



WP 3 – Biogas valorization and efficient energy management

D 3.4: Recommendations for improved energy management at waste water treatment plants



Deliverable 3.4	
<i>Recommendations for improved energy management at waste water treatment plants</i>	
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Abstract	This report analyses the optimal energy management and provides recommendations for highest return on investments for new technology or new operations concepts. A model is developed that simulates the energy management on hourly basis for at Braunschweig WWTP for one full year. Different scenarios are modelled simulating new technologies or intelligent operation concepts at the plant. The total energy cost generated in each scenario is compared to estimate the financial benefits of making alterations at the plant. The analysis illustrates a great potential for an optimised energy management and the following points are recommended: ○ Development of energy prognoses for electricity and heat demand (48h in advance) can optimise the use of biogas storage and thereby energy production at the CHPs ○ Heat to power (TEG) increases the overall electricity yield, which is important in a case with high electricity value such as Germany. ○ Flexibility on the consumption side makes it possible to adjust electricity production and consumption even better, which is important when the CHP units are inflexible (operated only at full load or “on-off”). ○ A heat storage reduces waste of heat and natural gas consumption.

Dissemination level of this document

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Glossary

BRP	Balance Responsible Party
CHP	Combined heat and power
EEG	Erneuerbare-Energien-Gesetz (the Renewable Energy Sources Act)
EEX	European Energy Exchange
EUR	Euro
P2G	Power-to-gas
kW	kilo-watt
kW_e	kilo-watt electricity
kW_t	kilo-watt thermal
kWh	kilo-watt hour
l	litre
MILP	Mixed integer linear programming
MWh	Mega-watt hour
Nm³	Normal cubic meter
TEG	Thermo-electric generator
WWTP	Waste water treatment plant



1. Introduction

This report is made as a part of the Powerstep project, which has received funding under the European Union Horizon 2020 program. The overall objective of the Powerstep project is to create a paradigm shift within waste water treatment by converting WWTP's from energy consumers to energy producers while still achieving a high treatment quality.

As a part of the project, full scale investigations are made on six different WWTP around Europe (2 Germany, Denmark, Sweden, Switzerland and Austria). The sludge from the waste water can be used for biogas production in anaerobic digesters and the biogas can be used for among others electricity production. New technologies can extract more carbon from the waste water compared to conventional treatment. This will increase biogas production thereby producing more energy. The focus of this report is to analyse how to optimise utilisation of the energy produced at the waste water plant.

The purpose of this report is to provide recommendations for highest return on investment for new intelligent operation concepts and new technologies influencing the energy management at WWTP's. To identify this, a model is made to simulate the energy management at the WWTP in Braunschweig on hourly basis for one full year. The energy management analysis is part of case study 4 in the Powerstep project.

1.1. Info on WWTP Braunschweig

The WWTP Braunschweig treats municipal and industrial sewage in an activated sludge process with a total load of 325,000 population equivalents (pe). The raw sewage sludge ($> 180.000 \text{ m}^3/\text{a}$) is stabilized in three anaerobic digestors together with co-substrates (e.g. grease), producing more than 3.7 Mio Nm^3 of biogas which is utilized on-site for energy production in four CHP units.

Additional biogas is available from near-by sites of a biowaste plant (composting), a biogas plant, and a landfill site, so that the total amount of valorized biogas is more than 7.5 Mio Nm^3 per year with an average CH_4 content of 50%.

The total energy demand of the WWTP operation amounts to around $12,500 \text{ MWh/a}$ of electricity and $10,000 \text{ MWh/a}$ of heat. Due to the high amount of external gas available at the site, the degree of energy self-sufficiency of this system in the annual balance sheet is higher ($> 100\%$) than at conventional WWTPs of this size.

Nevertheless, daily and seasonal dynamics of energy demand and production require a certain amount of energy (i.e. electricity, but also gas and oil for heating) to be purchased at certain times, while energy is sold in form of electricity and heat at other times. Hence, there could be a potential for optimisation of biogas usage to minimize overall costs of energy management at WWTP Braunschweig.

Goal of this study:

- Recommendations for highest return on investment for new technologies and intelligent operation principles

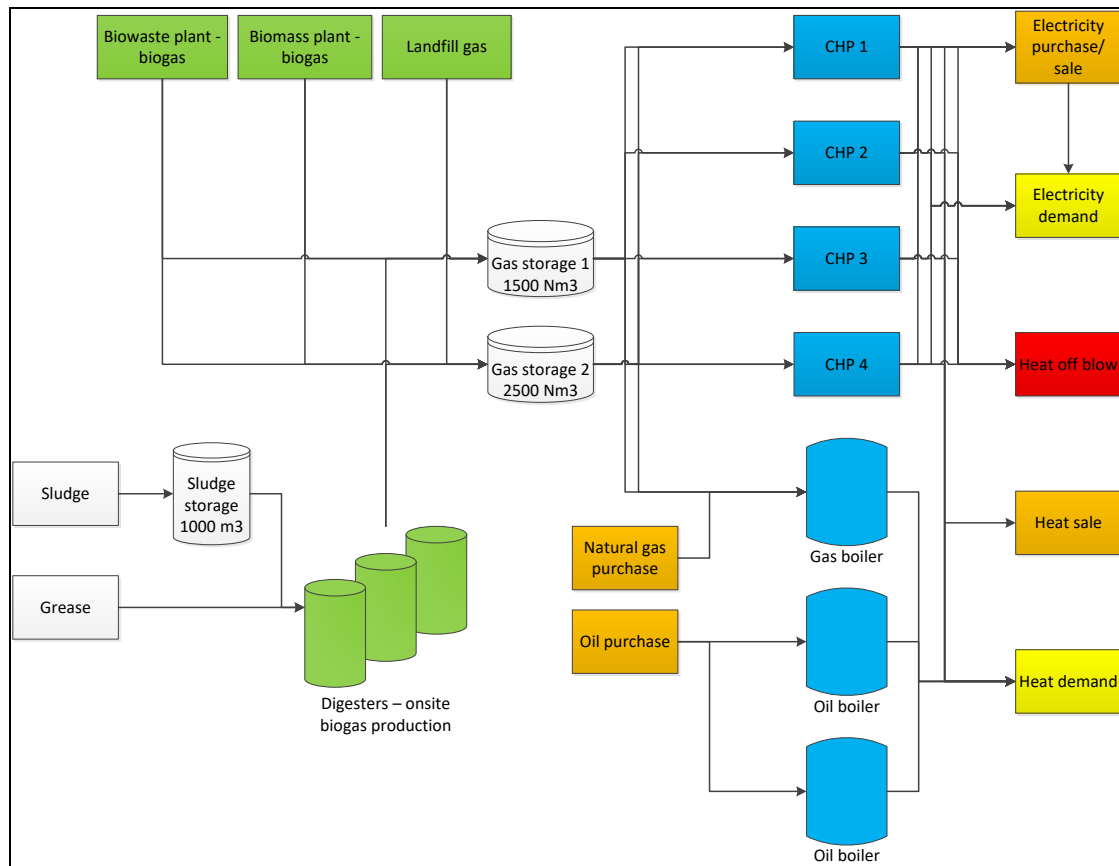
Method:

- Modelling and simulation of energy management at Braunschweig WWTP
- Comparative analysis of different scenario including simulating implementation of new technology or operation principle



1.2. Plant overview

Figure 1 illustrates a simple overview of energy flows that influences the energy management at the WWTP in Braunschweig.



