—Sleeping Beauty for a Cheaper Power Generation

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Article

Flexible Biogas in Future Energy Systems—Sleeping Beauty for a Cheaper Power Generation

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Abstract: The increasing proportion of intermittent renewable energies asks for further technologies for balancing demand and supply in the energy system. In contrast to other countries, Germany is characterized by a high installed capacity of dispatchable biogas plants. For this paper, we analyzed the total system costs varying biogas extension paths and modes of operation for the period of 2016–2035 by using a non-linear optimization model. We took variable costs of existing conventional power plants, as well as variable costs and capital investments in gas turbines, Li-ion batteries, and pumped-storage plants into account. Without the consideration of the costs for biogas plants, an increasing proportion of biogas plants, compared to their phase out, reduces the total system costs. Furthermore, their flexible power generation should be as flexible as possible. The lowest total system costs were calculated in an extension path with the highest rate of construction of new biogas plants. However, the highest marginal utility was assessed by a medium proportion of flexible biogas plants. In conclusion, biogas plants can be a cost-effective option to integrate intermittent renewable energies into the electricity system. The optimal extension path of biogas plants depends on the future installed capacities of conventional and renewable energies.

Keywords: biogas; system integration; flexibility options; total system costs

1. Introduction

The increasing greenhouse gas (GHG) emissions and the resulting negative impacts of climate change compel the international community to act. In December 2015, the Paris Agreement was signed to limit global warming to one and a half degree Celsius compared with preindustrial levels [1]. Worldwide, net zero carbon emissions has to be achieved by the middle of the 21st century [2]. By 2050, in order for Germany to reduce GHG emissions by at least 80% compared to 1990, the German government's Energy Action Plan 2050, signed in 2016, aims to decrease total GHG emissions by 55–56% and the energy sector's GHG emissions by 61–62% by 2030 [3]. The proportion of renewable energies in the electricity system is specified by the Renewable Energy Sources Act (EEG), by 2025 the proportion should make up 40–45% of gross electricity consumption and by 2035 55–60% [4]. According to the EEG, the future German electricity generation will be based on intermittent renewable energies, namely wind and photovoltaic plants [4]. Due to their intermittency of power generation, further technologies balance the demand and supply, such as demand-side management (DSM), grid extension, storage technologies, and supply-side flexibility, which can be used to integrate them into the energy system [5,6]. In contrast to other countries in Europe, in 2016 17.2% of Germany's renewable electricity generation was generated by biogas plants [7], whereby these are the most important dispatchable renewable energy. As a consequence, flexible power generation from biogas plants can be one technical solution of low GHG emissions to integrate intermittent renewable energies into the electricity system [8–10]. Furthermore, compared to the use of biogas and biomethane (a natural gas substitute) for direct heating or transport in Germany, the highest GHG emission savings can be achieved by the generation of heat and electricity in combined heat and power units (CHPU) [11].

Nevertheless, in 2016, the German Government has decided to decrease the installed capacity and the electricity generated by biomass (and biogas) plants within the next decades. The EEG reform limits the annual expansion to a maximum of 150 MW (2017–2019) and 200 MW (2020–2022) [4]. Due to the average biogas plants installation of 350 MW per year in the period of 2004–2014 [12], fewer biogas plants will be built and those remaining will begin to close down after their 20 year periods of remuneration in the 2020s. As a result, the installed capacity of biomass, and especially biogas plants, will be reduced and other flexibility options will become more important to ensure there is a sufficient power supply based on intermittent renewable energies in the future German electricity system. If flexible power generation from biogas plants decreases, additional capacities of storage technologies and dispatchable (conventional) power plants might be needed that accompany enhancing investments. In this study, we calculate the total system costs in the future German electricity system depending on varying biogas extension paths.

The cost-effective transformation of the energy system towards decarbonization and an increasing proportion of renewable energies in the electricity, as well as in the heating and mobility sector, is a topic of a high number of publications in recent years. Urzúa et al. [13] showed the impact of an increasing proportion of intermittent renewable energies on the total system costs in Chile. Due to additional costs for transmission and renewable energy capacities, the total costs increase with further wind and solar plants. Due to this, the investments in coal-fired power plants and their base-load operation are cheaper than the combination of (intermittent) renewable energies and transmission grids. Therefore, they argue that dispatchable renewable energies, such as base-load generated hydropower or biomass, can be better integrated in the existing energy system of Chile. Jacobson et al. [14] analyzed the social cost of a 100% renewable US energy system by 2050–2055, including all sectors. Compared to a fossil system, they calculated that the power generation by wind, water, and solar is more economically feasible when the cost of health and climate are integrated. The cost of the electric system in a renewable energy system is about 11.37 ct·kWh^{-1}, while, including the externality of conventional power generation, the cost of the electric system is given of 27.6 ct·kWh^{-1} in a non-renewable energy system. Budischak et al. [15] optimized the least-cost combinations of intermittent renewable energies and storage technologies in a large regional grid in the Eastern USA. The aim is to supply the demand in this area. They found that when 290% of the demand is generated by the optimal combination of renewable energies and storage technologies, 99.9% of the hourly demand over four years can be covered. Depending on the chosen storage technology only 9–72 full load hours of storage technologies are required to fulfill the target value. Furthermore, regarding the technology costs by 2030, the renewable energy electricity system will be more cost-effective than the conventional one today.

In Europe, similar studies regarding the transformation process of the energy system were also carried out. Heide et al. [16] calculated the optimal mix of photovoltaics (PV) and wind power plants in a fully-renewable European power system to minimize three different objectives: storage capacities, balancing energy, and balancing power. According to their results, depending on the objectives, three different optimal solutions were found. To minimize the storage requirements, the mix of 60% wind and 40% PV has to be chosen when ideal roundtrip storage is used. Nevertheless, they do not take economic analysis into account. Pfenninger and Keirstead [17] combined three technologies, namely renewables, nuclear, and fossil fuels used in Great Britain's power system to reach different targets of CO_2 emissions reduction, energy security and system-wide levelized cost of electricity (LCOE). Their analysis showed that different combinations of the chosen technologies lead to similar results. From the perspective of renewables, a proportion of up to 80% relates to a significant increase of cost. However, a proportion above 80% asks for high investments in large-scale storage, imports of (renewable) power, or additional dispatchable renewables. Brouwer et al. [18] analyzed which flexibility options in the Western Europe power system should be used to minimize the total system costs 2050. These included demand response, natural gas-fired generators, interconnection capacity, curtailment of intermittent renewables, and electricity storage. With the exception of storage technologies, all flexibility options may reduce total system costs within varying proportions of renewable energies. Zakeri et al. [19] examined the technical and economic feasibility of flexibility options to integrate intermittent renewable energies in energy systems with a high proportion of non-flexible nuclear power generation. However, the role of biomass as a flexibility option and its impact on total system costs is not shown in detail, although, these plants are assumed as flexible as coal-fired power plants with carbon capture storage.

In Germany, based on a high proportion of biomass plants, several studies analyze their current and future role in the electricity system. Holzhammer [20] calculated that flexible power generation from biogas plants and biomethane CHPU might reduce total system costs in 2030. One reason is that it saved fuels and the lower numbers of start-stop operations, inter alia, by conventional power plants overcompensate additional costs for flexible power generation from biogas plants with a number of 4000 full load hours per year. In a previous study [21] we assessed the flexible biogas power generation using the average integration costs of surplus generation (AICSG) for the period of 2016–2035, which is defined as a quotient of remuneration and surplus generation. We find that biogas plants have to be as flexible as possible to smooth the future residual load curve and to reduce the further demand for flexibility options in Germany. Furthermore, the increasing extension of biogas plants may be more cost-effective for the system integration of intermittent renewable energies than their reduction or phase out. In another study for Germany, Eltrop et al. [22] calculated, endogenously, the installed capacities of lignite-, coal-, gas-fired power plants, biomass plants, and storage technologies using the European Electricity Market Model E2M2s. It is shown that varying the proportion of renewable energies (40%, 60%, and 80%) an endogenous extension of the installed capacity of flexible biomass plants can reduce the total electricity system costs. The annual amount of electricity generated by biomass plants is set to be constant. Due to saved investments in storage technologies and conventional power plants, regarding a proportion of 80% of renewable energies, flexible biomass plants reduce the total electricity system costs by 419 million € (compared to baseload generation).

To summarize, the above-mentioned studies show the impact of renewable energies on total system costs or the demand for further technologies to balance demand and supply, which become more important during the energy transformation process. The future role of flexible power generation from biomass plants is especially analyzed in German publications. Nevertheless, the impact of varying biogas extension paths exogenously by policy makers on the composition of flexibility options and the total costs in the future German electricity system is not taken into account in previous publications. In contrast to the endogenous optimization of flexibility options, e.g., in [18], the installed capacity of Germany's biogas plants is set by the EEG based on the decision of the German Government. Furthermore, according to the EEG revised in 2016 [4], details of the flexible biogas power generation are given by policy makers. For example, the power quotient PQ [9] which is defined as the quotient of installed and rated capacity—the annual average of electricity generation—of biogas plants has to be 2 or higher (EEG 2017, § 44b). With regard to the transformation process of the energy system towards renewable energies, the future role of flexible power generation from biogas plants determined exogenously by policy makers has to be assessed. In addition to other flexibility options, biogas plants might be one cost-effective option to integrate intermittent renewable energies into Germany's energy system.

In this paper, we assess the composition of flexibility options and the total costs in the German electricity system for the period of 2016–2035 by using a non-linear optimization model varying the extension path and mode of operation of biogas plants.

The objectives can be defined as follows:

i. To analyze the impact of varying proportions of biogas plants on the required power generation from conventional power plants;

ii. To minimize the residual load demand by the optimization of flexible power generation from biogas plants; and
iii. To examine the effect of flexible power generation from biogas plants on the total costs of the electricity system.

2. Methodology

With regard to the set objectives, we developed a method to describe the residual load curves with three biogas extension paths (Section 2.1), optimized the flexible power generation from biogas plants to reduce the demand for further flexibility options (Section 2.2), and minimized the total costs of the German electricity system for the period of 2016–2035 by using a non-linear optimization model (Section 2.3) taking into account representative days.

The following procedure is based on two significant simplifications. First, Germany's interconnecting capacities to neighboring countries were neglected. Consequently, demand and supply has to be balanced without the import and export of electricity. Second, the electricity system was described as a "copper plate", and the curtailment of regional electricity overcapacities and grid losses were not taken into account.

2.1. Selection of Representative Days and Calculation of the Residual Load Curve

In order to select representative days as an input for the optimization model, we used hourly feed-in data from wind and PV plants and the electricity consumption provided by the German transmission system operators [23] and the European Network of Transmission System Operators for Electricity [24] based on the year 2015. Following the methodology of [25], we normalized the hourly feed-in data from intermittent renewable energies and the electricity consumption according to their maximum annual value and used the clustering algorithm to select and weight representative days. In this study, we used four years (2020, 2025, 2030, and 2035) and seven representative days per year to minimize the total costs in the future electricity system. According to [26], a time resolution of 1 h for balancing demand and supply in an electricity system with high proportions of intermittent renewable energies was considered. As a consequence, 672 time slices were used as input data for the optimization of flexible power generation from biogas plants and the minimization of total costs.

2.2. Biogas Extension Paths and Calculation of the Residual Load Curve

Residual load is defined here as the electricity consumption minus the generation by intermittent renewable energies. To calculate the residual load curves for the years considered, we took into account the normalized hourly data of the representative days and increased the installed capacities of intermittent renewable energies. According to [21], we defined three biogas extension paths and calculated the installed capacity and electricity amount of renewable energies:

- Biogas phase out: After their remuneration period of 20 years, biogas plants will start to close down and will phase out in the 2030s.
- Biogas back up: 75 MW of biogas plants will be installed each year. However, due to the closure of existing biogas plants, the installed capacity will decrease to 1500 MW in 2035.
- Biogas increase: The annual deconstruction of existing biogas plants will be taken into account and the installed capacity of biogas plants increased by 100 MW each year for the period of 2016–2035.

To compare the extension paths with each other, the installed capacity and electricity amount of onshore wind plants were adapted to the electricity generated by biogas plants. As a consequence, the proportion of wind onshore plants in extension path biogas *phase out* has to be higher compared to *biogas increase* (Figure 1). The net electricity consumption (543.6 $TWh \cdot a^{-1}$, Scenario B 2025/2035 [27]) and the generated electricity by biomass (without biogas), hydropower, and other renewables were set to be constant for the period considered (Table 1). Details of the methodology are given in [21].

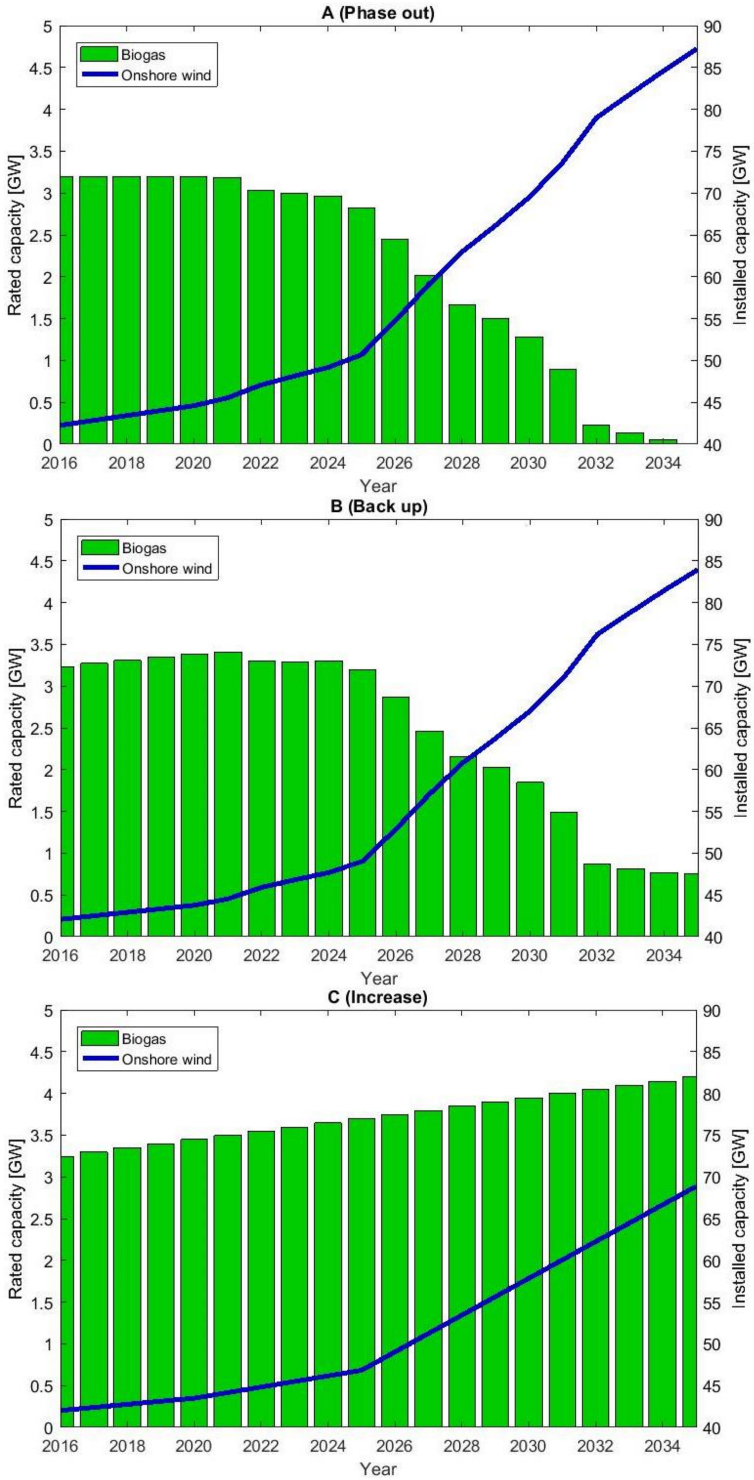

Figure 1. Installed capacities of onshore wind and rated capacities of biogas plants varying the biogas extension paths: biogas phase out (**A**); biogas back up (**B**); and biogas increase (**C**).

Table 1. Installed (wind and PV) and rated capacity of renewable energies in each biogas extension path [GW] (own assumptions and references).

Renewable Energy	2016	2020	2025	2030	2035	References
Offshore wind	3.9	6.5	11.0	15.0	19.0	[28–30]
PV	41.2	47.3	54.9	57.4	59.9	[27,29,31]
Hydropower			2.2			[29]
Biomass (without biogas)			1.2			[12]
Other renewables			1.3			[29]

2.3. Impact of (Flexible) Biogas Plants on the Residual Load

Flexible power generation from existing biogas plants requires investments in additional CHPU and/or biogas storage technologies, e.g., [8,9]. When biogas production is set to be constant, CHPU capacities above the average biogas production tolerate to shift the power generation over a certain period. To increase the temporal flexibility of biogas plants, the biogas production can also be orientated on the expected power generation [32,33]. The flexible biogas production allows a longer temporal shift of electricity generation during the time of low electricity demand and a longer period of maximum electricity generation during the time of low electricity supply by intermittent renewable energies. For this purpose, according to [34] we took three plant configurations of existing and new biogas plants into consideration (Table 2): The electricity generated by biogas plants is set to be constant in the plant configuration *Base*. In plant configuration *Flex*, the biogas production is set to be constant and the electricity generation is flexible depending on the biogas storage capacity of the biogas plant. Whereas in *Flex+*, the biogas production and the electricity generation were defined to be flexible to increase the flexibility of biogas plants. When existing biogas plants reach a remaining period of 10 years of remuneration, biogas plants generate flexible power (see EEG 2017, § 50b). Otherwise these are in baseload operation (details see [34]).