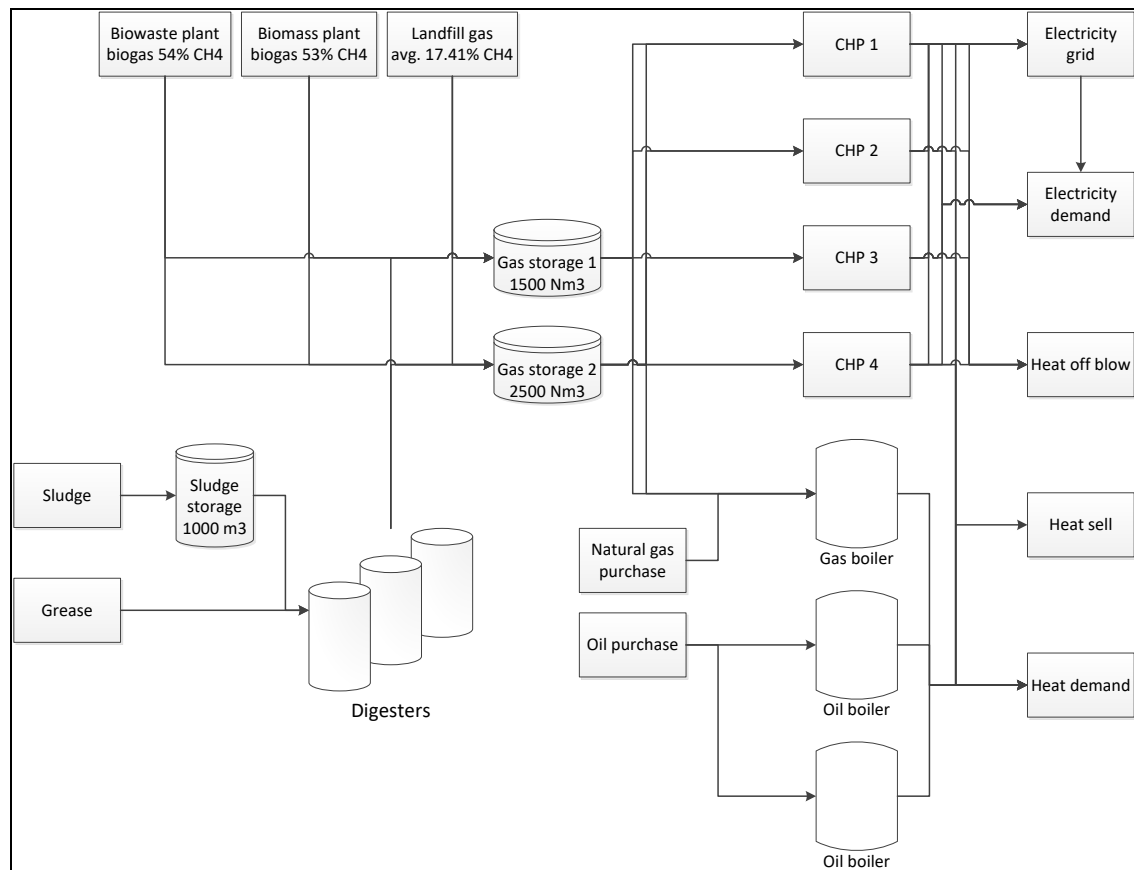


Figure 1: Overview of current energy management at Braunschweig WWTP. The green boxes refer to gas inflows to the storage, orange boxes are energy purchase and sale, blue boxes illustrate energy production from different production units, yellow boxes are onsite energy demand and the red box illustrates that heat is some periods are wasted.

In the daily operation at the plant both heat and electricity are consumed. In

Figure 1, this is referred to as electricity and heat demand. Biogas is produced from sludge and grease in the onsite digesters and supplied to the two gas storage tanks. Additionally, biogas is purchased from a nearby biowaste plant and biomass plant. These sources are also supplied to the gas storage tanks. Finally, landfill gas is supplied to the storage to reduce CH_4 content in the total gas source because the CHP units are most efficient when the methane content in the biogas is approximately 50%. This is special for Braunschweig because they have access to landfill gas. The total gas storage capacity is 4000 Nm^3 and the storage can provide flexibility to the electricity and heat production. Heat is produced onsite from several different units. There are four CHP units that produce electricity and heat. The CHP units run on biogas supplied from the gas storage. Additionally, heat can be produced at the gas boiler or the oil boilers. The gas boiler can either run on biogas from the gas storage or natural gas that is purchased from a gas supplier and taken from the gas grid. The oil boilers are used as back up units for peak hours with high heat demand. The electricity demand is either supplied from the CHP units or purchased from an electricity supplier and supplied from the grid.

In hours of excess electricity production from the CHP units, electricity is sold to the electricity supplier at a fixed price and supplied to the grid. Excess heat is also sold to

nearby heat consumers at a fixed price but the possible heat sale is limited by the local consumers heat demand.

1.3. Production capacities

Figure 2 illustrates the production capacities on the different units at the plant. The four CHP units all have the same capacity of 710 kW_e and 680 kW_t¹. The efficiency of the CHP units (37.4% electrical, 35.8% thermal as useful heat) drops drastically when the generation of electricity drops below 600 kW, so that the CHP units are usually operated at full load. The CHP units use biogas as fuel, while the gas boiler can use both biogas and natural gas as fuel. There are two oil boilers at the WWTP mainly serving as back-up system in case of high heat demand, but they are modelled as one unit with a total capacity of both boilers.

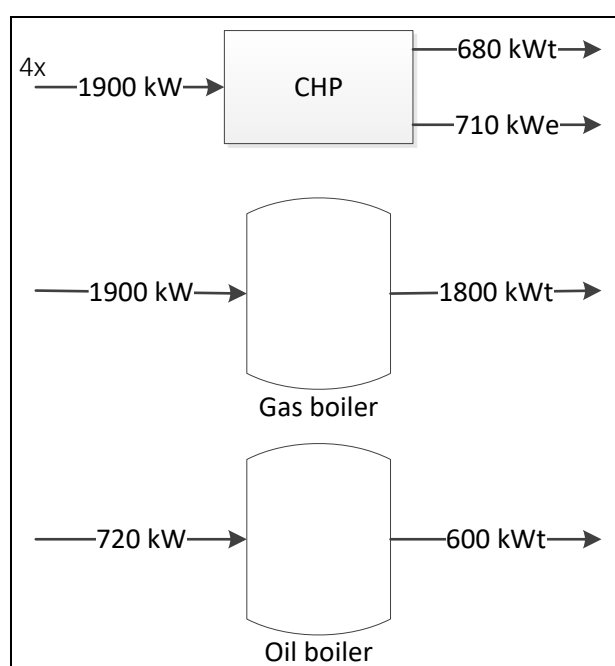


Figure 2: Capacities at the different units for electricity and heat production.

1.4. Biogas storage capacity

As illustrated in

Figure 1, there are two biogas storage tanks with a total capacity of 4000 Nm³. The CHP units in Braunschweig are most effective with methane content in the biogas of 50%, so the landfill gas is used to reduce methane content in the mixed gas to this level. The actual calorific value varies depending on the four gas sources but in the model an average calorific value of 5 kWh/Nm³ is applied to calculate the storage capacity. Hence, 4000 Nm³ of storage volume corresponds to 20.000 kWh of energy content in the gas, assuming that 100% methane has a calorific value of 10 kWh/Nm³.

¹ Capacities informed by Christoph Siemers, Plant Manager at Stadtentwässerung Braunschweig GmbH, 2015.



2. Characteristics of the energy model

A model is developed to simulate the energy management at the WWTP on an hourly basis. Different scenarios are modelled and these will be presented in Chapter 3. Historical figures from the period March 10, 2015 to February 27, 2016, hereafter called the analysed period, are applied. The figures include hourly electricity and heat demand profiles and biogas profiles from biowaste plant, biomass plant and digester production. Actual energy costs, energy taxes and tariffs are also applied from the analysed period.

2.1. Optimisation problem

Basically, the objective is to minimise energy costs at the WWTP. To estimate potential savings of different management scenarios, a model of the energy management system is developed in Matlab, and a solver is applied to determine the optimal operation of the plant. The method used to solve the minimization problem is mixed-integer linear programming (MILP) and Matlab's MILP solver is applied for the purpose.

The solver is given a set of variables, constraints and an objective function. The objective function is a cost function that is minimised, which is linked to the variables (see cost function below). The variables are fuel inputs to the energy producing units at the plant and these consequently influence the total cost of energy. Electricity purchase is another variable which of course has a cost. Waste heat is another variable that needs to be considered because there is a limited possibility of selling heat. This variable is related to a cost because the heat potentially can be sold at a different time.

As an example, heat production from natural gas on the gas boiler will generate a cost because the natural gas must be purchased from the gas supplier. On the other hand, CHP operation avoids electricity purchase and may generate electricity and/or heat sale with a related income. An income is also considered as a negative value in the cost function.

Finally, the constraints are a set of boundaries that are given to the variables. The constraints to the model include technical limitations (capacity limits of production units and storage capacities) and ensure that the electricity and heat demand are fulfilled hour by hour. The solver finds the optimal hourly value for each of the variables that minimises the total energy cost. Basically, the solver tries one solution after the other within solver constraints (changing variables within capacity limits) until the optimal solution is found.

Cost function in fixed and variable price scenario:

$$\begin{aligned} \text{sum}(Pel * Cel - (Pel + Fchp * Eel - Del) * Rel + Fng * Cng + Fob * Co \\ - (Fchp * Ehe + (Fbb + Fng) * Egb + Fob * Eob - Obhe - Dhe) * Rhe \end{aligned}$$

Variables in fixed and variable price scenario:

Fchp Upper bound = 4. Number of CHP unit activated. Modelled as on/off (0 or 1).

Fbb Upper bound = 1900. Biogas input (kW) to gas boiler.

Fngb Upper bound = 1900. Natural gas input (kW) to gas boiler.

Fob Upper bound = 720. Oil input (kW) to oil boiler.



Obhe Upper bound = infinite. Heat off blow (kW).

Pel Upper bound = infinite. Electricity purchase (kW)

Lower bound is 0 for all variables.

Other factors in cost function:

Cel Cost electricity

Eel Efficiency electricity (CHP)

Del Demand electricity

Rel Revenue electricity sale

Cng Cost natural gas

Co Cost oil

Ehe Efficiency heat (CHP)

Egb Efficiency gas boiler

Eob Efficiency oil boiler

Dhe Demand heat

Rhe Revenue heat sale

The outputs from the model are hourly fuel inputs to the production units, energy outputs calculated from the efficiencies of the generating processes (i.e. CHP or boiler), energy output from storage, storage content, and energy costs and revenues. A comparison of the costs and revenues in the different scenarios creates the basis for the recommendations of an optimised energy management with lowest energy costs.

2.1.1. Energy forecasts

Two of the constraints to the model are to fulfil electricity and heat demand at all times. The model optimises 48 hour (2 days), after which the model steps one day and does another 48-hour optimisation. The second day in one optimisation becomes the first day in the following optimisation. In total, 355 optimisations are made to analyse the entire period of 355 days. This approach simulates a perfect 48-hour hourly forecast of the heat and electricity demand at the plant plus biogas production. However, using historical figures for the model calculations corresponds to assuming a perfect energy forecasts, which is a major assumption to the model. Today, no forecast is made for heat and electricity demand at the WWTP in Braunschweig. A real forecast will not be perfect and the potential cost savings is likely lower in a real scenario. Hence, it is a best-case approach used in the model but it is estimated as the best approach since no historical prognoses exist. The purpose of forecasting the energy demand is to have a better utilisation of the biogas storage by adjusting energy production to consumption and thereby minimising energy purchase.

2.1.2. CHP operation

The four CHP units are modelled as on/off to operate at full load only and prevent the drastic drop in efficiency when the fuel input decreases. Consequently, the electricity and heat is generated in four steps of 710 kW_{el} and 680 kW_t, respectively, corresponding



to the number of CHP units that are turned on (see Figure 3). The fuel capacity of each unit is 1900 kW.

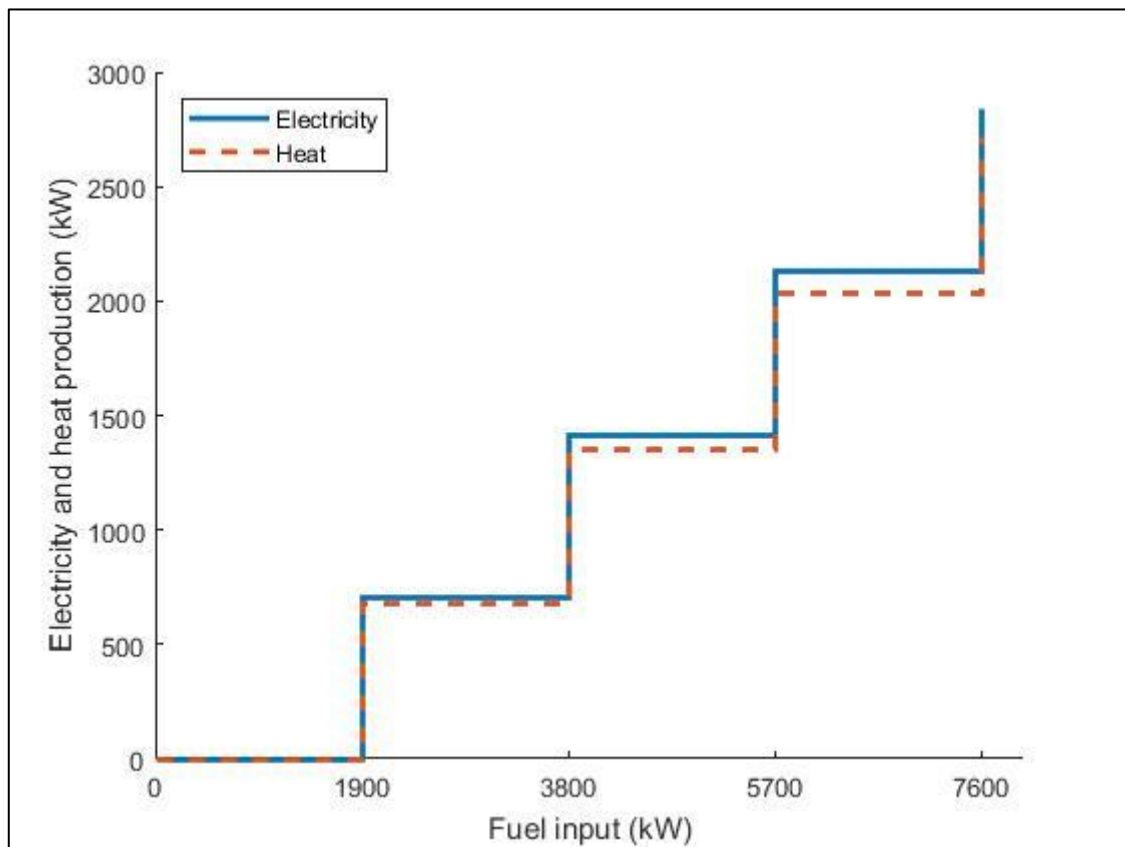


Figure 3: Electricity and heat production from the CHP units as a function of biogas fuel input modelled as on/off.

2.2. Historical input profiles

The model simulates the operation of the plant on hourly basis. As described in Chapter 1, there are several sources of gas coming to the plant. An accumulated biogas production profile is made and modelled as an hourly energy input in kWh to the gas storage based on the historical figures for the period. The biogas profile and energy demand profiles are the same in all the modelled scenarios to have a fair basis for comparison.

Figure 4 illustrates the monthly energy input to the biogas storage from the different sources in the analysed period.

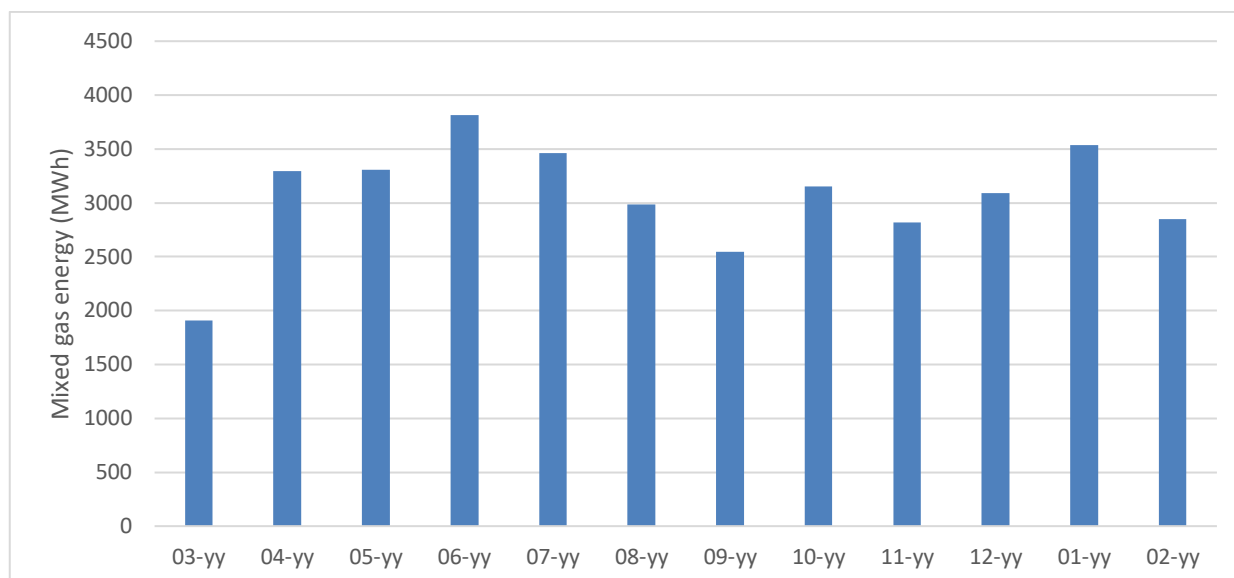


Figure 4: Monthly energy content of input gas (March 2015: 20 days only).

It should be noticed that the analysed period begins at the 10th of March, which is why the energy content is significantly lower in March. The total energy content from the different gas sources is 36,681 MWh in the analysed period.

The heat and electricity demands are based on the actual hourly consumption data measured in the period analysed. Figure 5 illustrates the average hourly electricity and heat demand in the analysed period e.g. the average electricity demand in the hour from 00:00-01:00 of all days in the period. This gives an impression of which time of the day there is a larger need for energy. Furthermore, the energy demands at December 12th, 2015 are illustrated. The electricity demand peaks December 12th, 2015 from 01.00-02.00 at 2571 kWh.