Table 2. Biogas plant configurations (according to [34]). PQ = power quotient.

Plant Configuration	Flexible Biogas Production	PQ	Biogas Storage Capacity [1]	Full Load Hours per Year
Base		Baseload generation		
Flex		2	10	4380
Flex+	X			

[1] Biogas storage capacity is defined as quotient of storage capacity (m^3) and hourly biogas production ($m^3 \cdot h^{-1}$).

To optimize the flexible biogas generation, the model of [34] was used to smooth the residual load curve by using the following objective function:

$$\min f\left(\{p_t\}_t^T \middle| \{r_t\}_t^T\right) = \sum_t (r_t - p_t)^2 \quad (1)$$

where p_t is the power generation from biogas plants and r_t is the residual load at each time t over the period T. All details of the model are described in [34].

The optimization was done for each biogas plant configuration and extension path, combining the scenarios considered [34] (Table 3). The residual load curves for each scenario for the period of 2016–2035 were used as inputs for the non-linear optimization model.

Table 3. Scenarios based on biogas extension paths and plant configurations [34].

Biogas Extension Path	Plant Configuration	Scenario
Increase	*Base* (B)	INC-B
	Flex (F)	INC-F
	Flex+ (F+)	INC-F+
Back up	*Base* (B)	BU-B
	Flex (F)	BU-F
	Flex (F+)	BU-F+
Phase out	*Base* (B)	REF

To assess the increasing proportion of biogas plants and their flexible power generation the impact *I*, defined as the rooted absolute difference between the reference scenario *REF* and the scenarios considered *SCEN*, were calculated over the period *T* [34] (Equation (2)):

$$I(f) = \sqrt{f(REF) - f(SCEN)} \tag{2}$$

2.4. Minimizing the Total Costs of the Electricity System in Varying Biogas Scenarios

In order to minimize the total costs in the future electricity system a non-linear optimization model is used which simultaneously optimizes the optimal hourly dispatch and the annual investments in conventional power plants and storage technologies. The installed capacity of nuclear, lignite, coal, and gas ([27], Scenario B 2025/2035) is predetermined exogenously for the period of 2016–2035. With regard to the optimal hourly dispatch in each hour and the total costs minimization, the model optimizes, endogenously, additional investments in flexible gas turbines, pumped-storage plants, and battery storage technologies (lithium ion) for balancing demand and supply of the residual load curve including electricity generation from biogas plants. Technical and economic data of storage technologies, such as round-trip efficiency or investments and marginal costs, were also predetermined exogenously.

Most of the operational power system and long-term energy system planning models are represented by linear problems [35], e.g., PLEXOS [36] or TIMES [37]. However, to focus on the time component of costs and benefits within a period of 20 years, we used a non-linear optimization model discounting the interest of all investments and marginal costs. Furthermore, we combined the hourly dispatch of operational power system models by simplifications, as well as the reduction of time slices by representative days and the consideration of 20 years that is part of long-term energy system planning models. The model was implemented in MATLAB (R2016b) using the interior-point algorithm (fmincon). Details of the model are given in the following equations and inequalities.

$$\min \sum_t \frac{\left(\sum_{exist}\left(mc_{exist,t} \times \sum_h p_{exist,h,t}\right) + \sum_{new}\left(mc_{new,t} \times \sum_h p_{new,h,t} + cc_{new,t} \times req_{new,t}\right)\right)}{\left(1+i_{soc}\right)^t} \tag{3}$$

Subject to

$$RL_{h,t} - p_{exist,h,t} - p_{new,h,t} \leq 0 \ \forall h, t, exist, new \tag{4}$$

$$req_{stor,t} = cap0_{stor} + \max\{cap0_{stor}; req_{stor,t}\} \ \forall t, stor \tag{5}$$

$$req_{GT,t} = \frac{\max\{req_{GT,t=1}; req_{GT,t}\}}{av_{GT}} \ \forall t \tag{6}$$

$$minP \leq p_{conv,h,t} \leq maxP \times av_{conv} \quad \forall h, t, conv \tag{7}$$

$$\left|p_{exist,h,t} - p_{exist,h-1,t}\right| \leq \Delta P \ \forall h, t, exist \tag{8}$$

$$0 \leq fl_{stor,h,t} \leq maxSC_{stor} \ \forall h, t, stor \tag{9}$$

$$fl_{stor,h,t} = fl0_{stor} + fl_{stor,h-1,t} + p_{storin,h,t} \times \eta - p_{storout,h,t} \; \forall h,t,stor \quad (10)$$

$$\sum_h p_{storin,h,t} \times \eta_{stor} = \sum_h p_{storout,h,t} \; \forall t,stor \quad (11)$$

$$p_{storout,h,t} \leq req_{stor,t} \times CF \; \forall h,t,stor \quad (12)$$

$$\sum_h p_{exist,h,t} \times FGHG_{exist,t} + p_{GT,h,t} \times FGHG_{GT,t} + \sum_h p_{renew,h,t} \times FGHG_{renew} \leq maxGHG_t \;\; \forall t, exist, renew \quad (13)$$

In the objective function (Equation (3)), total costs of existing and new installed conventional power plants, as well as storage technologies, were minimized for the exemplary years and discounted by a social discount rate i_{soc}. The annual total costs (capital costs cc_t and marginal costs mc_t) between the exemplary years taken into consideration were set to be the same as in the exemplary year before. However, these costs were discounted depending on the year t. Intermittent renewable energies are characterized by marginal costs close to zero. The residual load $RL_{h,t}$ has to be supplied by the technologies considered in each hour at time h and surplus generation is allowed to occur (Equation (4)). In addition to existing storage technologies $cap0_{stor}$, the model allows investments in additional capacities $req_{stor,t}$ (Equation (5)). The installed capacity of gas turbines was endogenously optimized, regarding to their average availability av_{conv} (Equation (6)). Furthermore, the power generation by conventional power plants was constrained by the minimum level of power generation $minP$, the installed capacity $maxP$, the average availability of conventional power plants av_{conv} (Equation (7)) and the hourly load change rate ΔP (Equation (8)). In contrast to conventional power plants, the model allows investments in new storage capacities and, therefore, the maximum storage capacity is exclusively restricted to the extension potential of storage technologies $maxSC$ (Equation (9)). In addition, the overall efficiency η of storage technologies was taken into consideration by the charging process $p_{STORin,h,t}$ (Equation (10)). Due to the consideration of weighting factors and representative days, the annual sum of discharged and charged electricity from storage technologies has to be identical (Equation (11)). The maximum discharging rate is defined as the product of the installed capacity $req_{STOR,t}$ and the C-factor CF (maximum discharging power relative to its maximum capacity) (Equation (12)). According to the German GHG target values of reduction in the energy system [3], the annual sum of conventional and renewable GHG emissions was restricted by parameter $maxGHG_t$ (Equation (13)). GHG emissions by renewable and conventional power plants including biogas plants were calculated by using GHG emission factors $FGHG$ [38,39]. Annual total costs were linearly interpolated between the selected years; with the exception of the years 2016–2019, those annual costs were set to be identical with the year 2020.

Exogenous economic data and the installed capacity of conventional power plants, as well as the maximum annual GHG emissions are described in Tables 4 and 5. A comprehensive overview of sets, indices, parameters, variables, and assumptions are given in the Appendix A (Tables A1 and A2).

Table 4. Capital and marginal costs of conventional power plants and storage technologies.

Technology	2016	2020	2025	2030	2035	Source
Capital costs (annuity [1]) (10^3 €·MW^{-1})						Own calculations according to
Li-ion batteries	149.4	132.6	112.4	96.5	88.8	[40–43]
Pumped-storage plants	114.0	118.8	125.3	132.2	139.8	[44–46]
Gas turbines	38.8	40.5	42.8	45.3	48.0	[47]
Marginal costs (€·MWh^{-1})						
Nuclear	10.6	10.7	-	-	-	
Lignite	16.1	21.7	28.6	33.6	38.5	
Coal	32.9	39.7	48.1	52.9	57.7	[38,43,48–55]
Gas	48.5	60.1	74.7	78.7	82.7	
Gas turbines	62.2	77.3	95.9	100.6	105.2	
Li-ion batteries	2.1	2.2	2.4	2.6	2.8	[44]
Pumped-storage plants	1.5	1.6	1.7	1.8	2.0	[43]

[1] The annuity was calculated by a discount rate of 6.4%. Life time of Li-ion batteries are 15 years (converter) and five years (battery), respectively; of pumped-storage plants are 60 years and of gas turbines are 50 years. Capital costs include the residual value at the end of the year 2035.

Table 5. Exogenous installed capacities of conventional power plants and restricted maximum GHG emissions per year. Missing intermediate values were calculated by linear interpolation.

Technology	2016	2020	2025	2030	2035	Source
Installed capacity (MW)						
nuclear	10,793	8107	0	0	0	
lignite	20,901	17,212	12,600	10,850	9,100	[27,56]
coal	28,661	25,612	21,800	16,400	11,000	
gas			28,466			[56], own assumptions
Maximum GHG emissions (10^9 t·CO_2e·a^{-1})	331.9	279.6	227.3	175.0	137.1	[3]

2.5. Sensitivity Analysis

We conducted a sensitivity analysis to show the impact of the different parameters on the total system costs, the investments in flexibility options and the utilization of conventional power plants. To do so, we varied the annuity of lithium-ion batteries, pumped-storage plants, as well as gas turbines, the social discount rate (−40/+40%), and the price of CO_2 per ton (+40/+80%). To calculate the marginal costs of the conventional power plants (Table 4), CO_2 prices of 7.6 €·t^{-1} (2015), 21 €·t^{-1} (2025), and 31 €·t^{-1} (2035) were taken into account [27,48]. Missing values were calculated by linear interpolation.

3. Results

3.1. Seven Representative Days

The algorithm chooses seven representative days given by the electricity consumption and generation by intermittent renewable energies based on the year 2015. As a result, the representative days and the weighting factor of these days are presented in Table 6. In according to the cluster size of the selected representative days, the weighting factor ensures that extreme days are not overrepresented in the optimization.

Table 6. Selected representative days (in ascending order) and weighting factors for the optimization.

Selected Representative Day	Weighting Factor
89	30
105	73
188	80
190	33
311	60
322	36
324	53

3.2. Impact of Biogas Plants on the Residual Load Curve

In all scenarios, the increasing proportion of biogas plants in the future renewable energy portfolio and their flexible power generation smooth the residual load curve for the period considered; consisting of four selected years (Table 7). Compared to the phase out of biogas plants in the future electricity system, an increasing proportion of biogas plants smooths the residual load curve. Without the flexibility of biogas plants, the substitution of onshore wind plants by baseload biogas plants also smooths the residual load curve in both extension paths characterized by an increasing proportion of biogas plants. Nevertheless, the residual load curve becomes smoother when the electricity generation by biogas plants is flexibilized. In the biogas extension paths *back up* and *increase*, the combination of flexible electricity generation and gas production achieves the best results. The smoothing effect is impacted to the largest extent in the scenario INC-F+ when the proportion of biogas plants are increasing and the gas production is flexibilized. This is why the flexible gas production is allowed to shift the electricity generation and to stop them over a longer period of positive and negative residual load, respectively.

Table 7. The summed impact of biogas plants on the residual load curve for the years 2020, 2025, 2030, as well as 2035 and the defined scenarios (10^3 MWh).

Biogas Extension Path	Scenario	Impact
Back up	BU-B	474.8
	BU-F	1080.9
	BU-F+	1184.6
Increase	INC-B	1014.3
	INC-F	1621.9
	INC-F+	1750.1

In the extension path *back up*, the impact varies between 474.8 and 1184.6 $\times$ 10^3 MWh over the years 2020, 2025, 2030, and 2035. In scenario BU-F, the flexible electricity generation from biogas plants impact is calculated to be 1080.9 $\times$ 10^3 MWh, which are more than two times higher than in the baseload electricity generation (BU-B). When the gas production is also flexibilized, the smoothing effect is increasing to 1184.6 $\times$ 10^3 MWh (BU-F+). The results of extension path *increase* are of similar characteristic as the ones given in biogas extension path *back up*. The higher the flexibility from biogas plants the higher the impact on the residual load curve. Due to a higher proportion of dispatchable biogas plants compared to intermittent onshore wind plants, the impact is increased up to 1750.1 $\times$ 10^3 MWh. To conclude, flexible power generation from biogas plants increase this effect, though, the marginal benefit of additional biogas plants in the electricity system is decreasing when their proportion becomes higher.

3.3. Impact of Biogas Plants on the Future German Electricity System

3.3.1. Impact of Biogas Plants on the Total Costs in the Electricity System

Depending on the impact of varying extension paths and modes of operations of biogas plants on the residual load curve, different total costs were optimized in the scenarios (Table 8). The highest total costs occur in the extension path *phase out*. The summed and discounted annual costs are about 127.35 $\times$ 10^9 € for the period considered. An increasing proportion of biogas plants in the future German electricity system decreases the total costs, without taking the costs of biogas plants into account. In the extension path back up, the total costs vary between 127.10 and 125.68 $\times$ 10^9 € and are comparably lower than the reference scenario. Furthermore, the results indicate that biogas plants should operate as flexibly as possible to decrease the total costs. The lowest results within the extension paths were achieved in the *Flex+* mode of operation (BU-F+ and INC-F+). Overall, the lowest total system costs were calculated in the extension path with the highest rate of construction of new biogas plants (*increase*). In the scenario INC-F+, the total costs were the lowest characterized by 124.52 $\times$ 10^9 €. The highest total costs were calculated in the baseload mode of operation (INC-B).

As analyzed in Section 3.2, the marginal utility in the extension path with the lower construction of new biogas plants (extension path *back up*) is higher than in the extension path *increase*. This results from the fact that the majority of existing biogas plants starts to close down between 2025 and 2030 (see Figure 1). Consequently, the differences of the installed capacities of biogas plants and the discounted annual costs in the scenarios start to become significant from the year 2030 onwards (Figure 2). As a result, if the costs of biogas plants are taken into consideration, the costs of additional biogas plants in the extension path *increase* might be higher than their additional benefit, taking the period of 2016–2035 into account.

Table 8. The total costs in the electricity system for the period 2016–2035 and scenarios defined (10^9 €).

Biogas Extension Path	Scenario	Total Costs
Phase out	REF	127.353
Back up	BU-B	127.099
	BU-F	125.929
	BU-F+	125.677
Increase	INC-B	126.273
	INC-F	124.654
	INC-F+	124.524

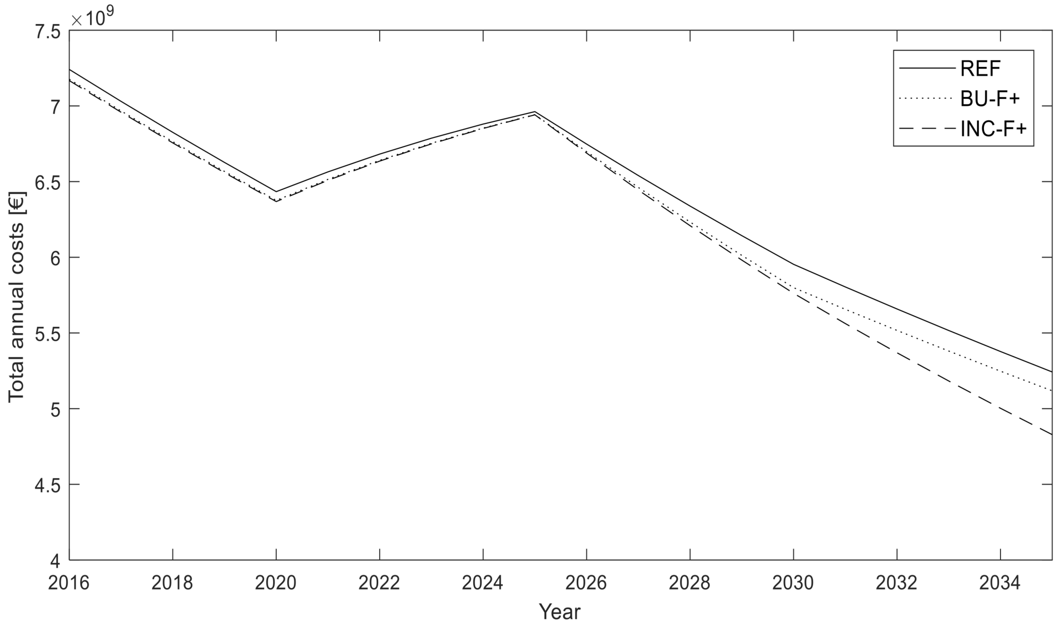

Figure 2. Discounted total annual costs of conventional power plants and storage technologies in the scenarios REF, BU-F+, and INC-F+ and the period considered.

The differences of discounted total annual costs can be explained by two reasons: the impact of biogas plants on (i) the demand for additional flexibility options and on (ii) the utilization of conventional power plants.