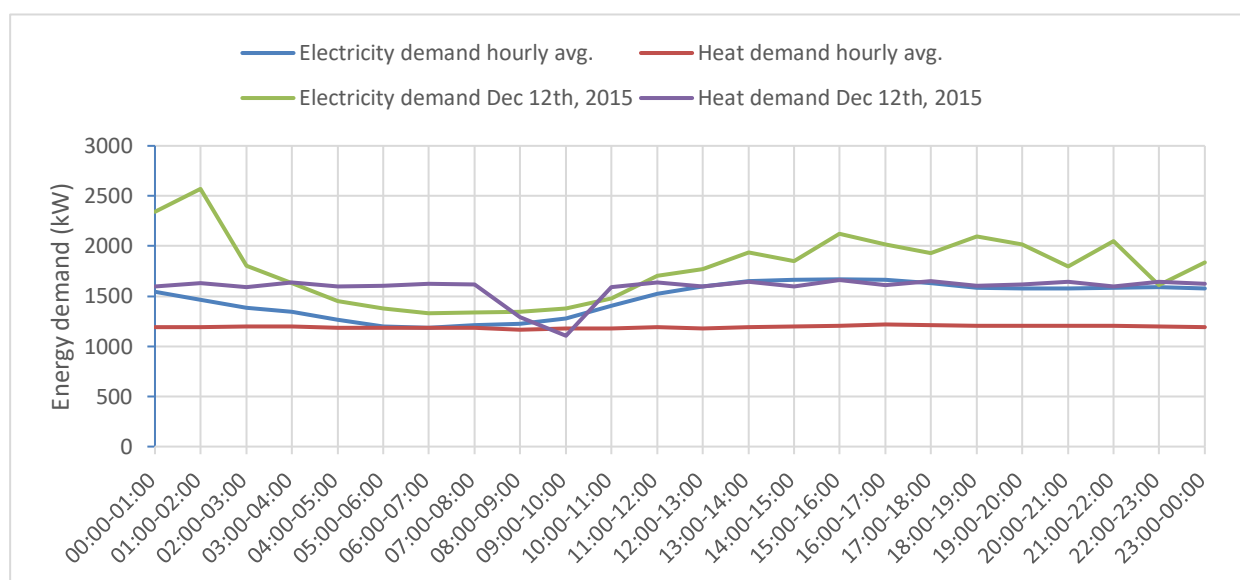


Figure 5: Average hourly electricity and heat demand in the analysed period.

The average hourly heat demand is constant around 1200 kWh/h. The average electricity demand is higher in the afternoon compared to average demand during night and



morning hours. The annual heat and electricity demand is 10,166 MWh and 12,565 MWh, respectively, in the analysed period.

2.3. Energy costs and revenues

This section describes the energy costs and revenues from buying and selling the different sources of energy. The purpose of the model is to minimise energy costs by optimising the energy management at the plant.

2.3.1. Biogas cost

Three sources of biogas are delivered to the biogas storage tanks. The biogas produced onsite is free of charge. The other two biogas sources come from a nearby biomass and a biowaste plant. In accordance with the agreement, Braunschweig WWTP is to take all the biogas produced at the plants at a fixed price. Therefore, the volume of biogas from the biomass and the biowaste plant is not a parameter to optimise. Under these conditions, the cost of biogas will be the same for all scenarios. And therefore, the cost of the biogas is excluded from the analyses. The landfill gas is also considered free of charge.

2.3.2. Electricity cost

The electricity price consists of different price components. Besides the cost of the product (electricity), tax, levies and VAT are also paid for consuming electricity. Table 1 illustrates the different price components for consuming power at Braunschweig WWTP.

Table 1: Electricity price components².

Price component	EUR/MWh
Energy price	52.60
Grid fee	30.20
EEG fee	63.54
Electricity tax	15.77
Concession fee	1.10
Miscellaneous fees	8.63
VAT	32.65
Sum	204.49

The cost for consuming electricity in the fixed price scenarios (see Chapter 3) is 204.49 EUR/MWh. The fixed price creates no incentive for purchasing power in some hours compared to others. In the market scenarios, the energy price is not fixed but is the actual hourly EEX spot price. This results in a volatile electricity price that creates incentive for purchasing electricity in hours where the electricity price is low. The average EEX spot price in the analysed period is 30.57 EUR/MWh, which is significantly lower than the fixed energy price of 52.60 EUR/MWh. The fixed price is based on a long-term contract with the

² Price data provided by Christoph Siemers, Plant Manager at Braunschweig WWTP



electricity supplier. This significant difference in prices needs to be taken into account when comparing fixed price and market price scenarios.

The EEX spot market is a day-ahead market where bids are submitted the day before the coming day. If sold electricity is not supplied to the grid, an imbalance is created. The imbalance is settled by an imbalance cost (reBAP price). As this model analysis is based on historic data there is no imbalance cost.

Figure 6 illustrates the average hourly spot price of all days in the analysed period.

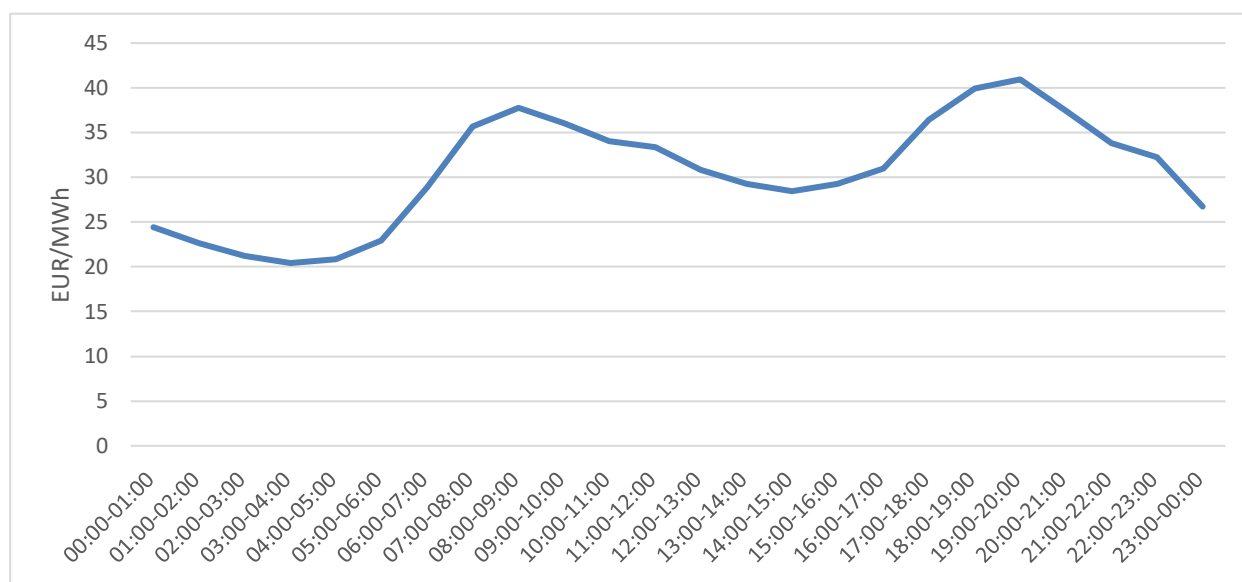


Figure 6: Average hourly spot price in the analysed period.

The figure illustrates that general pattern of the electricity price with a morning and early evening price peak. The price peaks are generated by an increase of the overall electricity consumption in these periods. This is average prices but the individual day may look different and the individual hourly price is considered in the market price scenarios.

2.3.3. Electricity sale

If electricity production exceeds electricity consumption the excess power is sold to grid and settled by the local grid company. Electricity is currently sold at a fixed price under the 2004 EEG program, in which electricity produced from biogas is guaranteed a fixed price of 120 EUR/MWh and electricity produced from sewage gas (biogas produced from sewage sludge) is guaranteed a fixed price of 77 EUR/MWh. Based on the composition of biogas and sewage gas a fixed mean price of 91.87 EUR/MWh was paid for the electricity sold in the analysed period. This price is used in the fixed price scenario for the electricity sold to the grid.

In the market price scenarios, it is assumed that the plant is enrolled in the direct marketing (Direktvermarktung) program under the EEG Marktprämienmodell, which is defined here as "market conditions". It is possible to move from EEG to direct marketing without a financial disadvantage.

At market conditions electricity is sold at the market price plus a market premium, which is an extra payment on top of the market price. The market premium is calculated each month and is the difference between EEG payment and the average monthly market



price. Figure 7 illustrates the monthly market premium calculated from EEG and monthly average spot price³ in the period March 2015 to February 2016.