3.3.2. Impact of Biogas Plants on the Demand for Additional Flexibility Options

In general, the increasing proportion of biogas plants, especially their flexible power generation, decreases the demand for additional flexibility options (Table 9). Under the assumptions considered, in all scenarios (with the exception of REF, BU-B, and INC-B) the installed capacities of conventional power plants and existing storage technologies will be sufficient until the end of the 2020s. In the reference scenario, the phase out of biogas plants leads to the investment of additional pumped-storage plants and gas turbines in the year 2030. Similar results are achieved in the scenarios BU-B and INC-B. In all other scenarios, additional flexibility options are required (significant) starting from the year 2035 onwards. According to the achieved results, an increasing proportion of biogas plants substitutes the demand of Li-ion batteries and gas turbines in the future electricity systems. Pumped-storage plants are the cheapest solution to provide flexibility, therefore, the investments in pumped-storage plants were maximized by the optimization model. In our calculations, we allowed a maximum additional capacity of 4710 MW of pumped-storage plants; due to geographic circumstances, their potential is limited. Consequently, in all scenarios, the potential of pumped-storage plants was utilized and more cost-intensive flexibility options were substituted by biogas plants. As a result, there is no impact of varying biogas extension paths on the demand for additional flexibility options in the 2020s.

Table 9. Accumulated additional installed capacities of flexibility options in the electricity system for the years and scenarios defined (MW).

Scenario	Pumped-Storage				Li-ion				Gas Turbine			
Year	2020	2025	2030	2035	2020	2025	2030	2035	2020	2025	2030	2035
REF	0	0	745	4710	0	0	3	1218	0	0	949	949
BU-B	0	0	660	4710	0	1	3	1040	0	0	758	758
BU-F	0	0	0	4710	0	0	0	770	0	0	0	278
BU-F+	0	0	0	4710	0	0	0	660	0	0	0	389
INC-B	0	0	0	4710	2	2	4	83	0	1	20	20
INC-F	0	0	0	4710	0	1	1	3	0	0	1	1
INC-F+	0	0	0	4709	0	1	1	2	0	1	1	1

3.3.3. Impact of Biogas Plants on the Utilization of Conventional Power Plants and GHG Emissions

In addition, an increasing proportion of (flexible) biogas plants reduces the demand of conventional power plants, which are characterized by comparable high marginal costs. In Table A4 (see Appendix A) the utilization of conventional power plants and storage technologies is shown. Compared to the reference scenario, biogas plants reduce the utilization of coal-fired and gas-fired power plants and increase the supply of baseload generation power plants (nuclear or/and lignite). This effect is also shown in Figure 3. The increasing proportion and flexible power generation from biogas plants smooths the residual load curve and baseload generation power plants are better utilized. However, lignite-fired power plants have the highest GHG emissions and increasing full load hours lead to additional GHG emissions. In this study, we took annual maximum GHG emissions into account. Therefore, the utilization of lignite-fired power plants with low marginal costs is limited and the GHG emissions are similar or identical, respectively, in all scenarios (Table A5).

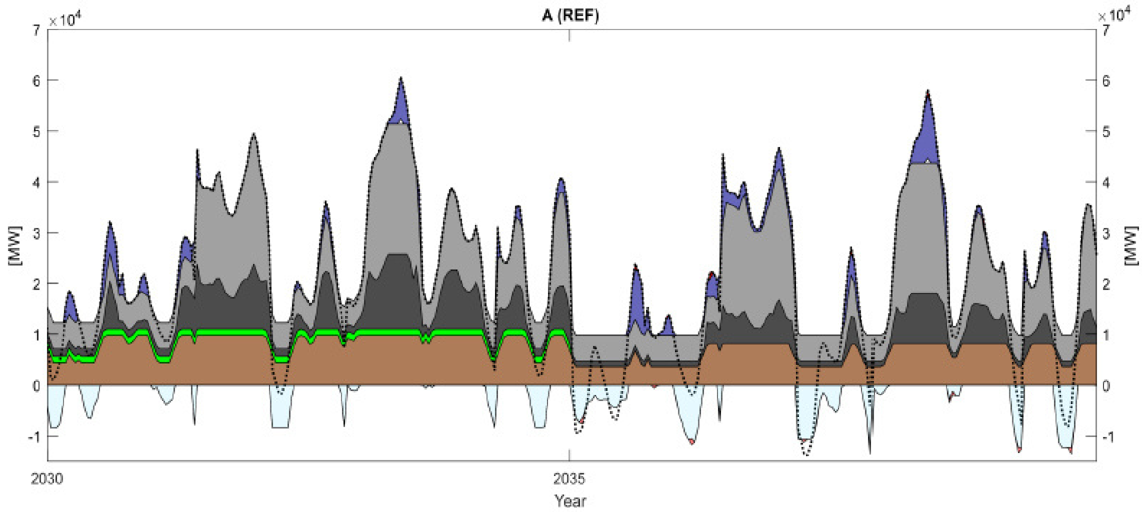

Figure 3. *Cont.*

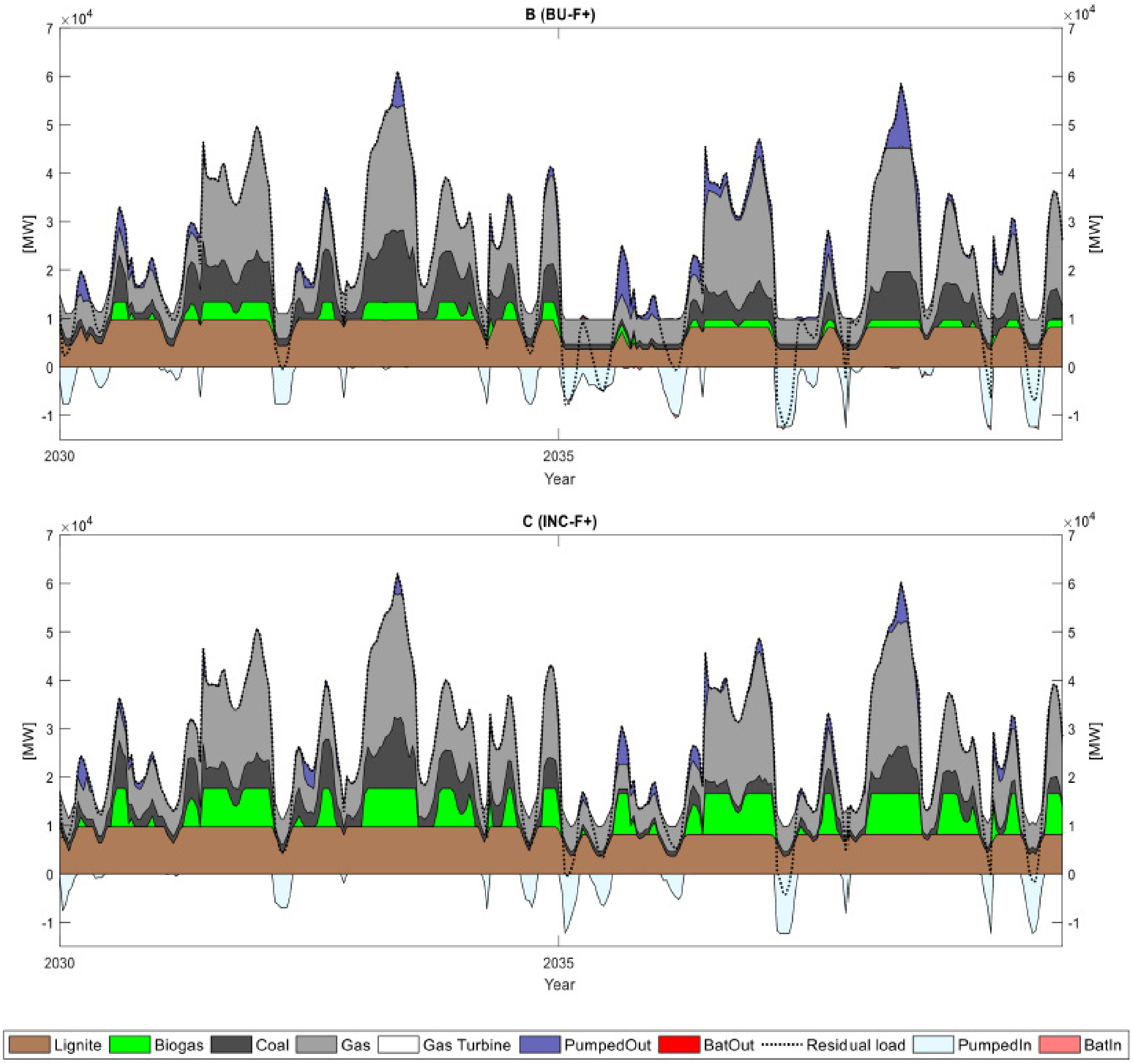

Figure 3. Residual load, biogas, and conventional electricity generation, as well as the operation of the storage technologies in the years 2030 and 2035 in the scenarios REF (**A**); BU-F+ (**B**) and INC-F+ (**C**). PumpedOut: discharged electricity from pumped-storage plants. BatOut: discharged electricity from Li-ion batteries. PumpedIn: charged electricity in pumped-storage plants. BatIn: charged electricity in Li-ion batteries.

4. Discussion

4.1. Applied Methodologies

The assessment of future extension paths of renewable energies is often carried out by the consideration of selected years instead of a period. However, political decision-makers have to evaluate their investments in renewable energies according to the period that reflects the impact of economic decisions. Therefore, we considered a period of 20 years, which is consistent with the remuneration period of the EEG for renewable energies in Germany. Taking the period into account also allows identifying an advantageous time of the investment and prevents early investments in technologies, e.g., characterized by a high cost-reduction. In addition, dispatchable biogas plants are associated with a higher LCOE compared to intermittent renewable energies or flexibility options, such as battery storage. Nevertheless, the LCOE does not typically consider the total system costs of system integration of intermittent renewable energies by using flexible conventional power plants or other technological solutions. Comparing storage technologies with biogas plants, the costs and time of energy supply by conventional or renewable energies also have to be taken into account. Consequently, the total system costs are a more appropriate approach to assess the proportion of biogas plants in the future renewable energy portfolio and their dispatchable power generation.

In addition, compared to the results of [22] we also showed that flexible power generation from biogas plants reduces the total costs in the German electricity system. However, they compared the total system costs between baseload and endogenously-optimized flexible power generation from biomass plants while the electricity was set to be constant, whereas in this paper, the proportion of biogas plants in the future electricity system was varied. In addition, we defined the design of the flexible biogas plants exogenously. Nevertheless, regarding the total system costs, the economic feasibility of flexible power generation from biogas plants compared to their baseload operation cannot yet be finally assessed. To do so, the marginal and capital costs of the renewable energies in all extension paths have to be used for a cost-benefit analysis in the period considered.

4.2. Discussion of Limitations

Germany was simplified as a "copper plate", losing energy by grid bottlenecks or the curtailment of renewable energies were neglected. However, the curtailment of wind energy has been increasing since 2009 [57] and the German government decided to limit the extension of wind power plants concentrated in the north of Germany (EEG 2017, § 36c). In addition, the requirement for flexibility options in the future electricity was overestimated. The import and export of electricity to neighboring countries smooths the residual load curve and was not taken into account. In general, the demand for dispatchable power plants can be considered as conservative.

In this paper, the current framework for the energy sector was taken as a basis. This regards the future expansion of renewable energies and the energy demand in the above mentioned period. Though, the framework conditions can be subject to a rapid change, as shown in the past amendments of the EEG, e.g., the shift from feed-in tariffs determined by the German government towards a tendering system. In the same way, according to the set goals of the German Climate Action Plan and the future electrification of the mobility and heating sector, the extension paths of renewable energies has to be increased by the German government in a timely manner for a decarbonization of the energy system until the year 2050. As a result, the demand for flexibility options is growing more rapidly than considered in this study. In addition, due to the increasing electrification of the heating and mobility sector (sector coupling), as well as advanced intermittent renewable energies, e.g., weak wind turbines, the future electricity demand and supply curve may be subject to change. Despite increasingly efficient electricity use, the overall demand may be higher than forecasted by the German transmission system operators. According to the renewable energy extension target values, an increasing electricity demand leads to a higher extension of (intermittent) renewable energies that have to be balanced by additional flexibility options.

Biogas plants are generating flexible electricity to decrease the demand for conventional power plants and storage technologies. Nonetheless, cost-intensive flexibility of small biogas plants using mainly manure and additional technical efforts could limit the flexible power generation in order to integrate intermittent renewable energies. However, small biogas plants using manure are characterized by additional benefits, such as low GHG emissions [58] and lower external costs. In summary, biogas plant operators will maximize their return on investment and the benefit from dispatchable renewable energies will be lower than that considered in this study. Last, electricity generation from biogas plants was compared with marginal costs and investments in conventional power plants, Li-ion batteries, and pumped-storage plants by using representative days. Power-to-gas can be also one option for the seasonal storage of intermittent renewable energies; though, the use of representative days does not allow the consideration of seasonal storage technologies. However, due to the low surplus generation in the period considered, power-to-gas becomes more important in electricity systems characterized by a higher proportion of intermittent renewable energies.

4.3. Optimal System Contribution of Biogas

In our calculations, the biogas extension path *back up* achieved a higher marginal utility than the biogas extension path *increase*. Furthermore, in the extension path *back up*, the installed capacity of biogas plants is 1.500 MW and they contribute to 1.2% of Germany's net electricity consumption in the year 2035 (6.6 TWh). The annual baseload operation of other biomass plants is about 10.6 TWh. In addition, the installed capacity of biogas plants in the extension path *back up* is based on the study of Repenning et al. [59], who calculated the installed capacity of biogas plants in 2035 to achieve the ambitious GHG reduction target in Germany of 95% by 2050 compared to the reference year 1990. In other publications, a higher amount of electricity generated by biogas plants is taken into account. For example, Eltrop et al. [22] considered an annual electricity generation from biogas plants of 46 TWh in all scenarios characterized by a proportion of 40%, 60%, and 80% of renewable energies, whereas Holzhammer [20] based his calculations of flexible electricity generation from biogas plants on an annual electricity amount between 30.5 and 52 TWh in 2030. Schill [60] took flexible electricity generation from biomass plants of 59 $TWh \cdot a^{-1}$ into consideration and calculated the storage demand in Germany in 2032 and 2050. Greenpeace [61] analyzed Germany's electricity and heating sectors based on 100% renewable energies in the year 2050; they took an annual (flexible) electricity generation from biomass plants of 45 TWh into account. To summarize, an increasing system contribution of biogas plants, which was examined in the biogas extension path *increase*, achieved a comparable lower decrease of the total annual costs in Germany's electricity system. Compared to the above-mentioned studies, the (flexible) electricity generation from biogas and biomass plants, respectively, considered in these studies is similar to the biogas extension path *increase*; characterized by an electricity generation from biogas plants of 36.8 TWh and 10.6 TWh from other biomass plants in baseload generation.

4.4. Sensitivity Analysis

In Table 10, we show the additional installed capacities of flexibility options depending on the parameter varied in the sensitivity analysis. In all cases, the investments in pumped-storage plants were unchanged, whereas, in three cases, different installed capacities of Li-ion batteries and gas turbines were needed to supply the electricity demand in the scenario BU-F+ and the year 2035. With the exception of increased Li-ion and decreased gas turbine capital costs, no additional investments in Li-ion batteries and/or gas turbines were made. The sum of both flexibility options was 1048 MW for all varied parameters. Furthermore, in all cases, varied parameters did not lead to significant changes of the utilization of conventional power plants. Although, the CO_2 price was increased by 80%, conventional power plants characterized by lower GHG emissions were not utilized more often.

Table 10. Results of the sensitivity analysis: additional installed capacities of flexibility options in the scenario BU-F+ and the year 2035.

Parameter		Pumped-Storage	Li-ion	Gas Turbine
Capital costs of	Li-ion (−40%)	4710	660	389
	Li-ion (+40%)	4710	0	1048
	Pumped-storage (−40%)	4710	116	933
	Pumped-storage (+40%)	4710	660	389
	Gas turbine (−40%)	4710	286	762
	Gas turbine (+40%)	4710	660	389
Social discount rate (−40%)		4710	660	389
Social discount rate (+40%)		4710	660	389
Price of CO_2 (+40%)		4710	660	389
Price of CO_2 (+80%)		4710	660	389

With regard to the total system costs, the variation of the annuity of flexibility options had a low effect on the results (Figure 4). The highest impact was achieved by the variation of the annuity of pumped-storage plants, whereas different social discount rates and the CO_2 prices (Figure 5) are characterized by a higher sensitivity and lead to significantly higher and lower total system costs, respectively.