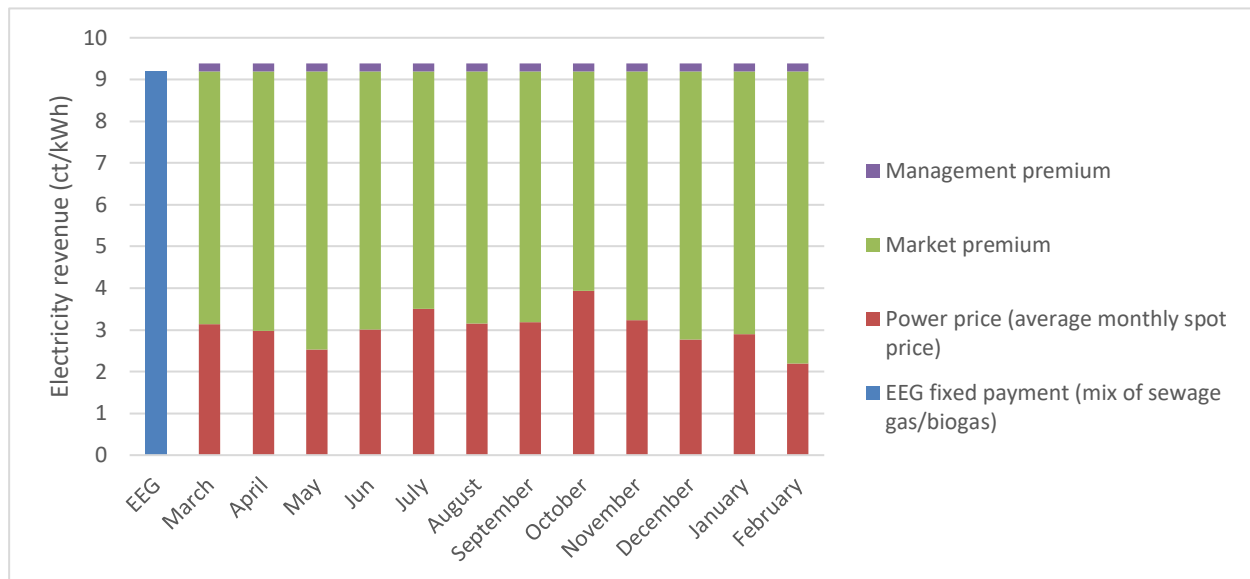


Figure 7: EEG fixed price and market price conditions at direct marketing.

The average monthly power price is not equal to the sales price in the market price scenarios. Electricity sale is settled at the hourly spot price for the hour in question.

On top of the market premium it is possible to have a management premium (2 €/MWh) to compensate for management costs of direct marketing (e.g. remote control of CHP from a BRP).

2.3.4. Prognosis for electricity spot price

The spot market is a day-ahead market where bids are submitted the day before. In a real-life scenario, a spot prognosis predicts the electricity price hour by hour for the coming day which is used for the planning of operation for the coming day. In the market price scenarios, Neas Energy's EEX spot prognosis for the analysed period is used for the optimisation i.e. the operation of the different energy producing units. However, the actual settlement of electricity purchase and sale is based on the actual spot price in the period. This simulates a more realistic operation planning.

2.3.5. Natural gas cost

Natural gas is purchased to produce heat on the gas boiler in periods where it is not possible to produce the entire heat demand from the CHP units. The total price for natural gas in the analysed period is 44.33 EUR/MWh⁴, and this price does also apply for the model.

³ Average spot price in analysed period called MW steuerbar:
<https://www.netztransparenz.de/EEG/Marktpraemie/Marktwerte>

⁴ Price data provided by Christoph Siemers, Plant Manager at Braunschweig WWTP



2.3.6. Oil cost

Oil is used for the backup oil boilers during peak hours with high heat demand. The oil is stored in oil tanks at the plant and when the tanks are nearly empty new oil is ordered at the best price possible. In the model, a price of 0.6 EUR/l³ (43 EUR/MWh) is used which corresponds to the actual cost paid in the period of the simulation.

2.3.7. Heat sale

In some periods, additional heat is produced at the WWTP. Heat is sold to nearby consumers but the heat sale is limited by the consumers heat demand and therefore it is not all excess heat that can be sold. In the model, the maximum hourly heat sale is equal to the actual heat sold in the analysed period, assuming no additional demand of heat in the local market. A weighted average price of 18.55 EUR/MWh³ is applied for all heat sale.

2.3.8. Green gas sale

A P2G plant can produce green gas, which can be sold to the gas grid. One of the scenarios analyses the value of implementing a P2G plant at the WWTP to produce biomethane (see scenario description in Chapter 3). Biomethane is assumed to have sales price of 70 EUR/MWh⁵.

⁵ Price information from Electrochaea, June 2017.



3. Scenarios

Different scenarios are developed to simulate how intelligent operation and new technology influences the total energy cost of operating the plant for one year.

The final recommendations for WWTP operators are based on a comparative analysis of the total energy costs generated in the different scenarios. Furthermore, the costs will also be compared to the actual energy costs generated in the analysed period. In this chapter the different scenarios are presented.

3.1. Actual operation

The costs include electricity, natural gas and oil purchase and revenues generated from electricity and heat sale. Today, the operation of the CHP units can be set for three different modes: 1) fulfil electricity demand, 2) fulfil heat demand, 3) run in relation to biogas in storage based on the conditions at the plant. All three modes are based on meeting real time demand because no energy prognoses are made.

3.2. Modelled scenarios

In contrary to the actual operation, it is assumed that the electricity and heat demands are known two days ahead, which in the model corresponds to perfect prognoses of energy demands. Making energy forecasts will be a new thing to implement in the daily operation of the plant. Energy forecasts create the basis for a better utilization of the biogas compared to how the CHP units are operated today. The analysis can thus illustrate potential benefits of having energy prognoses.

In some scenarios (market price scenarios), a market price for electricity is used instead of a fixed price that is present today. Variable market prices are another aspect to consider in the optimisation.

The scenario can be divided in following groups:

1. Energy marketing (fixed and market price scenario)
2. Flexibility (Flexible centrifuges, heat storage and biogas storage scenario)
3. New technology (TEG and P2G scenario)

Figure 8 illustrates an overview of Braunschweig WWTP highlighting the technologies and concepts that are analysed in red boxes. A comparative analysis is made for the modelled scenarios to estimate the potential of implementing new technology or smart operation concepts. The energy cost difference in the scenarios can determine the economic benefits of the implementation.