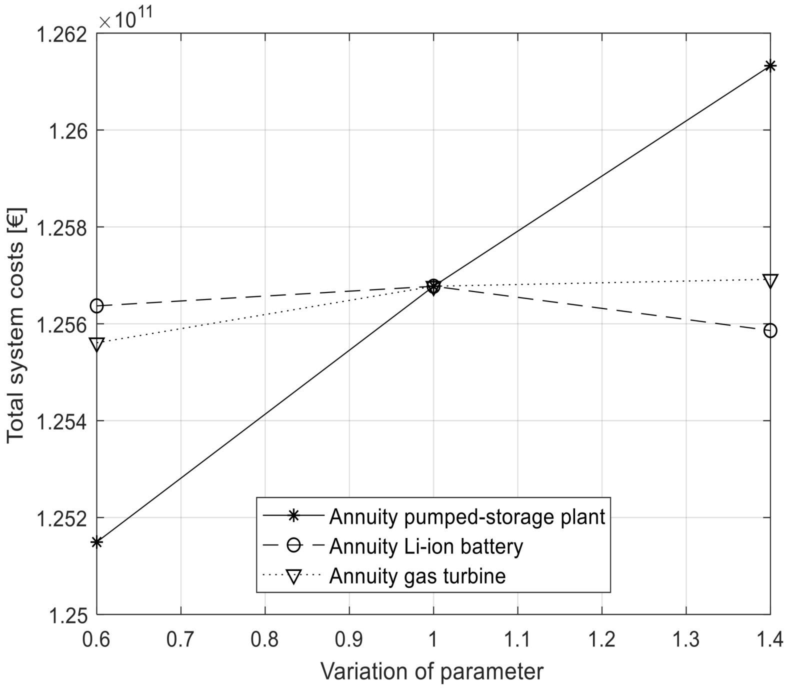

Figure 4. Results of the sensitivity analysis: impact of the varying annuity of pumped-storage plants, Li-ion batteries and gas turbines on the total system costs.

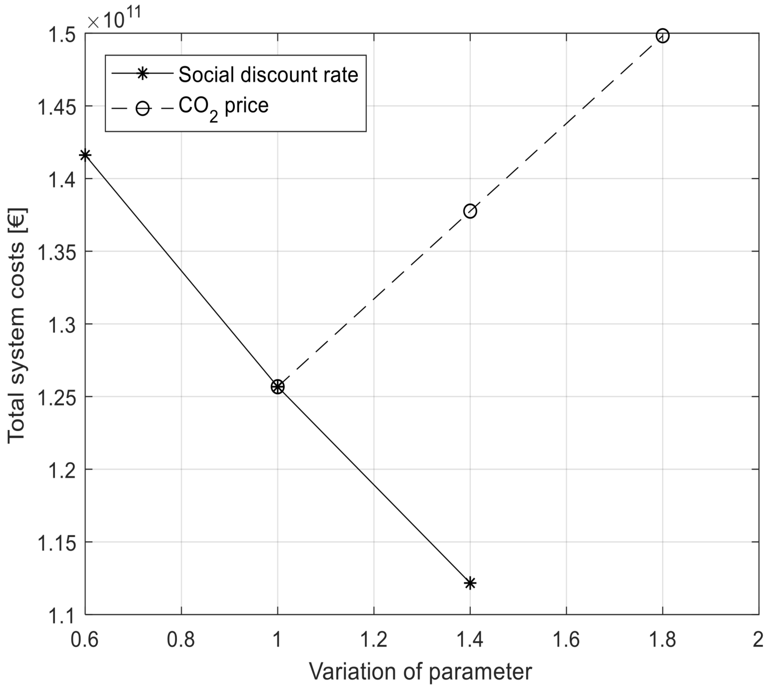

Figure 5. Results of the sensitivity analysis: impact of the varying social discount rate and CO_2 price on the total system costs.

5. Conclusions and Policy Implications

In this study, we analyzed the impacts of varying biogas plants extension paths, including Germany's existing biogas plants, and modes of operation on the total system costs in the period of 2016–2035 by using a non-linear optimization model. We found that an increasing proportion of (flexible) biogas plants in the future German electricity system reduces the demand of storage technologies and flexible conventional power plants to supply the demand. Without taking into account the capital and marginal costs of biogas plants, they can be a cost-effective flexibility option (compared to other technologies).

Firstly, the replacement of intermittent onshore wind capacities by dispatchable biogas plants smooths the residual load curve and reduces the demand for further flexibility options. Secondly, the operation of biogas plants should be as flexible as possible to increase the effect on the future residual load curve and the reduction of the total system costs. However, the findings underline that the biogas extension path *back up* may be a more economically feasible way to integrate intermittent renewable energies into the electricity system than the continuous increase in the extension path *increase*. Regarding the total costs, the marginal utility in the extension path *increase* was lower than in the extension path *back up* and emphasizes, under the assumptions considered, a constant increase of biogas plants may lead to additional system costs. Our model results specify that Germany's electricity system is characterized by sufficient capacities of flexibility and additional flexibility options are needed from about the year 2030 onwards. Thus, in the short-term, there is no need to implement further flexibility options when the extension paths of renewable energies and the decrease of the installed capacity of conventional power plants remain unchanged. However, due to Germany's ambitious GHG reduction target values and the goals of the Paris Agreement, the utilization and the installed capacity of lignite-fired, as well as coal-fired power plants have to be reduced more rapidly [62]. Furthermore, the decarbonization of the energy systems also requires the use of renewable electricity in the heating and mobility sectors [63], whereby extension of intermittent renewable energies should be further enhanced, compared to the defined annual increase of renewable energies in the EEG (EEG 2017, § 4). Depending on the capacities of conventional and renewable capacities, additional flexibility options may be needed before 2030. To summarize, based on the future extension paths of renewable energies and the installed capacity of conventional power plants, (flexible) biogas plants can be a cost-effective subset of future flexibility options to integrate intermittent renewable energies into the electricity system.

From the broader perspective of policymakers, we recommend the following strategies:

- The economic assessment of flexibility options in the electricity system has to include the interactions between these options and all conventional, as well as renewable energy provision technologies, within Germany's electricity system. From the year 2030 onwards, flexible power generation from biogas plants can be an option to decrease the total system costs in Germany's electricity system.
- The optimal installed capacity and mode of operation of biogas plants depends on the development of conventional and (intermittent) renewable energies in the future electricity system.
- To increase the market penetration of flexible power generation from biogas plants, additional market revenues are needed. This can be achieved by the reduction of conventional power plants in baseload operation.
- Due to the limited potential of biomass, the economic assessment of biomass use in the energy system should also be taken into account in different areas of application: e.g., the production of basic chemicals based on biomass might be necessary if GHG emissions are reduced up to 95% by 2050.

For further research, we suggest a cost-benefit analysis to finally assess the most cost-effective extension path and mode of generation of biogas plants in the future German electricity system. Therefore, the varying costs of the intermittent renewable energies and of biogas plants, respectively, in all scenarios have to be taken into account. A cost-benefit analysis would enable a comprehensive economic assessment that considers the discounted costs and benefits over the period considered.

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Author Contributions: Markus Lauer developed the optimization model, carried out the case study for Germany, and wrote the manuscript. Daniela Thrän supervised the work, contributed to the development of scenarios as well as to the conclusions, and co-wrote the work.

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Appendix A

Table A1. Sets, indices, parameters and variables considered in the optimization model.

Type	Range	Description	Unit, Instance
Sets and Indices			
$h \in H$		Time	Hours (per year)
$t \in T$		Time	Years
$exist \in EXIST$		Existing conventional and pumped-storage plants	Nuclear, lignite, coal, gas and pumped-storage
$new \in NEW$		Additional gas turbines and storage technologies	Gas turbines, pumped-storage and Li-ion batteries
$stor \in STOR$		Storage technologies	Pumped-storage and Li-ion batteries
$conv \in CONV$		Conventional power plants	Nuclear, lignite, coal, gas and gas turbines
Variables			
$fl_{stor,h,t}$	[0; SCstor]	Storage filling level	(MWh)
$p_{conv,h,t}$	[minP; maxP]	Hourly power generation from conventional power plants	(MWh)
$p_{GT,h,t}$	$R \geq 0$	Hourly power generation from gas turbines	(MWh)
$p_{storin,h,t}$	$R \geq 0$	Hourly charged electricity in storage technologies	(MWh)
$p_{storout,h,t}$	$R \geq 0$	Hourly discharged electricity by storage technologies	(MWh)
$req_{GT,t}$	$R \geq 0$	Required installed capacity of gas turbines	(MW)
$req_{stor,t}$	[0; maxSCstor]	Required installed capacity of storage technologies	(MW)
Parameters			
av_{conv}	[0; 1]	Average conventional power plant availability	
$cap0_{stor}$	$R \geq 0$	Initial installed capacity of storage technologies	(MW)
cc_{conv}	$R \geq 0$	Capital costs of conventional power plants	(10^3 €·MW^{-1}) , Table 4
cc_{stor}	$R \geq 0$	Capital costs of storage technologies	(10^3 €·MW^{-1}) , Table 4
CF_{stor}	$R \geq 0$	C-factor of storage technologies	
ΔP_{conv}	[0; 1]	Load change rate of conventional power plants	
η_{stor}	[0; 1]	Roundtrip efficiency of storage technologies	
$FGHG_{conv}$	$R \geq 0$	Emission factors of conventional power plants	(kg·CO_2e·MWh^{-1})
$FGHG_{renew}$	$R \geq 0$	Emission factors of renewable energies	(kg·CO_2e·MWh^{-1})
$fl0_{stor}$	$R \geq 0$	Initial filling level storage technologies	(MWh)
i_{ea}	[0; 1]	Discount rate of economic actors	
i_{soc}	[0; 1]	Social discount rate	
maxGHG	$R \geq 0$	Maximum annual GHG emissions in the electricity system	(10^9 t·CO_2e·a^{-1}), Table 5
$maxP_{conv}$	$R \geq 0$	Installed capacity of conventional power plants	(MW)
maxSC_{stor}	$R \geq 0$	Maximum potential of storage technologies	(MW)
mc_{conv}	$R \geq 0$	Marginal costs of conventional power plants	(€·MWh^{-1}), Table 4
mc_{stor}	$R \geq 0$	Marginal costs of discharging from storage technologies	(€·MWh^{-1}), Table 4
minP_{conv}	$R \geq 0$	Minimum power generation level	(MW)

Table A2. Assumptions on conventional power plants, storage technologies, and the rates of discount.

Parameter	Energy Source/Description	Value	Unit	Source/Note
av_{conv}	conventional power plants	0.9		own assumption according to [64]
$cap0_{stor}$	pumped-storage plants Li-ion	7600 0	(MW)	[46] own assumption
CF_{stor}	pumped-storage plants Li-ion	0.16 1		[65] [66]
ΔP_{conv}	nuclear lignite coal gas gas turbine	21 17 35 22 100	(% installed capacity h^{-1})	[67] [68]
η_{stor}	pumped-storage plants Li-ion	0.8 0.95		[43] [40,41]
$fl0_{stor}$	storage technologies	$0.5 \times cap0_{stor} \times h^{-1}$	(MWh)	own assumption
i_{ea}	discount rate of economic actors	0.064		According to German energy suppliers, e.g., [69]
i_{soc}	social discount rate	0.03		[70]
$maxSC_{stor}$	pumped-storage plants	12,310	(MW)	[46]
	Li-ion	15,000		own assumption
$minP_{conv}$	nuclear lignite coal gas	75 45 10 20	(% installed capacity)	[67]
	gas turbine	0		own assumption, no must-run operation due to increasing role of renewable energies

Table A3. Assumptions on emission factors of conventional and renewable power plants ($kg \cdot CO_2e \cdot MWh^{-1}$).

<table>
<tr><th>Parameter</th><th>Energy Source</th><th>2020</th><th>2025</th><th>2030</th><th>2035</th><th>Source/Note</th></tr>
<tr><td rowspan="10">$FGHG_{renew}$</td><td>PV</td><td colspan="4">55</td><td rowspan="4">[39]</td></tr>
<tr><td>onshore wind</td><td colspan="4">9</td></tr>
<tr><td>offshore wind</td><td colspan="4">4</td></tr>
<tr><td>hydropower</td><td colspan="4">3</td></tr>
<tr><td>other</td><td colspan="4">11</td><td>own calculations according to [39]</td></tr>
<tr><td>biomass</td><td colspan="4"></td><td></td></tr>
<tr><td>solid</td><td colspan="4">25</td><td rowspan="3">[39]</td></tr>
<tr><td>liquid</td><td colspan="4">316</td></tr>
<tr><td>biomethane</td><td colspan="4">157</td></tr>
<tr><td>biogas</td><td colspan="4">127</td><td>[71]</td></tr>
<tr><td rowspan="5">$FGHG_{conv}$</td><td>nuclear</td><td>0</td><td>-</td><td>-</td><td>-</td><td>own assumptions</td></tr>
<tr><td>lignite</td><td>1049</td><td>1036</td><td>1023</td><td>1010</td><td rowspan="4">own calculations according to [38,68,72]</td></tr>
<tr><td>coal</td><td colspan="4">892</td></tr>
<tr><td>gas</td><td colspan="4">404</td></tr>
<tr><td>gas turbine</td><td>518</td><td>511</td><td>505</td><td>499</td></tr>
</table>

Table A4. Utilization of the conventional power plants and the storage technologies in the scenarios and years considered. Furthermore, the annual surplus generation is shown. Values of storage technologies describe the discharged amount of electricity (TWh·a^{-1}). Values are rounded.

Year	Scenario	Nuclear	Lignite	Coal	Gas	Pumped-Storage	Li-ion	Gas Turbine	Surplus
2020	REF	63.57	130.43	75.05	45.38	9.77	0	0	0.01
	BU-B	63.49	130.97	74.65	45.34	9.94	0	0	0.09
	BU-F	63.57	131.80	73.36	45.04	7.67	0	0	0
	BU-F+	63.83	132.24	72.76	44.97	7.65	0	0	0
	INC-B	63.56	131.03	74.55	45.32	10.00	0	0	0.08
	INC-F	63.82	132.31	72.74	44.94	7.69	0	0	0
	INC-F+	63.82	132.90	72.19	44.94	7.87	0	0	0
2025	REF	0	95.85	96.50	84.36	2.65	0	0	0
	BU-B	0	96.01	95.54	85.13	2.47	0	0	0
	BU-F	0	97.56	93.52	85.61	2.53	0	0	0
	BU-F+	0	97.88	93.26	85.38	1.81	0	0	0
	INC-B	0	96.56	93.78	86.32	2.40	0	0	0
	INC-F	0	98.34	91.74	86.25	1.09	0	0	0
	INC-F+	0	97.56	92.88	85.74	0.49	0	0	0
2030	REF	0	75.77	54.17	105.20	7.72	0	0.05	1.37
	BU-B	0	76.28	52.58	105.99	7.40	0	0.04	1.15
	BU-F	0	77.35	51.95	104.73	6.09	0	0	0.61
	BU-F+	0	77.87	51.33	104.78	5.89	0	0	0.61
	INC-B	0	77.89	46.93	109.06	6.37	0	0.01	0.40
	INC-F	0	81.77	42.92	108.09	3.54	0	0	0
	INC-F+	0	82.05	42.55	108.19	3.61	0	0	0
2035	REF	0	57.88	32.49	108.66	14.26	0.46	0.05	7.75
	BU-B	0	58.26	31.45	108.12	14.08	0.40	0.04	6.58
	BU-F	0	57.91	32.54	106.60	13.63	0.47	0.02	5.89
	BU-F+	0	58.23	32.49	105.92	13.57	0.34	0.02	5.50
	INC-B	0	60.09	25.49	107.90	12.96	0.04	0	2.51
	INC-F	0	62.72	24.99	102.43	9.20	0	0	0.11
	INC-F+	0	65.88	21.05	103.24	9.29	0	0	0.11

Table A5. GHG emissions of the conventional power plants in the scenarios and years considered (10^9 t·CO_2e·a^{-1}). Values are rounded.

Year	Scenario	Nuclear	Lignite	Coal	Gas	Gas Turbine	Renewables	Sum
2020	REF	0	136.87	66.94	18.33	0	7.66	229.80
	BU-B	0	137.44	66.59	18.32	0	7.85	230.19
	BU-F	0	138.31	65.44	18.20	0	7.85	229.80
	BU-F+	0	138.76	64.90	18.17	0	7.85	229.68
	INC-B	0	137.49	66.50	18.31	0	7.92	230.22
	INC-F	0	138.83	64.89	18.15	0	7.92	229.79
	INC-F+	0	139.46	64.39	18.15	0	7.92	229.93
2025	REF	0	99.31	86.08	34.08	0	7.82	227.30
	BU-B	0	99.48	85.22	34.39	0	8.21	227.30
	BU-F	0	101.08	83.42	34.59	0	8.21	227.30
	BU-F+	0	101.41	83.19	34.49	0	8.21	227.30
	INC-B	0	100.04	83.65	34.87	0	8.73	227.30
	INC-F	0	101.89	81.83	34.84	0	8.73	227.30
	INC-F+	0	101.08	82.85	34.64	0	8.73	227.30
2030	REF	0	77.50	48.32	42.50	0.03	6.65	175.00
	BU-B	0	78.03	46.90	42.82	0.02	7.23	175.00
	BU-F	0	79.12	46.34	42.31	0	7.23	175.00
	BU-F+	0	79.65	45.79	42.33	0	7.23	175.00
	INC-B	0	79.67	41.86	44.06	0	9.41	175.00
	INC-F	0	83.64	38.28	43.67	0	9.41	175.00
	INC-F+	0	83.93	37.96	43.71	0	9.41	175.00
2035	REF	0	58.44	28.98	43.89	0.03	5.74	137.08
	BU-B	0	58.81	28.05	43.68	0.02	6.51	137.08
	BU-F	0	58.47	29.02	43.07	0.01	6.51	137.08
	BU-F+	0	58.79	28.98	42.79	0.01	6.51	137.08
	INC-B	0	60.67	22.73	43.59	0	10.08	137.08
	INC-F	0	63.32	22.29	41.38	0	10.08	137.08
	INC-F+	0	66.51	18.77	41.71	0	10.08	137.08

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Article 3

Economic assessment of flexible power generation from biogas plants in Germany´s future electricity system

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Economic assessment of flexible power generation from biogas plants in Germany's future electricity system

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A B S T R A C T

When integrating intermittent renewable energies in the electricity system, additional technologies are needed to ensure that a sufficient power supply is maintained. Alongside storage technologies and conventional power plants, dispatchable biogas plants are one solution for balancing demand and supply in energy systems with a high proportion of renewable energies. In this study, we conducted an economic assessment of the different extension paths and modes of operation of the biogas plants in Germany's future electricity system for the period of 2016–2035. This entailed carrying out a cost-benefit analysis that included the costs incurred for the flexibilization and installation of new biogas plants and the costs saved with respect to onshore wind turbines and additional saved opportunity costs. The results show that adding biogas plants in Germany's future electricity system –compared to their phase-out– requires cost reductions and/or has to be accompanied by further benefits in other sectors and areas to ensure economically feasible operation. Differentiated from a substantial growth, higher net present values were obtained in the extension path characterized by a low construction rate of new biogas plants. Furthermore, the economic feasibility of biogas plants benefits from an early phase-out of lignite- and coal-fired power plants.

1. Introduction

Germany's government passed a Climate Action Plan in 2016 to reduce the negative impact of climate change and to fulfill the goals of the Paris Climate Accord [1]. The Climate Action Plan defines maximum greenhouse gas (GHG) emissions by sector; in the energy sector, GHG emissions have to be reduced by 61–62% by 2030 over the reference year 1990 [1]. Consequently, the proportion of renewable energies, based on intermittent wind and solar plants, has to increase and conventional power plants with high GHG emissions have to be phased out [2,3]. The intermittency of the power supplied by wind and solar plants requires further technologies to balance demand and supply and to ensure there is a sufficient supply of power. Dispatchable biogas plants are one way to integrate intermittent renewable energies into the system in addition to storage technologies, demand side management (DSM), the extension of grid capacities and (flexible) conventional power plants, [4–7].

In 2016, about 8500 biogas plants were generating electricity and heat in Germany. Their installed capacity was about 4400 MW. Approximately 95% of all biogas installations are agricultural plants using mainly energy crops and manure for anaerobic digestion [8]. Furthermore, biogas plants made up 17.6% of Germany's electricity generation from renewables [9]. However, their comparably high levelized costs of electricity (LCOE)[1] prompted the German government to limit the future extension of biogas plants in Germany. The amendment to the Renewable Energy Sources Act of 2016 limits new installations to a maximum of 150 MW (2017–2019) and 200 MW (2020–2022) annually [10]. From 2004 to 2014 the average annual installation of new biogas plants was 350 MW [11] and these plants will start to phase out after their 20-year remuneration period. Thus, the installed capacity and generated electricity will begin to decrease from the mid-2020s onwards [12]. Likewise, the

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[1] The LCOE is defined as the costs over the lifetime divided by the electricity generated (see Appendix B).

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2016 amendment to the EEG requires that new biogas installations with an installed capacity of more than 100 kW have to be flexibilized (EEG 2017, § 44b) in order to improve the integration of wind and solar plants into the system. Furthermore, the 2012 amendment to the EEG implemented a flexibility premium that partially refinances additional investments in flexible power generation from existing biogas plants. For existing installations, the flexible power generation is not mandatory but more than one third of Germany's plants received the funding in mid-2017 [8]. In contrast to their baseload generation, biogas plants need a higher installed capacity of combined heat and power units (CHPU) and/or gas storage capacity in order to shift their energy generation [13,14]. The basic idea of flexible power generation from biogas plants is to decrease the power generation when the supply from intermittent renewable energies is high and/or the energy demand is low and to increase in the contrary case, respectively.[2] In this paper, we compare the total system costs of three extension paths and modes of operation for biogas plants in Germany's future electricity system.

Several studies have looked at the cost-efficient transformation of the energy system towards an increasing proportion of renewable energies in the electricity, heating and mobility sector. Steinke et al. [15] analyzed the interdependency of grid extensions and storage capacities in a 100% renewable European power grid. They found that the lowest overall system costs were achieved by using small decentralized battery storage units to decrease the demand for grid extension. However, in most scenarios, the demand for back-up capacities in a 100% renewable power system exceeds what biomass could potentially provide. Dale et al. [16] compared the total costs of two scenarios in the UK for the year 2020: A scenario where the electricity is generated mainly by coal and gas-fired power plants, and a scenario where 20% of the electricity is generated by wind farms. Without taking into account the external costs of conventional power plants, the total annual costs of the wind scenario were about 10.7% higher than the conventional scenario. Timilsina and Jorgensen [17] examined the overall supply costs for Romania's power generation with respect to a GHG emissions reduction. The additional discounted supply costs of the green scenario, with a higher proportion of renewable energies and lower GHG emissions (compared to the reference scenario), for the period of 2015–2050 were €3 billion, which is about 1% of the total supply costs. However, by 2030 GHG emissions were reduced by about 26% over 2005 levels in the green scenario compared to 16% by 2050 in the baseline scenario. In contrast, Nitsch [18] calculated the differential costs of a scenario based on renewable energies in order to decrease Germany's GHG emissions by 80% by 2050 (over 1990 levels). He underscored that, starting from 2023, differential costs will be negative and the extension of renewable energies will slowly become economically feasible.

The role of biomass in future energy systems is not analyzed in detail in the above-mentioned studies except for in the study by Ref. [18]. Scholz et al. [19] calculated the cost of the European power system by using the energy system model REMix and varying the proportion of intermittent renewable energies between 0 and 140%. Due to the high capital costs of biomass (and geothermal power) plants, those technologies were not considered in all scenarios. Jensen and Skovsgaard [20] showed the impact of CO_2 prices on the use of biogas in Denmark. The increasing price of CO_2 leads to higher system costs when the target for manure use is reached in 2025; however, if these prices become very high, biogas will represent a significant proportion of the energy mix and overall system costs will decrease.

In Germany, Eltrop et al. [21] endogenously optimized the installed capacity of biomass plants (the electricity generated by biomass was set to constant) in three scenarios with renewable energies making up 40, 60 and 80% of gross electricity consumption respectively. Total system costs were reduced by up to €419 million per year by flexibilizing biomass plants. Based on this analysis, Fleischer [22] optimized Germany's power plant portfolio by varying the proportion of renewable energies in order to reduce total system costs in different scenarios. He found that in scenarios with a high proportion of renewable energies, biomass plants reduce annual generation costs due to a substitution of other renewable energies and a reduction in investments in flexibility options and grid extensions, among other things. In a previous study [23], we analyzed the effect that varying biogas extension paths and modes of operation would have on Germany's future electricity system for the period of 2016–2035. Increasing the proportion of biogas plants (compared to phasing them out) reduced the demand for additional flexibility options and the utilization of conventional power plants with comparably high marginal costs and GHG emissions. Furthermore, compared to baseload generation in biogas plants, the highest impact was achieved through flexible power generation. However, a comprehensive economic assessment of (flexible) biogas plants in the German electricity system has yet to be conducted that includes the benefits and costs starting from the initial time of the investment until the target system is reached.

Therefore, in this paper, we use a cost-benefit analysis to assess economically different extension paths and modes of operation of biogas plants in the German electricity system for the period of 2016–2035.

The objectives were as follows:

i. To analyze the costs and benefits of varying biogas extension paths and modes of operation in the electricity system.
ii. To economically assess the biogas extension paths and modes of operation through the use of a cost-benefit analysis.
iii. To determine the biogas extension path and mode of operation with the highest economic benefit.

2. Methodology

2.1. Extension paths and modes of operation of biogas plants

Following [4,23], we considered three extension paths and modes of operation of biogas plants.

2.1.1. Biogas extension paths

In previous studies, we defined three biogas extension paths in Germany for the period of 2016–2035 [4,23]. In all biogas extension paths, the net electricity consumption was set to constant over the period under consideration and the extension of photovoltaic (PV) plants was taken into account following [24]. The extension of offshore wind turbines was based on the goals of the EEG 2017 [25]. Furthermore, future electricity generated by run-of-river power stations and other biomass plants was also set to constant. The renewable energy target values of the EEG are based on gross electricity consumption; e.g., renewable energies have to represent between 40 and 45% of gross electricity consumption by 2025, and 55 and 60% by 2035 (EEG 2017, § 1).[3] Consequently, depending on

[2] Further details on the principles of flexible power generation from bioenergy are presented in Ref. [6].

[3] Based on the coalition agreement of Germany's current government, this target value has been increased to 65% by 2030.

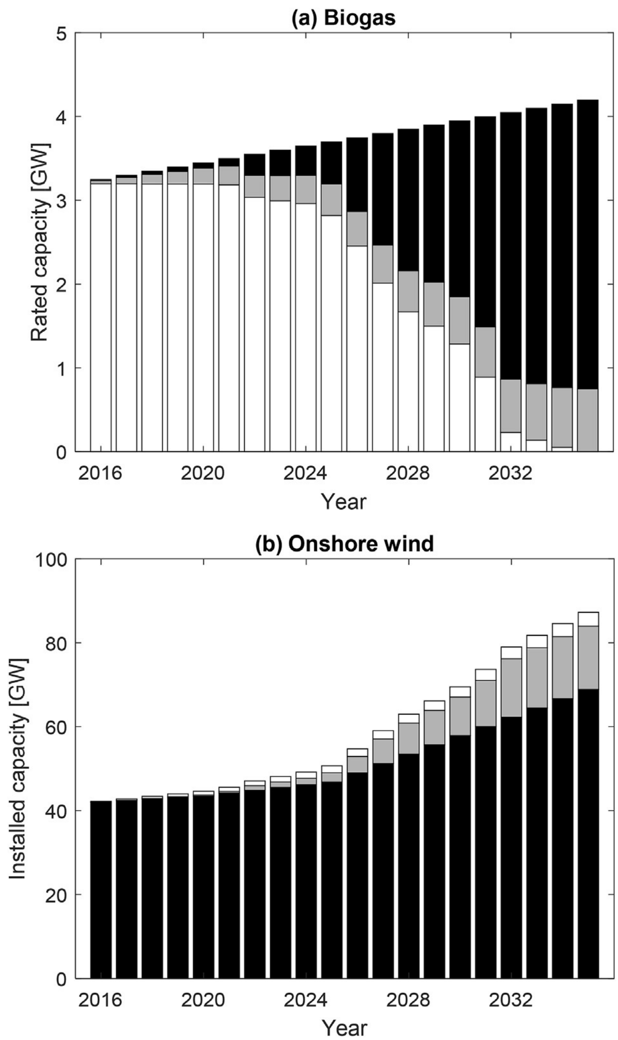

Fig. 1. Rated capacity of biogas plants (a) and installed capacity of onshore wind turbines (b) in the biogas extension paths *increase* (black), *back-up* (grey) and *phase-out* (white).

the extension of biogas plants and their annual electricity generation, we used new installations of onshore wind turbines as an "adjustment screw" to fulfill the EEG's renewable energy target values (Fig. 1).[4]

2.1.2. Modes of operation of biogas plants

Based on the financial incentives of the EEG, the majority of biogas plants in Germany operate in baseload operation. An amendment to the EEG in 2012 introduced a flexibility premium to spark a paradigm shift towards flexible power generation in existing biogas plants. In addition, since 2014 new biogas plant installations have to mainly generate electricity in a flexible way with a maximum of 4380 full load hours per year (see Table 2). In general, flexible power generation from biogas plants requires investments in additional CHPU and/or gas storage capacities compared to baseload generation. The period between electricity generation of biogas plants is dependent on the gas storage capacity and can be increased through flexible biogas production using various feedstock management strategies [26,27]. As a result,

Table 1
Scenarios based on extension paths and plant configurations of biogas plants [28].

Biogas extension path	Plant configuration	Scenario
Increase (INC)	Base (B)	INC-B
	Flex (F)	INC-F
	Flex+ (F+)	INC-F+
Back-up (BU)	Base (B)	BU-B
	Flex (F)	BU-F
	Flex+ (F+)	BU-F+
Phase-out	Base (B)	REF

we looked at three modes of operation[5]:

- Base: baseload generation of biogas plants.
- Flex: flexible power generation in biogas plants through increased CHPU and gas storage capacities.
- Flex+: flexible power generation in biogas plants through increased CHPU and gas storage capacities as well as flexible biogas production to increase flexibility.

The scenarios in this paper are designed to compare the costs and benefits and are based on combining extension paths and plant configurations of biogas plants (Table 1).

2.2. Cost-benefit analysis

To economically assess the scenarios defined in Section 2.1, we used a cost-benefit analysis typically utilized in public investment analysis [29]. In this paper, we compare scenarios with a higher proportion of (flexible) biogas plants to the reference scenario: the phase-out of biogas plants (scenario *REF*). Based on this definition, the costs and benefits[6] over the reference scenario are defined as follows:

Costs (Section 2.3):

- Additional investments in the flexibilization of existing biogas plants and increased operation and maintenance (O&M) costs (Section 2.3.1).
- Capital and operational costs of new installations of flexible biogas plants (Section 2.3.2).

Benefits (Section 2.4):

- Reduced investments in onshore wind turbines; a higher proportion of biogas plants leads to a lower demand for onshore wind turbines to fulfill EEG targets (Section 2.4.1).
- An increased proportion of (flexible) biogas plants reduces the demand for additional flexibility options (e.g. storage technologies and gas turbines) as well as the utilization of conventional power plants with comparably high marginal costs and GHG emissions (e.g. coal-fired power plants) (Section 2.4.2).

The benefit-cost ratio was included as an evaluation criterium and is calculated using the following equation [29]:

$$\text{Benefit-cost ratio} = \text{present value of benefits} \,/\, \text{present value of costs} \quad (1)$$

If the benefit-cost ratio is greater than 1, the investment is

[4] Further details on the biogas extension paths are presented in Refs. [4,20].

[5] Further details on the modes of biogas plant operation are presented in Ref. [23].

[6] Further benefits from flexible power generation of biogas plants are described in detail in Section 4.5.

Table 2
Design of existing biogas plants based on baseload and flexible power generation.

	Baseload power generation	Flexible power generation
Rated capacity	137.0–1872.2 kW	
Full load hours	8000	4380
Installed capacity	150–2050 kW	274.0–3744.3 kW
Power quotient (PQ)	1.1	2
No. of CHPU	1	
Biogas storage capacity[a]	6 h	10 h

[a] The biogas storage capacity is defined as a ratio of storage capacity [m^3] and hourly biogas production [$m^3\ h^{-1}$].

efficient from an economic point of view (benefits exceed the costs); otherwise, if the ratio is below 1 (benefits are lower than the costs), the investment is not beneficial [29]. The present value of benefits and costs was calculated for the period 2016–2035 using a (social) discount rate of 3% [30].

The costs and benefits in biogas plants and onshore wind turbines are indicated by effected and substituted investments respectively. The cash flow of the investment was correspondingly calculated and converted into the net present value based on the year the plant was commissioned. Because the period from 2016 to 2035 was considered, the capital costs include the residual value at the end of the year 2035.

Next, with the exception of the additional saved opportunity costs, the net present value of the investments in biogas and onshore wind turbines were converted to the annuity A by the following equations [29]:

$$A_C = PWC \times \left(\frac{i \times (i+1)^n}{(i+1)^n - 1}\right) \tag{2}$$

$$A_B = PWB \times \left(\frac{i \times (i+1)^n}{(i+1)^n - 1}\right) \tag{3}$$

where A_C is the annuity of the costs, PWC is the present value of cost, i is the discount rate, n is the operational life, A_B is the annuity of the benefits and PWB is the present value of benefits.

2.3. Costs

2.3.1. Flexibilization of existing biogas plants

To calculate the additional capital and O&M costs for the flexibilization of existing biogas plants, we defined their design based on baseload and flexible power generation (Table 2). In contrast to plants providing baseload generation, flexible biogas plants are characterized in this paper by a higher installed capacity of the CHPU and the gas storage capacity. Shifting power generation to a time where there is lower electricity demand requires a reduction in full load hours. Based on the (minimum) requirements of the current EEG, a power quotient (PQ) of 2, which is defined by the ratio of installed and rated capacity (annual average electricity generation[7]) [13], was taken into account. Consequently, the installed capacity of existing flexible biogas plants is two times higher than the rated capacity. The quotient of installed and rated capacity is a suitable indicator to describe the flexibility potential of biogas plants.[8] Consistent with [23], existing biogas plants begin flexible power generation when they reach their final 10 year period of EEG remuneration; older biogas plants are in baseload operation. Furthermore, flexible power generation is mandatory for biogas plants with an installed capacity of more than 100 kW (EEG 2017, § 44b). As a result, more than 85% of Germany's existing biogas plants will generate flexible power by 2025.

The additional costs for flexible power generation from existing biogas plants were calculated based on the methodology of [13]. Furthermore, we took no additional costs for the flexible biogas production into account. Depending on the date of flexibilization, additional investments in CHPU and gas storage capacities as well as further O&M costs were examined (Appendix, Table A1). This was done by determining additional costs for biogas plants with an installed capacity between 150 and 2050 kW using increments of 50 kW for the 2016–2025 period. To calculate the weighted average of additional costs of flexibilization per megawatt, the resulting costs were multiplied by the relative distribution of size classes of Germany's existing biogas plants, also using increments of 50 kW (based on the analysis of [32]). After 2025, existing biogas plants, which operate more than 10 years after flexibilization, will be closed down. Based on the net present value, the annuity was calculated by taking into account an (additional) 10-year operational life of existing biogas plants.