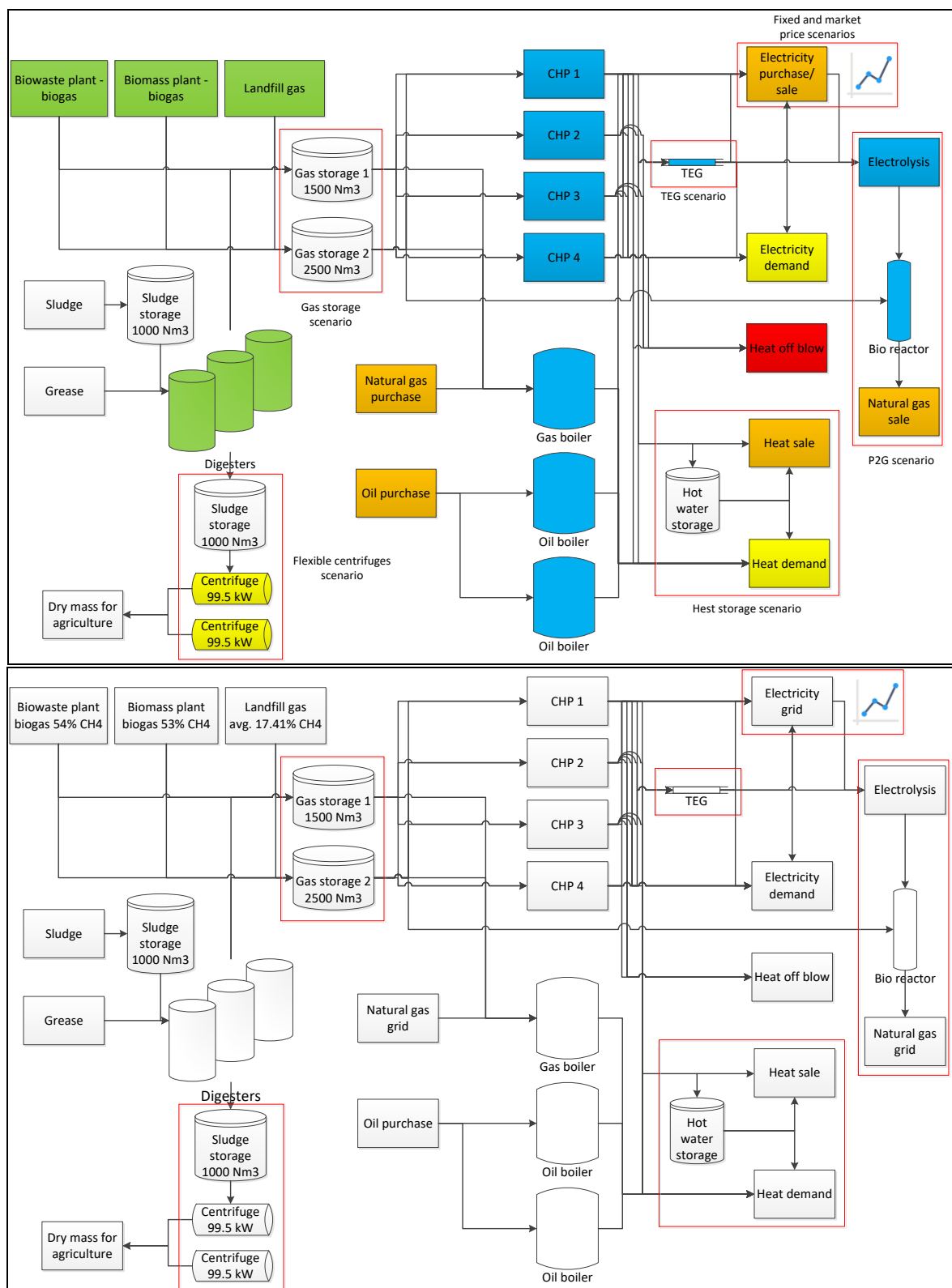


Figure 8: Overview of WWTP highlighting new technologies or intelligent operation concepts. Green colour refers to gas inflows to the storage, orange boxes are energy purchase and sale, blue boxes illustrate energy production from different production units, yellow boxes are onsite energy demand and the red box illustrates that heat is some periods are wasted.



3.2.1. Fixed price scenario

The fixed price scenario is a simulation of the plant as it looks today under current framework conditions (see

Figure 1). In this scenario, the electricity purchase and electricity sale prices are both fixed but the energy management is still optimized with the principle of minimizing the energy costs.

3.2.2. Market price scenario

In this scenario, the system is like the fixed price scenario but the electricity purchase and sale prices are variable hourly market prices i.e. the hourly EEX spot price. The variable market prices give another aspect to optimize compared to the fixed price scenario.

3.2.3. Flexible centrifuges scenario

In this scenario, the operation of the two centrifuges that drain the degassed digested sludge is optimized to minimise electricity costs. The 1000 m³ sludge storage makes it possible to postpone operation of the centrifuges. Each of the centrifuges has a capacity of 99.5 kW_e and a sludge capacity of 40 Nm³/h. In the model a sludge inflow profile is made to simulate the flow of sludge from the digester to the sludge storage. The profile is linked to the input of sludge and grease to the digester. The sludge from the digester going into the sludge storage is modelled as an hourly value. Figure 9 illustrates the setup.

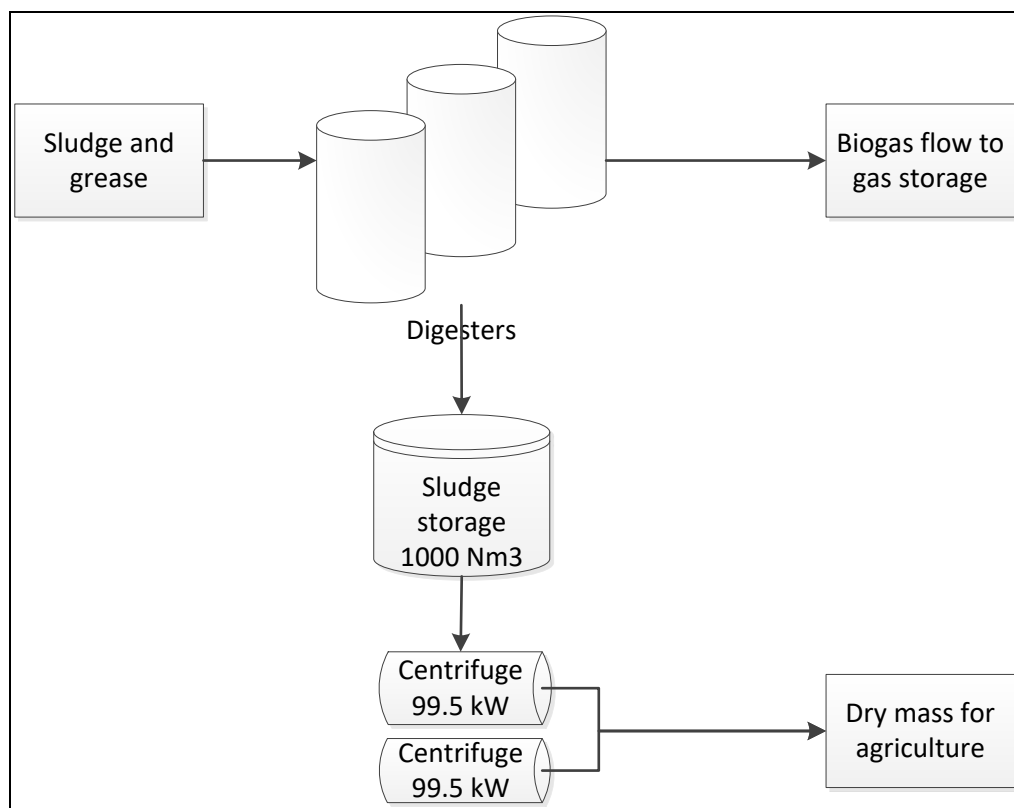


Figure 9: Overview of centrifuges that provides consumption flexible.

The centrifuges consume 463 MWh electricity/year to treat all the sludge, which corresponds to 3.8% of the total annual electricity demand. In the flexible centrifuge

scenario, the hourly electricity demand is reduced by 3.8% to have the same total electricity consumption in all scenarios. In other words, 3.8% of the electricity demand is operated flexible.

3.2.4. Heat storage scenario

In the heat storage scenario, it is assumed that a heat accumulation tank of 2000 kWh is built at the plant. The heat storage is assumed to be connected to the CHP units. The CHP units are modelled as on/off and by implementing a heat storage it is possible to generate some flexibility on the heat side. The heat storage is relatively small compared to the heat demand. The capacity of the storage is just above 1.5 times the average hourly heat demand, which generates many cycles of the storage. Therefore, no energy loss is assumed to be associated with operation of the storage. Hence, it is a best-case scenario.

3.2.5. Biogas storage scenario

The biogas storage gives the flexibility to postpone operation of the CHP units and gas boiler. In the biogas scenario, it is assumed that the current biogas storage capacity is doubled from 4000 Nm³ to 8000 Nm³, i.e. 40,000 kWh in total. A larger storage capacity may generate a better utilisation of the biogas because it increases the flexibility on the CHP units.

3.2.6. Thermo-electric generator (TEG) scenario

One of the smart goals of WP3 is to increase electricity production using TEG modules that convert heat flux to electricity by utilizing exhaust gas from the CHP units (see D3.3 for detailed explanation of TEG). In the TEG scenario, a full scale TEG case is analysed assuming four TEG modules each with an input heat capacity of 367 kW_t. This corresponds to the maximum usable heat output from the exhaust gas of the CHP units, not considering any system losses. In this best case analysis additional 12.8 kW_e shall be generated from the thermal power input and the rest of the thermal energy shall be returned as 354.2kW_t usable heat.

Figure 10 illustrates the capacity of one best case full-scale TEG module.



Figure 10: Capacities for one full scale TEG module⁶.

3.2.7. Power-to-gas (P2G) scenario

The P2G plant consists of an electrolyser that produces hydrogen and a bioreactor in which biomethane is produced. The hydrogen is fed to the bioreactor along with a source of CO₂ coming from the biogas. Living microorganisms feed on hydrogen and carbon dioxide while producing methane, which is the main component in natural gas.

⁶ Capacity information from Fraunhofer IPM, 2017



By converting the carbon dioxide into methane, the biomethane can be injected in the gas grid after post-treatment to guarantee a suitable gas quality (e.g. drying, removal of impurities). This technology is called biological methanation.

The electrolyser consumes electricity, which can be produced at the CHP units or taken from the electricity grid. When running the P2G plant biogas is supplied to the bioreactor. The biomethane is assumed to be sold to the grid and cannot be used to fuel the CHP units. Electricity demand for pumps and a high-speed mixer in the bioreactor is included in the electrical capacity of the electrolyser. Figure 11 illustrates the P2G plant.

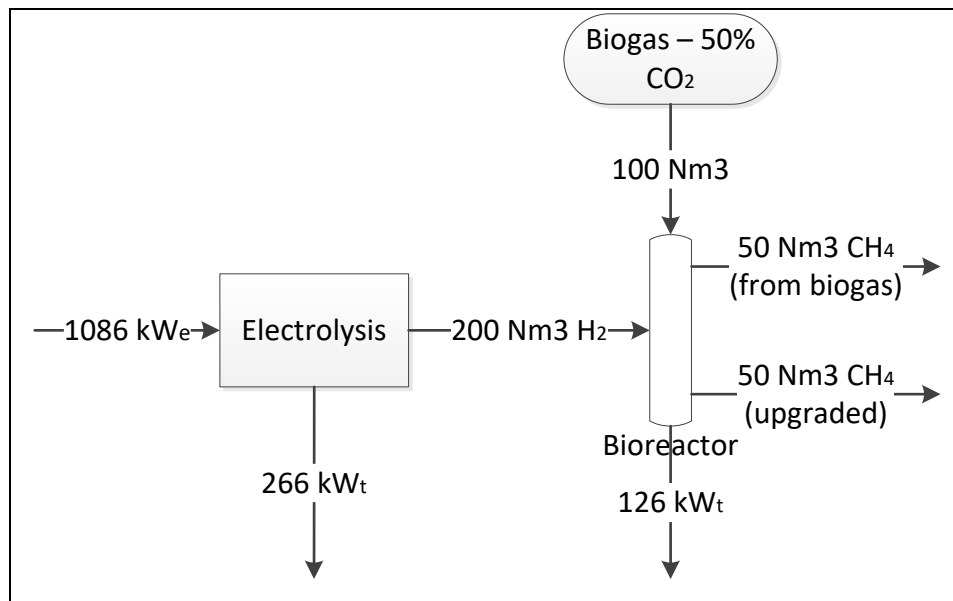


Figure 11: Electrolyser and bioreactor capacity.

3.3. Summary of scenarios and investment costs

Table 2 sums up the different scenarios with their individual specifications. The TEG, P2G, Flexible centrifuges, Heat storage and Gas storage scenarios are all analysed both with a fixed electricity price and market price. Investment cost of new technology is also presented in the table.

Table 2: Specification of the individual scenario.

Scenario	Specification/smart grid concept	Investment cost
Fixed price scenario	Energy prognoses implemented. No new technology. Fixed electricity cost and electricity sales price.	
Market price scenario	Energy prognoses implemented. No new technologies. Variable electricity cost and sale prices (market price).	
Flexible centrifuges scenario	Energy prognoses implemented. No new technologies but centrifuges operated flexible corresponding to flexibility in 3.8% of total electricity demand.	
Heat storage scenario	Energy prognoses implemented. Heat accumulation tank implemented to utilize	Heat storage tank:

	excess heat production. Best case with no heat losses.	2000 kWh: 53,300 EUR ⁷
Biogas storage scenario	Energy prognoses implemented. Additional biogas storage capacity implemented (4000 Nm ³) to increase flexibility for CHP operation.	Gas storage tank: 4000 Nm ³ : 680,000 EUR (170 EUR/Nm ³ – zero pressure storage) ⁸
TEG scenario	Energy prognoses implemented. Four TEG modules with 12.8 kW _e each implemented to increase electricity yield. Best case operation assumed.	TEG unit: 40,000 EUR/unit (3 EUR/W _e) ⁹ Total: 160,000 EUR
P2G scenario	Energy prognoses implemented. P2G plant (1 MW _e) implemented that allows upgrading biogas and sell biomethane to the gas market.	Electrolyser: 700,000 EUR Methanation incl. project management: 1,686,000 EUR ¹⁰ Total: 2,386,000 EUR

⁷ Price information from Veolia, January 2017.

⁸ Price information from Stadtentwässerung Braunschweig GmbH, June 2017.

⁹ Price information from Fraunhofer IPM, June 2017.

¹⁰ Price information from Electrochaea, June 2017.



4. Results of scenarios for optimised energy management

In this chapter the outputs from the different scenarios are analysed to assess how to achieve an optimal energy management. The optimised scenarios are also compared to the actual operation in the analysed period in terms of total cost for energy.

4.1. Optimised energy management and energy production priority

The variables are prioritized in relation to their cost intensity by the optimisation algorithm. Six of the variables are identical in all the scenarios and to illustrate the priority they are listed in relation to how cost intensive they are: 1) electricity purchase 2) oil boiler operation 3) natural gas boiler operation 4) heat off blow 5) biogas boiler operation and 6) CHP operation. The most cost intensive variable is electricity purchase and the solver tries to avoid this by adjusting electricity production to consumption. The constraints and input profiles (biogas profile and energy demand profiles) limits the use of the different production units.

Another, 1-2 variables are added to the following scenarios: TEG scenario – heat input for TEG module, P2G scenario – electricity consumption on electrolyzer, Flexible centrifuges scenario – sludge input to centrifuges and Heat storage scenario – heat charge and discharge. A cost for each of the variables is calculated and the priority is generated based on the cost intensity as mentioned above.

4.2. Hourly energy management

As mentioned, the hourly heat and electricity demand needs to be fulfilled at all times. Figure 12 and Figure 13 illustrate how the electricity demand is fulfilled hour by hour for two days (18th-19th of May, 2015) in the fixed price and market price scenario, respectively. In the market price scenario, the variable price factor is considered in the optimisation. In the fixed price scenario (Figure 12) the gas storage content is illustrated as the red line and in the market price scenario (Figure 13) the spot price is illustrated on the second y-axis. The storage content is also considered in the market price scenario but it is not illustrated in the figure because the spot price is illustrated on the second y-axis.

The first y-axis illustrates power in steps of 710 kW, which is the electrical capacity per CHP unit. The CHP units is modelled as on/off. The blue line is the hourly electricity demand that is fulfilled either by own consumption or electricity purchase. Excess electricity is sold to the grid.



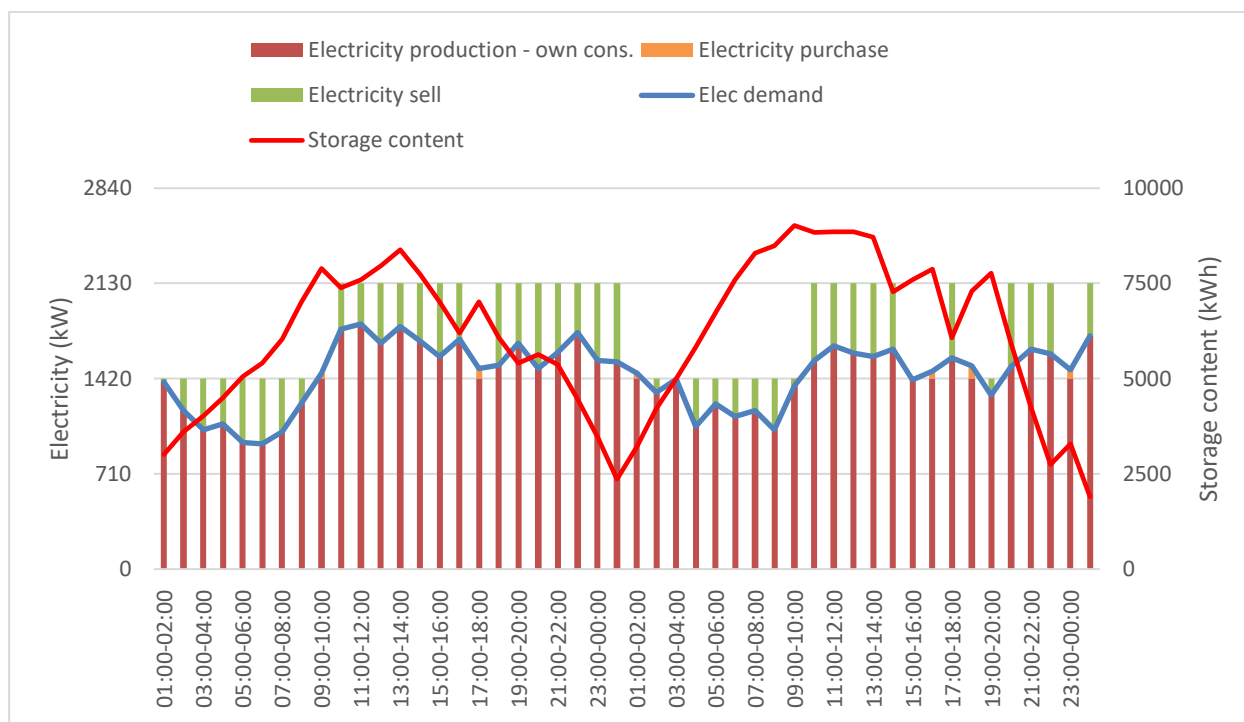


Figure 12: Hourly electricity supply on May 18-19, 2015 in the fixed price scenario.