2.3.2. New installations of (flexible) biogas plants

To examine the costs of new biogas installations we defined one future plant design for baseload and flexible power generation (Table 3). According to existing biogas plants, the installed capacity of new installations has to be two times higher than the rated capacity (PQ = 2) (EEG 2017 § 39 h). In this paper, we focused on the cost-efficient biogas plant operation and considered a high installed capacity and the use of energy crops instead of a higher proportion of manure. The economic data of new biogas plants in baseload and flexible power generation were taken from Ref. [33]. These data were used to calculate the annuities based on the capital and O&M costs of new biogas installations for each year during the 2016–2035 period. The calculated annuities for each year were multiplied by the rated capacities of new, required biogas installations in the extension paths biogas *back-up* and *increase* (Appendix, Table A2).

2.4. Benefits

2.4.1. Reduction in onshore wind power plants

The annuity of new onshore wind turbines was based on the LCOE calculated by Ref. [34] (Appendix B). We used these LCOE for the period of 2016–2035 (missing values were linearly interpolated), the real discount rate, the operational life and the full load hours of onshore wind turbines, shown in Table 4, to calculate the missing capital and O&M costs of onshore wind turbines. The capital costs include the residual value at the end of 2035. Annuities of new installations for each year in the period under consideration (and LCOE derived from this) were calculated to be identical to the LCOE of the above-mentioned study. Following the methodology in our previous study [23], the annuities were then calculated with a

[7] Rated capacity [MW] is the quotient of the annual electricty generation [MWh per year] and 8670 h (8694 h in leap years).

[8] Further performance indicators of demand-driven power generation are presented in Ref. [31].

Table 3
Design and characteristics of new biogas installations.

	Baseload power generation	Flexible power generation
Rated capacity	0.913 MW	1 MW
Full load hours	8000	4380
Installed capacity	1 MW	2 MW
Power quotient (PQ)	1.1	2
No. of CHPU	1 x 1 MW	2 x 1 MW
Gas storage capacity	6 h	10 h
Feedstock (mass)	60% maize silage 30% grain silage 10% manure	
LCOE (including credit for heat)	183.4 € MWh^{-1} (2018) 198.5 € MWh^{-1} (2025) 211.5 € MWh^{-1} (2030) 226.0 € MWh^{-1} (2035)	191.6 € MWh^{-1} (2018) 207.2 € MWh^{-1} (2025) 221.0 € MWh^{-1} (2030) 236.7 € MWh^{-1} (2035)

Table 4
Assumptions about the economic assessment of onshore wind turbines.

Parameter	Assumption	Source/Note
Operational life	20 years	[34]
Annual full load hours	2000	[24]
Discount rate (nominal)	4.6%	[36]
Discount rate (real)	3.5%	Own calculations according to Ref. [37]
Operation and maintenance (O&M)	2.5% of initial investment per year	[38]
Capital-related rate of price increase	0.59%	Average annual increase in capital goods in Germany from 2000 to 2015 [39]
Operation-related rate of price increase	1.45%	Average annual increase of operating and maintenance costs in Germany from 2000 to 2015 [40]
LCOE	59.4 € MWh^{-1} (2015) 52.5 € MWh^{-1} (2020) 43.8 € MWh^{-1} (2030) 40.0 € MWh^{-1} (2040)	[34]

Table 5
Total discounted system costs (without onshore wind and biogas) in all scenarios considered for the 2016–2035 period [23].

Biogas extension path	Scenario	System costs [10^9 €]
Increase (INC)	INC-B	126.273
	INC-F	124.654
	INC-F+	124.524
Back-up (BU)	BU-B	127.099
	BU-F	125.929
	BU-F+	125.677
Phase-out	REF	127.353

nominal discount rate that included the capital- and operation-related price increase of capital and O&M costs respectively (Table 4). Based on the LCOE data of [34], the LCOE of new onshore wind farms in 2018 totals 55.2 € MWh^{-1} which is similar to the first auction of the German tendering system in 2018 (average of 57.3 € MWh^{-1}) [35].

Finally, the annuities, which were calculated for each year within the 2016–2035 period, were multiplied by the saved capacities of onshore wind turbines in the biogas extension paths *back-up* and *increase* and compared to the extension path *phase-out* (Appendix A, Table A3).

2.4.2. Additional saved opportunity costs

The reduced utilization of conventional power plants and decreased investments in further flexibility options, such as storage technologies, can be interpreted as additional saved opportunity costs of a higher proportion of (flexible) biogas plants compared to their phase-out. Thus, we took the system costs from a previous study [23] that analyzed the impact of flexible power generation in biogas plants on the electricity system. In this study, the system

Table 6
Installed capacities of conventional power plants and renewable energies when lignite- and coal-fired power plants are phased out [GW].

	2016	2020	2025	2030	2035	Source
Conventional						
Nuclear	10.8	8.1	–	–	–	[41,42]
Lignite	20.9	6.0	3.0	3.0	–	
Coal	28.7	8.0	8.0	7.0	4.0	
Gas	28.5	26.0	26.0	23.0	19.0	
Renewables						
Onshore wind						Own calculations based on [41,43,44]
Biogas phase-out	42.2	55.2	67.5	91.2	106.4	
Biogas back-up		54.4	65.9	88.7	103.1	
Biogas increase		54.1	63.7	79.5	88.1	
Offshore wind	3.9	7.0	14.5	23.0	26.8	
Photovoltaic	41.2	50.3	67.1	77.3	91.1	

Table 7
Capital and marginal costs of new installations of gas-fired and combined cycle power plants in the non-linear optimization model under consideration.

	2020	2025	2030	2035	Source
Capital costs (annuity) [10^3 € MW^{-1}]	82.6	87.9	93.7	100.0	Own calculations based on [45]
Marginal costs [€ MWh^{-1}]	59.0	73.1	76.7	80.3	Own calculations based on [24,45–47]

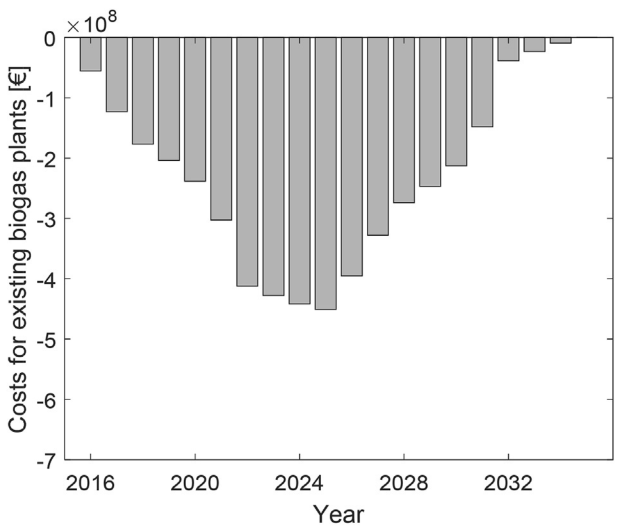

Fig. 2. Additional costs for the flexibilization of existing biogas plants in all scenarios with flexible power generation. Costs are not discounted.

costs included the marginal costs of conventional power plants and the investments in pumped-storage plants, Li-ion batteries and/or gas turbines as well as their marginal costs (Table 5). However, the capital and marginal costs of the flexibilization of existing biogas plants and/or the installation of new biogas and onshore wind turbines were not considered.

2.5. Early phase-out of lignite- and coal-fired power plants

According to the findings of [23], Germany's electricity system has a sufficient amount of flexible conventional power plants. Additional investments in pumped-storage plants, gas turbines and Li-ion batteries will start from the years 2030 and 2035 respectively [23]. However, an early phase-out of lignite- and coal-fired power plants is crucial in order to keep global temperatures to one and a half degree Celsius over preindustrial levels, [41]. To analyze if there is a difference when the energy transition towards renewable energies is accelerated, we compared the results of the cost-benefit analysis with an early reduction in conventional power plants. This was achieved by utilizing the methodologies described in previous studies [4,23], reducing the installed capacities of conventional power plants, and increasing the installed capacity of renewable energies based on [41] (Table 6).

Contrary to the methodology of [23], we considered the endogenous installation of gas-fired and combined cycle power plants instead of gas turbines in the non-linear optimization model. The early phase-out of lignite- and coal-fired power plants is expected to require conventional power plants that have a higher utilization rate than gas turbines. Assumptions regarding the capital and marginal costs are presented in Table 7.

We also analyzed how a higher installed capacity and a lower number of full load hours of biogas plants affects system costs. In addition to a PQ of 2, we considered a PQ of 3 which is characterized by 2920 full load hours per year. The additional costs of a higher

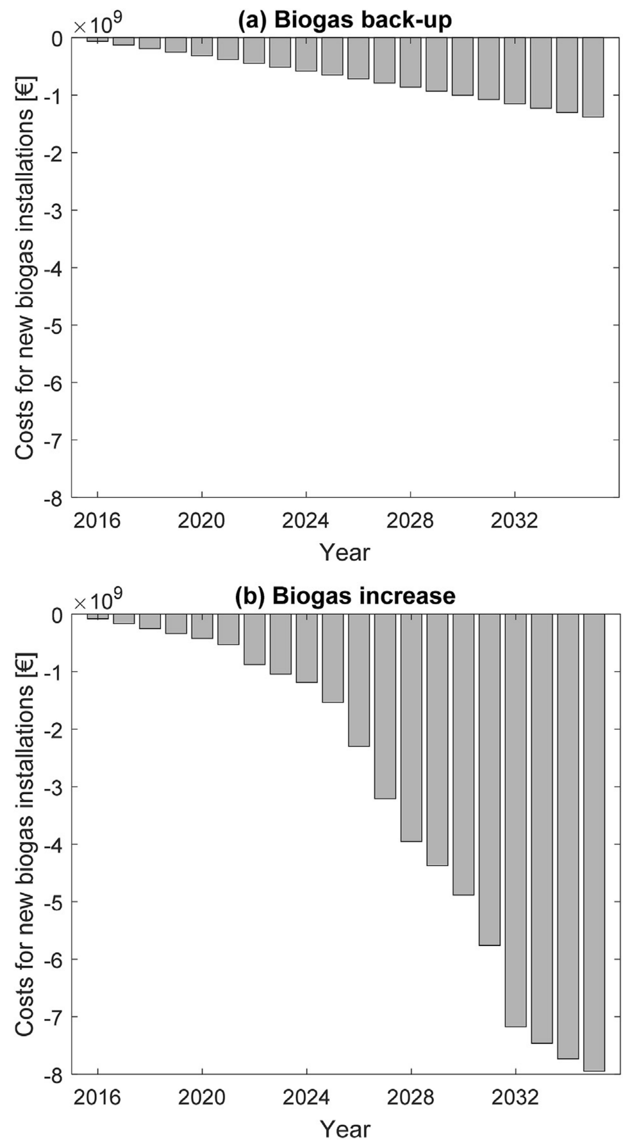

Fig. 3. Costs for new biogas plants in the extension path *back-up* (a) and *increase* (b). Costs are not discounted.

CHPU capacity were taken from the cost formula of [48]. The installed capacity of each CHPU was increased to 1.5 MW in new biogas installations.

2.6. Maximum LCOE of new biogas installations

In order to calculate the maximum LCOE of new biogas installations that would allow economically feasible operation as part of flexibility options for Germany's future electricity system (for the period of 2016–2035), costs were varied in the cost-benefit analysis until a net present value of 0 was achieved. This was carried out for an early and non-early phase-out of lignite- and coal-fired power plants.

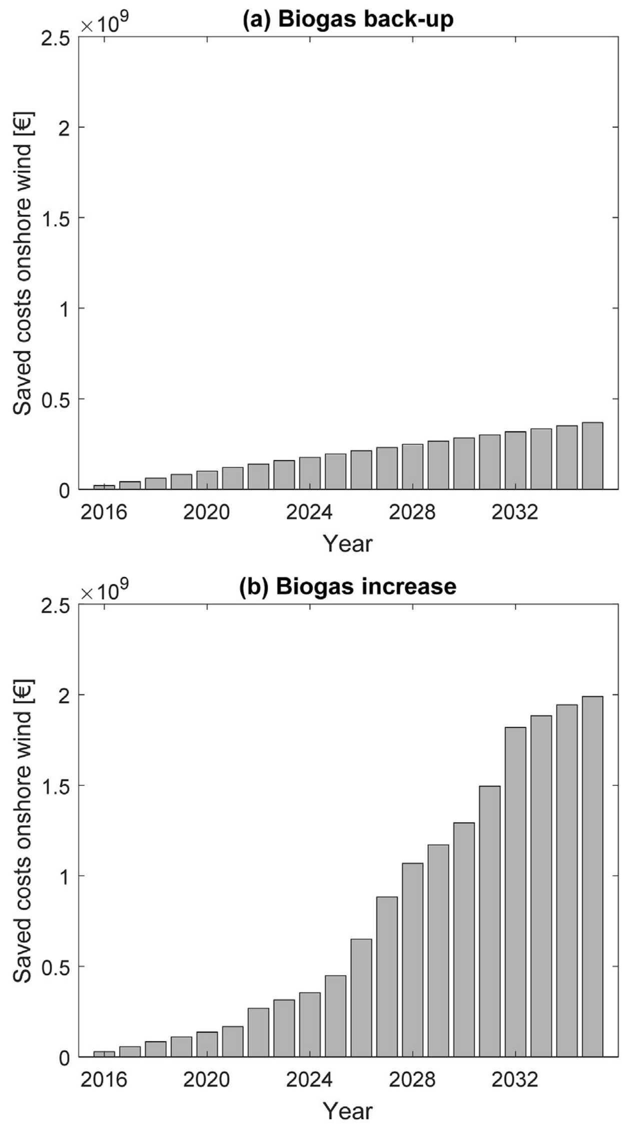

Fig. 4. Saved costs for onshore wind turbines by increasing the proportion of (flexible) biogas plants in the extension paths *back-up* (a) and *increase* (b). Benefits are not discounted.

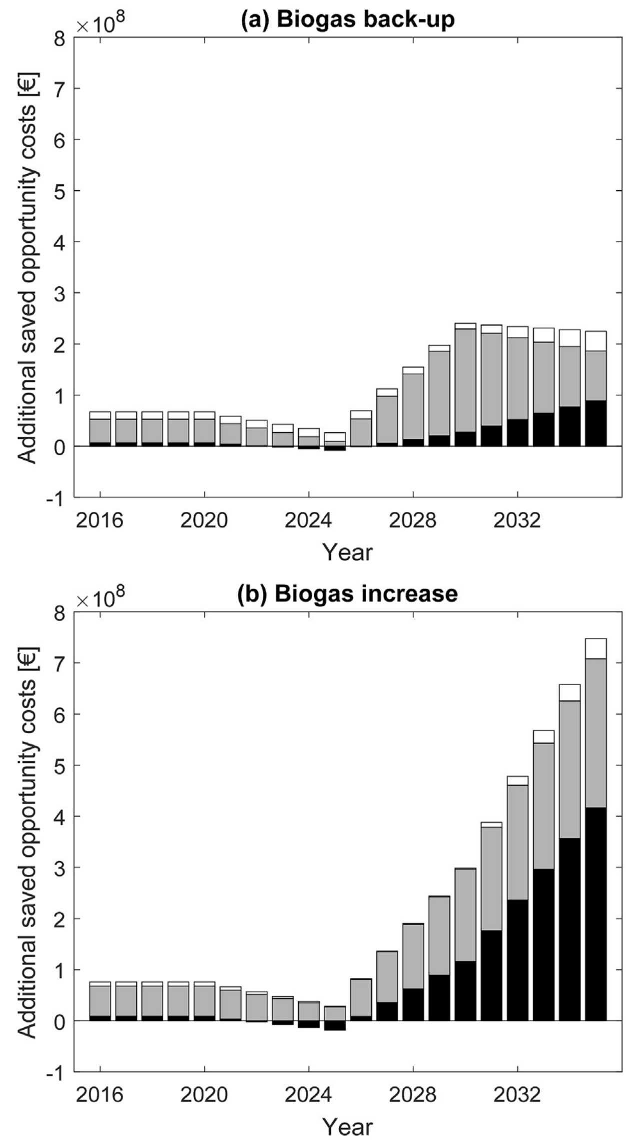

Fig. 5. Additional saved opportunity costs through a higher proportion of (flexible) biogas plants in the extension paths *back-up* (a) and *increase* (b). Plant configuration *Base* (black), *Flex* (grey), *Flex+* (white). Benefits are not discounted.

3. Results

3.1. Costs

3.1.1. Flexibilization of existing biogas plants

Depending on the commissioning year of existing biogas plants in Germany, the highest costs for the flexibilization of existing biogas plants occur in the mid-2020s (Fig. 2). This is why existing biogas plants start to phase out after an operational life of 20 years. The majority of Germany's biogas plants was commissioned between the years 2004 and 2012 [11]. In 2025, when the electricity generated by existing flexible biogas plants will peak, annual costs will be their highest at €0.45 billion. To summarize, the total costs for the flexibilization of existing biogas plants for the period of 2016–2035 amounts to €4.5 billion.

3.1.2. New installations of flexible biogas plants

In the biogas extension path *back-up*, the costs for new flexible biogas plants increase linearly through the constant annual installation of 75 MW (installed capacity) per year (Fig. 3). The highest costs for new biogas installations occur in the year 2035 (€1.4 billion) and the total costs for the period under consideration amount to €13.9 billion. In contrast, total costs for the installation and operation of new biogas plants increase to €61.2 billion in the biogas extension path *increase.* The phase-out of existing biogas plants causes a sharp increase in total costs in the years 2027 and 2032. The total annual costs in the biogas extension path *increase* vary between €0.08 and 7.9 billion.

3.2. Benefits

3.2.1. Reduction in onshore wind turbines

An increase in the proportion of biogas plants in the future German electricity system leads to a reduction in onshore wind turbines to fulfill the target values of the EEG. Therefore, the benefits of a reduction in onshore wind turbines in the biogas extension paths *back-up* and *increase* show a similar trend (Fig. 4). However, the replacement of onshore wind turbines is linked to

Table 8
Benefit-cost ratios and net present values in the scenarios under consideration (compared to the reference scenario). Non-early phase-out of lignite- and coal-fired power plants.

Biogas extension path	Scenario	Benefit-cost ratio	Net present value [B €]
Increase (INC)	INC-B	0.307	−25.82
	INC-F	0.308	−29.32
	INC-F+	0.311	−29.19
Back-up (BU)	BU-B	0.332	−5.98
	BU-F	0.324	−8.66
	BU-F+	0.343	−8.41

lower benefits due to their lower capital and O&M costs. In the extension path *back-up*, the total benefits of reduced onshore wind turbines for the period of 2016–2035 amount to €4.0 billion. Furthermore, the total benefits increase to €16.2 billion in the biogas extension path *increase.*

3.2.2. Additional saved opportunity costs

Increasing the proportion of (flexible) biogas plants in the future German electricity system reduces the utilization of conventional power plants, which are characterized by high marginal costs (and GHG emissions), and investments in further flexibility options. Having fewer additional biogas plants (*back-up* extension path)

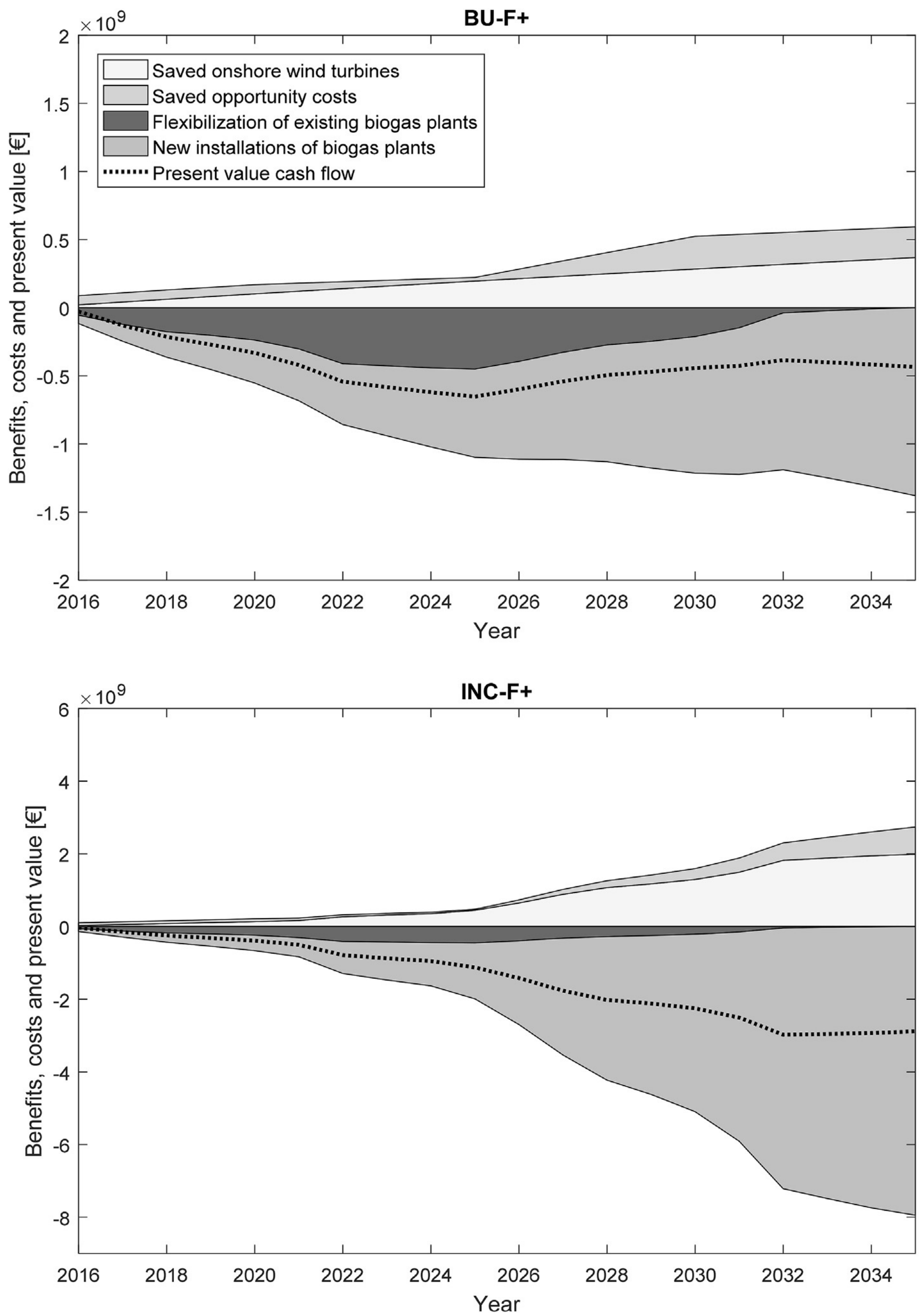

Fig. 6. Costs (negative values) as well as benefits (positive values) and present value of the annual cash flow in the scenarios *BU-F+* and *INC-F+*. Costs and benefits are not discounted.

Table 9
Benefit-cost ratios and net present values in the considered scenarios (in comparison to the reference scenario). Early phase-out of lignite- and coal-fired power plants.

PQ 2			
Biogas extension path	Scenario	Benefit-cost ratio	Net present value [B €]
Increase (INC)	INC-B	0.383	−22.98
	INC-F	0.527	−20.04
	INC-F+	0.528	−19.99
Back-up (BU)	BU-B	0.634	−3.28
	BU-F	0.718	−3.62
	BU-F+	0.759	−3.09
PQ 3			
Biogas extension path	**Scenario**	**Benefit-cost ratio**	**Net present value [B €]**
Increase (INC)	INC-F	0.545	−20.89
	INC-F+	0.566	−19.96
Back-up (BU)	BU-F	0.767	−3.71
	BU-F+	0.769	−3.68

results in total benefits of up to €2.5 billion (scenario BU-F+) for the period under consideration (Fig. 5). However, in the biogas extension path *increase*, the benefits are higher and are characterized by total benefits of up to €4.4 billion (scenario INC-F+). In both biogas extension paths, the highest savings are achieved in the Flex + mode of operation, when the biogas plants are most flexible. In contrast, baseload generation in biogas plants leads to the lowest overall benefits. Furthermore, the highest annual benefits are achieved in the INC-F+ scenario and the year 2035 (€0.75 billion). Due to the high installed capacity of conventional power plants, the benefits of a higher proportion of biogas plants start to become significant from the mid-2020s onwards.

3.3. Cost-benefit analysis

Table 8 shows the benefit-cost ratio for each scenario under consideration compared to the reference scenario. An increasing proportion of (flexible) biogas plants leads to an overall benefit-cost ratio of less than one in all scenarios. The costs of additional biogas plants exceed the benefits of their dispatchable electricity generation (Fig. 6). As a result, the investments in flexible power generation from biogas plants (and additional capacities) are thwarted by a sufficient installed capacity of conventional power plants and existing dispatchable pumped-storage plants. Focusing on the net present value, the best result was achieved in the scenario BU-B (-€6.0 billion); the lowest in the scenario INC-F (-€29.3 billion). This is explained by the fact that there is a sufficient amount of existing flexibility options in the electricity system and additional investments in flexible power generation from biogas plants lead to an oversupply of flexibility. Investments in flexible power generation from biogas plants have to be better coordinated with the installed capacity of further flexibility options, otherwise the efficiency of the energy transition process might be hampered by additional costs. Nevertheless, flexible power generation increases the benefit-cost ratio compared to baseload power generation. In both biogas extension paths, the highest benefit-cost ratio was calculated in the *Flex +* plant configuration.

4. Discussion

4.1. Study design

In this study, we focus on the energy transition pathways of Germany's biogas plants. An alternative approach might be the so-called “greenfield approach” optimizing power plants without taking into consideration the existing legal framework and power plants (e.g. the study by Ref. [22]). On the one hand, the advantage of our approach is that the dynamic development of decommissioning existing conventional power plants and increasing renewable energies can be analyzed in more detail. This also allows us to identify an advantageous time for investing in flexibility options such as storage technologies or biogas plants. From the perspective of policymakers, decisions on the future design of renewable energy systems and cost-efficient policy choices have to take into account currently installed capacities of power plants and legal frameworks. On the other hand, the greenfield approach ensures more degrees of freedom to optimize the future energy system. This might be a template for changing current frameworks. In summary, we calculate benchmarks for an economically feasible operation of (flexible) biogas plants in future electricity systems taking into account existing frameworks. Cost-efficient energy/electricity systems are defined in other studies.

In contrast to the results of this analysis, the study by Ref. [22] used a greenfield approach. It calculated lower annual generation costs in Germany's electricity system when its predominantly decarbonized renewable energies and bioenergy plants are included in this system. However, the author of [22] optimized Germany's power plant portfolio with regard to varying proportions of renewable energies without taking existing conventional power plants into consideration. Consequently, the optimization of the power plant portfolio in the target system was based on annualized costs of power plants and the potentials of their energy carriers, among other things. By concentrating on the target system and not taking into account existing power plants, biomass plants represent a way to reduce annual generation costs in renewable energy systems. However, our study took into account Germany's current power plant portfolio and the net present value of the total system costs for the period under consideration. This is why we did not calculate the cost-efficient impact of additional biogas plants on total system costs.

Cost-benefit analyses are subject to the risk of uncertainties surrounding the future cash flow generated by investment [30]. Consequently, a sensitivity analysis was carried out on the robustness of the results when changes are made to different parameters (Section 4.4).[9]

4.2. Early phase-out of lignite- and coal-fired power plants

The early phase-out of lignite- and coal-fired power plants leads to a higher benefit from flexible biogas plants. Instead of existing

[9] Further details on the limitations of the non-linear optimization model considered in this analysis, are shown in Ref. [23].

Table 10
Maximum LCOE [€ MWh^{-1}] of new biogas installations in the cost-benefit analysis that allows operations to be economically feasible. Commissioning year is 2018.

Scenario	*Phase-out of lignite- and coal-fired power plants*		
	Non-early	*Early, PQ 2*	*Early, PQ 3*
BU-B	60.9	116.2	
BU-F	14.1	117.5	116.8
BU-F+	19.3	128.3	117.6
INC-B	56.3	70.3	
INC-F	47.2	92.9	90.4
INC-F+	47.9	93.2	94.9

conventional power plants, biogas power generation substitutes new installations of storage technologies and gas-fired power plants (Appendix, Table A4). Therefore, the benefit-cost ratio and the net present value increases (Table 9). The higher flexibility resulting from an increased installed capacity of biogas plants (PQ 3) enhanced the benefit-cost ratio and lowered the net present value except for in the INC-F+ scenario. Nevertheless, the additional benefits through the early phase-out of conventional power plants does not result in an economically feasible operation of (flexible) biogas plants (benefit-cost ratio ≤ 1). If biogas plants are to remain a component of the future electricity system, their power generation has to be as flexible as possible. The highest net present values were achieved in *Flex* + mode of operation when lignite- and coal-fired power plants are phased out early.

The figure indicating annual costs, annual benefits and the present value of the early phase-out of lignite- and coal-fired power plants is shown in the Appendix (Figure A1).

4.3. Maximum LCOE of new biogas installations

A non-early phase-out of lignite- and coal-fired power plants limits the maximum LCOE of new biogas installations to 60.9 € MWh^{-1} for a net present value ≥ 0 in scenario BU-B, when these plants begin operation in 2018 (Table 10). In a non-early phase-out, the maximum LCOE of new biogas plants was calculated in base-load generation without investment in the flexibilization of existing plants (scenario BU-B). In contrast, an early phase-out of lignite- and coal-fired power plants allows higher LCOE for (flexible) power generation from biogas plants. In this case, their maximum costs

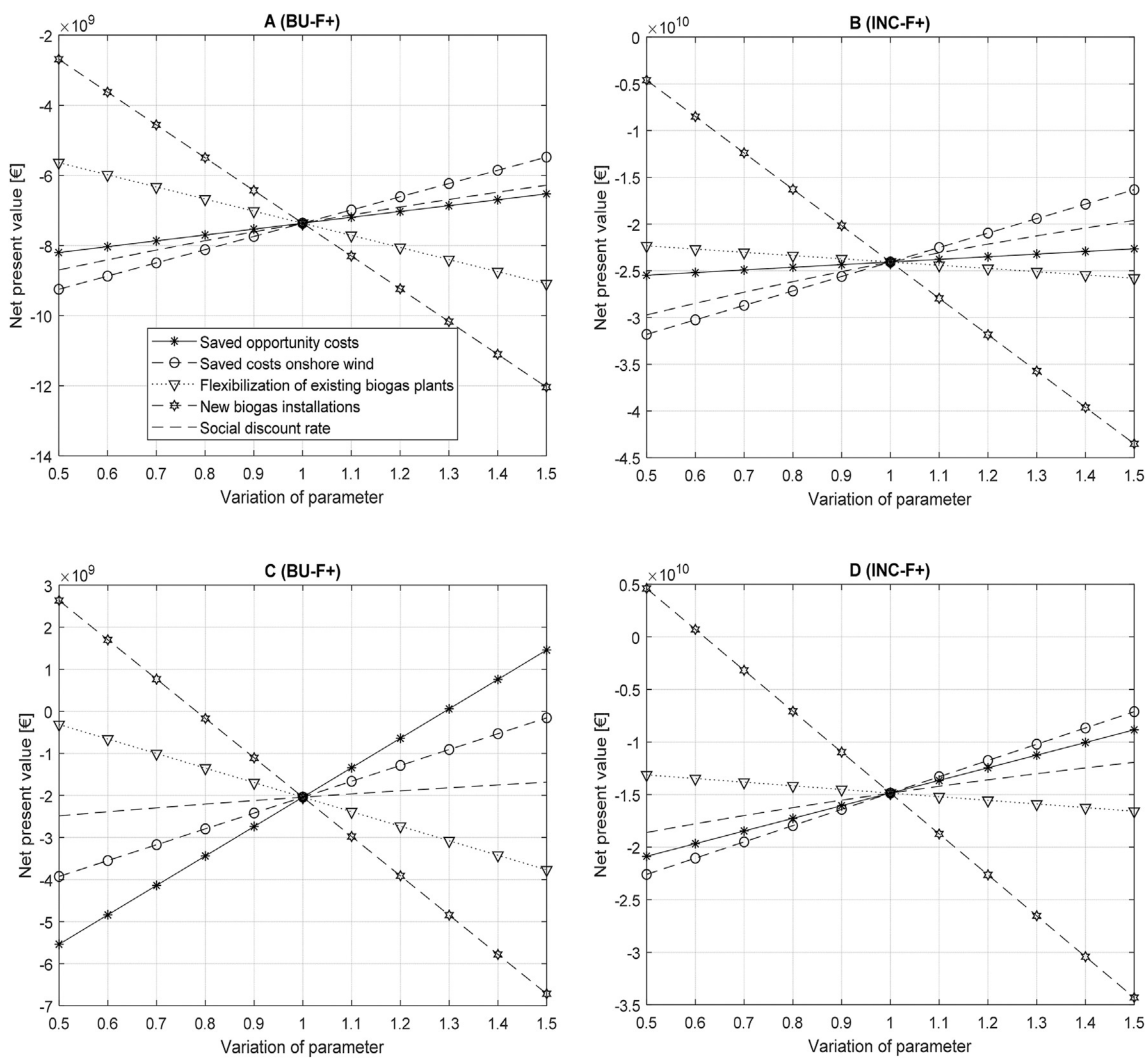

Fig. 7. Net present value in the scenarios BU-F+ and INC-F+ taking into account a non-early (A|B) and an early phase-out of coal- and lignite-fired power plants (PQ 2) (C|D).

Table 11
A selection of further benefits of biogas plants that are not taken into account in the cost-benefit analysis.

Energy system	Environmental/climate benefits	Economic benefits	Other benefits
• Lower demand for power grid extension [49] • Source of carbon for the methanation of hydrogen [50] • Cost savings from conventional power plants (e.g. lower amount of start/stop operations) [51] • (Decentralized) heat supply and substitution of fossil fuels [52]	• Reduction in agricultural GHG emissions through the use of manure and other organic waste products [53,54] • Substitution of inorganic fertilizer through the use of biogas digestate [55] • Reduction in GHG emissions and air pollution in the heating sector [56]	• Additional income for farmers [57] • Additional jobs in rural areas [58] • Positive effect on the added value in rural areas [58]	• Source of carbon dioxide for BECCS (bio-energy with carbon capture and storage) [59] • Reduction in odor and fewer pathogens when manure is used [60]

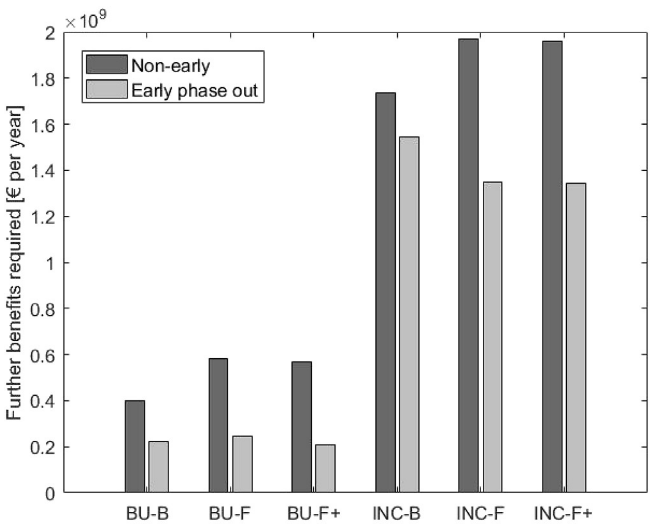

Fig. 8. Further benefits required from biogas plants to ensure an economically feasible operation (compared to their phase-out) with respect to a non-early and an early phase-out of coal- and lignite-fired power plants. Benefits are annualized by Formula (3), a (social) discount rate of 3% and a period of 20 years.

vary between 90.4 and 128.3 € MWh^{-1} in 2018 depending on their future plant design.

4.4. Sensitivity analysis

In terms of the net present value of the cost-benefit analysis, the highest impact was achieved in the BU-F+ and INC-F+ scenarios by varying new biogas installation costs (Fig. 7). In the BU-F+ scenario and in the non-early phase-out of lignite- and coal-fired power plants, the flexibilization of existing biogas plants is highly sensitive. The saved opportunity costs become more important when lignite- and coal-fired power plants are phased-out earlier (Fig. 7 C D). Otherwise, this benefit does not highly impact the net present value (Fig. 7 A B).

4.5. Further benefits of biogas plants

In this analysis, we focused on the benefits of (flexible) power generated by biogas plants in the electricity system. In addition to the aforementioned benefits, biogas plants create further benefits in the energy system and other areas (Table 11). Those effects were not monetarized in this analysis, but they have to be considered when biogas plants are ultimately assessed in economic terms. Therefore, the other annualized benefits that are needed for an economically feasible operation in the electricity system are calculated in Fig. 8. Lowest other benefits are achieved in the BU-F+ scenario when lignite- and coal-fired power plants are phased out earlier (approx. €0.2 billion per year). Whereas, a non-early phase-out of those plants in the INC-F scenario requires other annualized benefits of about €2.0 billion for a non-negative net present value.

If Germany's future electricity system is highly decentralized, the highest benefit from flexible power generation might be achieved by a lower demand for power grid extension. More decentralization leads to an increase in regional responsibility to ensure sufficient power supply.

5. Conclusions and policy implications

In this analysis, we assessed economically varying biogas extension paths and modes of operation in the future German electricity system for the period of 2016–2035. This was done by examining a cost-benefit analysis in order to evaluate the impact of (flexible) power generation from biogas plants on the substitution of further flexibility options and onshore wind turbines. The key findings are as follows:

- The maximum LCOE of new biogas installations in 2018 that enables economically feasible operation in the electricity system is about €128 MWh^{-1}. Otherwise, further benefits have to compensate for the economic results of the biogas impact on the electricity system.
- Without cost reductions, additional investments in biogas plants have to be accompanied by further benefits in other sectors and areas to ensure economically feasible operation, e.g. the substitution of fossil fuels in the heating sector and a reduction in GHG emissions in the agriculture sector.
- An early phase-out of lignite- and coal-fired power plants increases the economic feasibility of biogas plants. In such case, the power generated from biogas plants should be as flexible as possible through a combination of flexible biogas production and electricity generation. Nevertheless, only accelerating the decommissioning of conventional power plants does not enable an economically feasible operation of flexible power generation from biogas plants.
- Based on the plant design and feedstock under consideration, the best results were achieved in the biogas extension path *back-up*, characterized by a low construction rate for new biogas plants.

From the broader perspective of policymakers, we recommend the following strategies:

- The extension path, the mode of operation and the future design of biogas plants should be better coordinated with the demand

for flexibility in the future German electricity system. For example, decommissioning conventional power plants might be linked to the extension of renewable energies in the electricity system.
- Current overcapacities of conventional power plants should be lowered to avoid additional costs when transforming the energy system.
- Further benefits of biogas plants have to be monetarized to derive optimized extension paths and modes of operation for biogas plants.
- Optimization of biogas plants and an increasing use of organic waste products in biogas production might enhance the environmental/climate benefits and result in higher outcomes in the economic assessment of biogas plants.
- The further development of energy system models is needed to analyze energy transition paths in more detail. Advanced energy system models can be used as decision-making tools for policymakers.

For further research, we suggest a more detailed cost-benefit analysis of various biogas extension paths and modes of operation that take into account additional impacts of bioenergy on their economic assessment. Based on this methodology, further benefits from (flexible) power generation in biogas plants has to be monetarized. For example, a regional value creation from bioenergy, characterized by the generation of jobs and tax revenues in rural areas. In addition, sensitivity analysis dealing with varying extension paths of renewable energies (for example a higher proportion of PV plants) has to be carried out on the robustness of the results.

Acknowledgements

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Appendix A

Table A.1
Annuities and rated capacities for the flexibilization of existing biogas plants considered in the cost-benefit analysis for the period of 2016–2035.

Year	Annuity flexibilization of existing biogas plants [10^3 € (MW_{rated}*year)$^{-1}$]	Additional rated capacity of biogas plants in flexible mode of operation [MW_{rated}]
2016	−151.78	366
2017	−153.96	439
2018	−156.17	344
2019	−158.43	170
2020	−160.71	214
2021	−163.04	395
2022	−165.41	662
2023	−167.82	92
2024	−170.26	82
2025	−172.75	53

Table A.2
Annuities and installations (rated capacity) of new biogas plants considered in the cost-benefit analysis for the period of 2016–2035. Including credit for heat.

Year	Annuity new flexible biogas installations [10^3 € (MW_{rated} *year)$^{-1}$]	Annuity new baseload biogas installations [10^3 € (MW_{rated} *year)$^{-1}$]	Annual installations of new biogas plants [MW_{rated}]	
			Biogas extension path *back-up*	Biogas extension path *increase*
2016	−1638	−1567	37.5	50.0
2017	−1658	−1587	37.5	50.0
2018	−1679	−1606	37.5	52.3
2019	−1699	−1626	37.5	50.0
2020	−1719	−1645	37.5	50.0
2021	−1739	−1664	37.5	60.5
2022	−1759	−1683	37.5	197.9
2023	−1778	−1702	37.5	92.9
2024	−1796	−1720	37.5	82.1
2025	−1815	−1739	37.5	191.9
2026	−1833	−1757	37.5	415.7
2027	−1858	−1780	37.5	489.4
2028	−1884	−1804	37.5	394.4
2029	−1910	−1828	37.5	220.0
2030	−1936	−1853	37.5	264.4
2031	−1963	−1878	37.5	445.4
2032	−1990	−1903	37.5	711.8
2033	−2017	−1928	37.5	142.0
2034	−2045	−1954	37.5	132.5
2035	−2073	−1980	37.5	103.3

Table A.3
Annuities and installations of onshore wind turbines considered in the cost-benefit analysis for the period of 2016–2035 (installed capacity).

Year	Annuity onshore wind [10^3 € (MW*year)$^{-1}$]	Annual reduced installations of onshore wind turbines [MW] – compared to the biogas extension path *phase-out*	
		Biogas extension path *back-up*	Biogas extension path *increase*
2016	−128	164	221
2017	−126	164	221
2018	−123	164	221
2019	−121	164	221
2020	−118	164	221
2021	−117	164	265
2022	−116	164	867
2023	−114	164	407
2024	−113	164	359
2025	−112	164	840
2026	−110	164	1821
2027	−109	164	2144
2028	−108	164	1728
2029	−106	164	963
2030	−105	164	1158
2031	−104	164	1951
2032	−104	164	3118
2033	−104	164	622
2034	−103	164	580
2035	−103	164	453

Table A.4
Additional accumulated installed capacities of flexibility options taking into consideration an early phase-out of conventional power plants. Comparison to a non-early one in parenthesis (see Ref. [23]) [GW].

Scenario	Pumped-Storage				Li-ion				Gas-fired power plant			
Year	2020	2025	2030	2035	2020	2025	2030	2035	2020	2025	2030	2035
REF	0 (0)	2.22 (+2.22)	2.48 (+1.74)	4.71 (0)	0 (0)	0.02 (+0.02)	1.14 (+1.14)	3.22 (+2.00)	10.28 (+10.28)	16.71 (+16.71)	16.71 (+15.66)	20.88 (+19.83)
BU-B	0 (0)	0.86 (+0.86)	0.87 (+0.21)	4.29 (−0.42)	0 (0)	0.08 (+0.08)	1.35 (+1.35)	3.18 (+2.14)	10.18 (+10.18)	17.97 (+17.97)	17.97 (+17.13)	20.98 (+20.13)
BU-F	0 (0)	0.01 (+0.01)	0.79 (+0.13)	3.64 (−1.07)	0 (0)	0.02 (+0.02)	2.07 (+2.07)	3.22 (+2.45)	8.26 (+8.26)	15.45 (+15.45)	15.45 (+15.45)	20.94 (+20.63)
BU-F+	0 (0)	0 (0)	0.57 (0)	3.57 (−1.14)	0 (0)	0.01 (+0.01)	2.07 (+2.07)	3.18 (+2.53)	8.26 (+8.26)	15.45 (+15.45)	15.45 (+15.45)	20.94 (+20.51)
INC-B	0 (0)	0.77 (0)	0.77 (0)	3.05 (−1.66)	0 (0)	0.31 (+0.31)	0.80 (+0.80)	3.13 (+3.13)	10.14 (+10.14)	17.54 (+17.54)	17.54 (+17.51)	20.51 (+20.49)
INC-F	0 (0)	0 (0)	0.01 (0)	1.81 (−2.90)	0 (0)	0 (0)	0.23 (+0.23)	3.13 (+3.13)	8.16 (+8.16)	14.63 (+14.63)	14.63 (+14.63)	17.24 (+17.24)
INC-F+	0 (0)	0 (0)	0 (0)	1.00 (−3.71)	0 (0)	0.03 (+0.03)	0.26 (+0.26)	3.13 (+3.13)	8.16 (+8.16)	14.60 (+14.60)	14.60 (+14.60)	18.14 (+18.14)

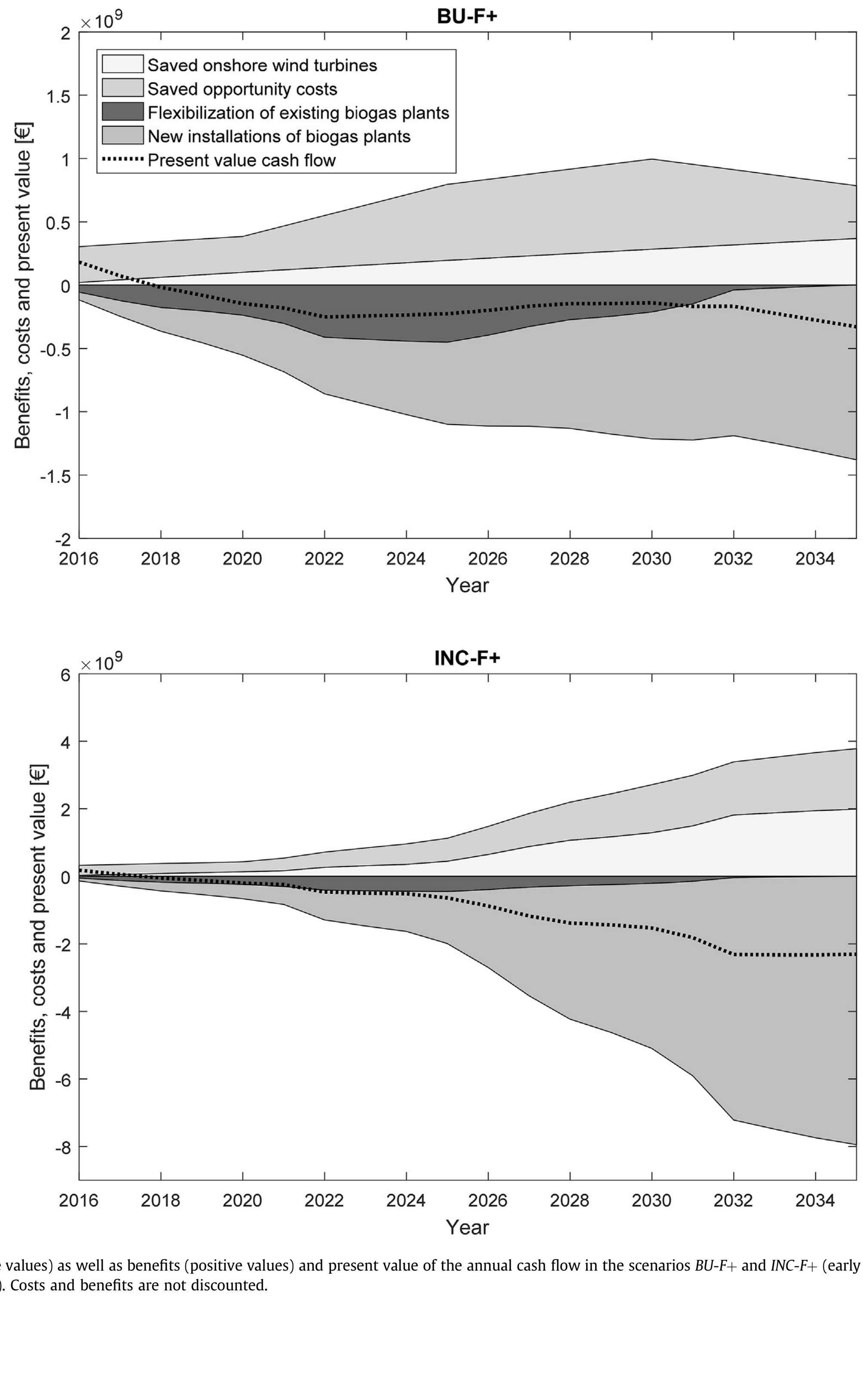

Fig. A.1. Costs (negative values) as well as benefits (positive values) and present value of the annual cash flow in the scenarios *BU-F+* and *INC-F+* (early phase-out of lignite- and coal-fired power plants). Costs and benefits are not discounted.

Appendix B

The LCOE can be calculated by the following equation (adapted from Refs. [36,61]):

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{E_t - R_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{G_t}{(1+i)^t}} \tag{4}$$

I_0 investment expenditures,
E_t total expenditures in the year t
R_t heat revenues in the year t (in the case of biogas plants)
G_t electricity generated in the year t
i discount rate
t year within the operational life

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Contribution to the Articles

Contribution to Article 1

Lauer, M.; Thrän, D. (2017), Biogas plants and surplus generation: Cost driver or reducer in the future German electricity system? Energy Policy, 109, 324–336.
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Markus Lauer had the idea, carried out the literature review, developed the methodology, performed the calculations and wrote the paper. Daniela Thrän contributed to the development of scenarios, provided expert guidance and feedback on the manuscript.

Contribution to Article 2

Lauer, M.; Thrän, D. (2018), Flexible Biogas in Future Energy Systems—Sleeping Beauty for a Cheaper Power Generation. Energies 2018, 11, 761. DOI: 10.3390/en11040761

Markus Lauer developed the optimization model, carried out the case study for Germany, and wrote the manuscript. Daniela Thrän supervised the work, contributed to the development of scenarios as well as to the conclusions, and co-wrote the work.

Contribution to Article 3

Lauer, M.; Leprich U.; Thrän, D. (2020), Economic assessment of flexible power generation from biogas plants in Germany´s future electricity system. Renewable Energy (2020), 146, 1471-1485. DOI: 10.1016/j.renene.2019.06.163

Markus Lauer had the idea, carried out the literature review, developed the methodology, performed the calculations and wrote the paper. Uwe Leprich and Daniela Thrän provided expert guidance and feedback on the manuscript.

Appendix

Table A1: Sets used in the model 1, including type, range and description. Adapted from Lauer et al. (2017b).

Set	Type	Range	Description
p_t	variable	[0; MaxP]	power generation [GW_{el}]
b_t	variable, parameter	[MinB; MaxB]	biogas production [GW]
s_t	variable	[0; SC]	storage filling level [GWh]
RC	parameter	$R^{\geq 0}$	rated capacity [GW_{el}]
MaxP	parameter	$R^{\geq 0}$	maximum power generation [GW_{el}]
MaxB	parameter	$R^{\geq 0}$	maximum biogas production [GW]
MinB	parameter	$R^{\geq 0}$	minimum biogas production [GW]
SC	parameter	$R^{\geq 0}$	storage capacity [GWh]
PBC	parameter	$R^{\geq 0}$	positive biogas change [GWh]
NBC	parameter	$R^{\leq 0}$	negative biogas change [GWh]

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