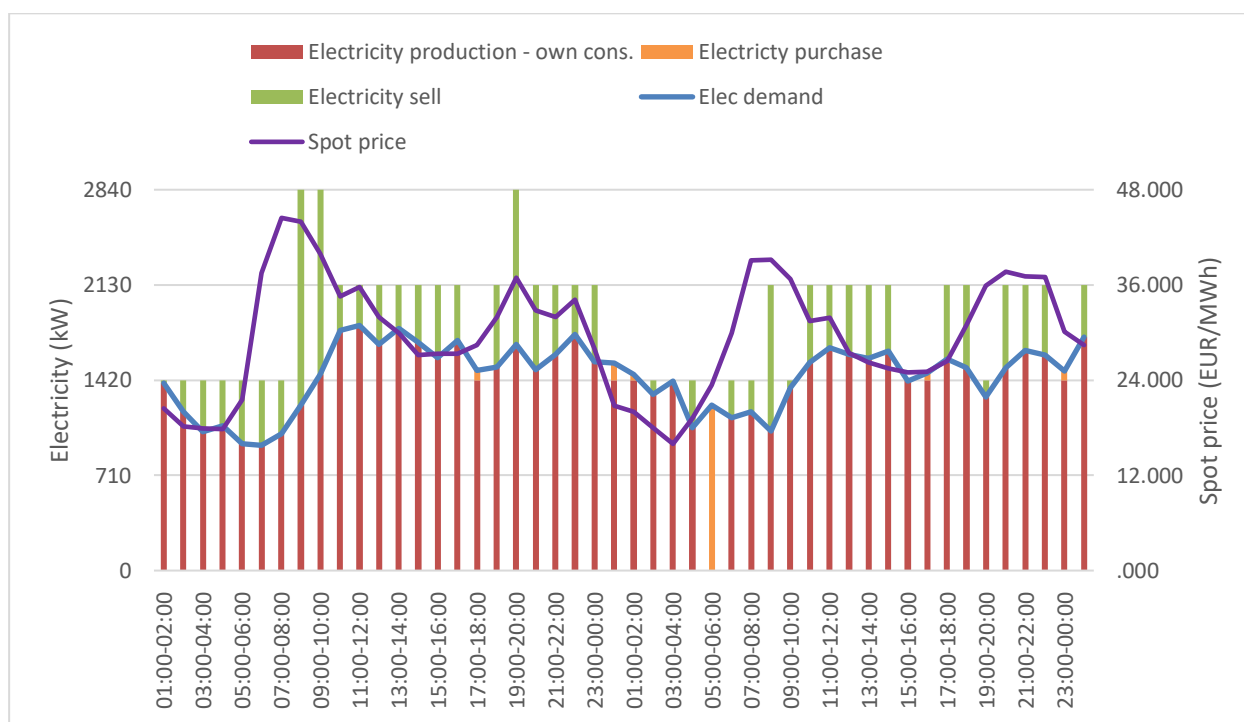


Figure 13: Hourly electricity supply on May 18-19, 2015 in the market price scenario.

In the fixed price scenario, two or three units are operated throughout the 48 hours. It is clear to see that electricity production is adjusted to electricity consumption. Three units are operated when the electricity demand is higher and 2 units when it is lower. In general, the storage content increases when two units are operated and it decreases when three units are operated. It is not worth to operate four units and sell more power compared to saving the biogas for the next day.



In the market price scenario, the production is also adjusted to the consumption. However, the variable electricity price is another factor that is considered in the optimisation. During the same two days, 0-4 units are operated in the single hour throughout the 48 hours. Four units are operated in hours with relatively high electricity demand and high electricity price and vice versa for the single hour where all units are shut off. Nevertheless, the operation of the CHP units is rather constant (2-3 units) which is due to the high fixed cost on electricity. This operation regime could change in a scenario with a high variable electricity cost.

4.3. Annual energy management

Figure 14 illustrates the electricity balance on a yearly basis in the different scenarios. MP means the scenario is analysed with a variable electricity market price.

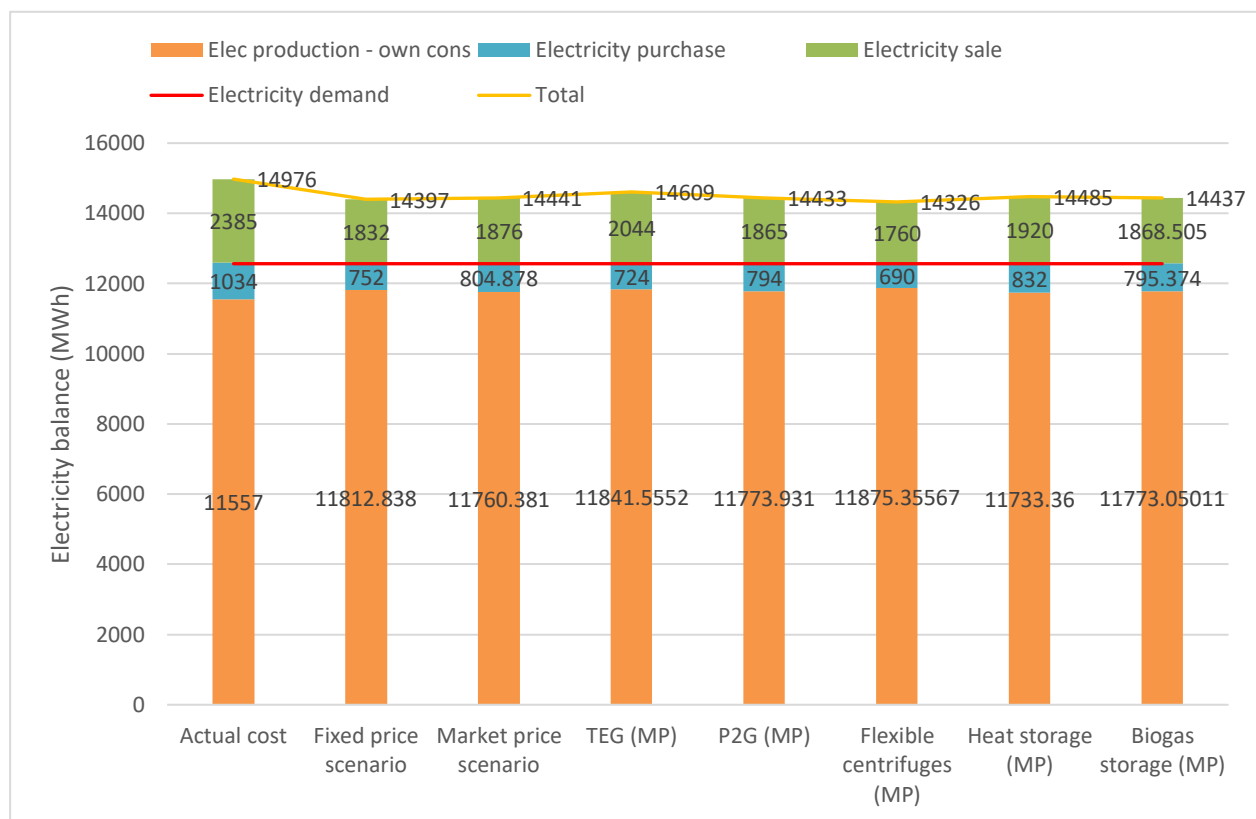


Figure 14: Annual electricity balance in the different scenarios.

Most of the electricity consumption is produced onsite from the CHP units (94-95%) in the optimised scenarios. The total amount of electricity sold to the grid is higher than the total electricity purchase but it is not possible to adjust production and consumption completely as the CHP units are operated as on/off units in the model. Furthermore, the production of biogas limits the operation of the CHP units. In the optimised scenarios, the electricity purchase and sale are lower than in the actual period due to a better adjustment of electricity production and consumption increasing the own consumption. When combining market prices with flexibility options or new processes, there are small variations. In the TEG scenario the electricity sale and own consumption is higher. This is



because the four TEG units produce an additional 241 MWh/year of electricity, which can be either used for own consumption or sold to the grid.

In the flexible centrifuges scenario, the own consumption is the highest (60-100 MWh higher than the other scenarios) because flexible operation of the centrifuges makes it possible to adjust electricity production and consumption even better. In the heat storage scenario, the own consumption is lowest (40-140 MWh higher than other scenarios) among the market price scenarios. This indicates that optimising the heat side in some hours is more valuable than the electricity side.

Figure 15 illustrates the heat balance on yearly basis in the different scenarios.

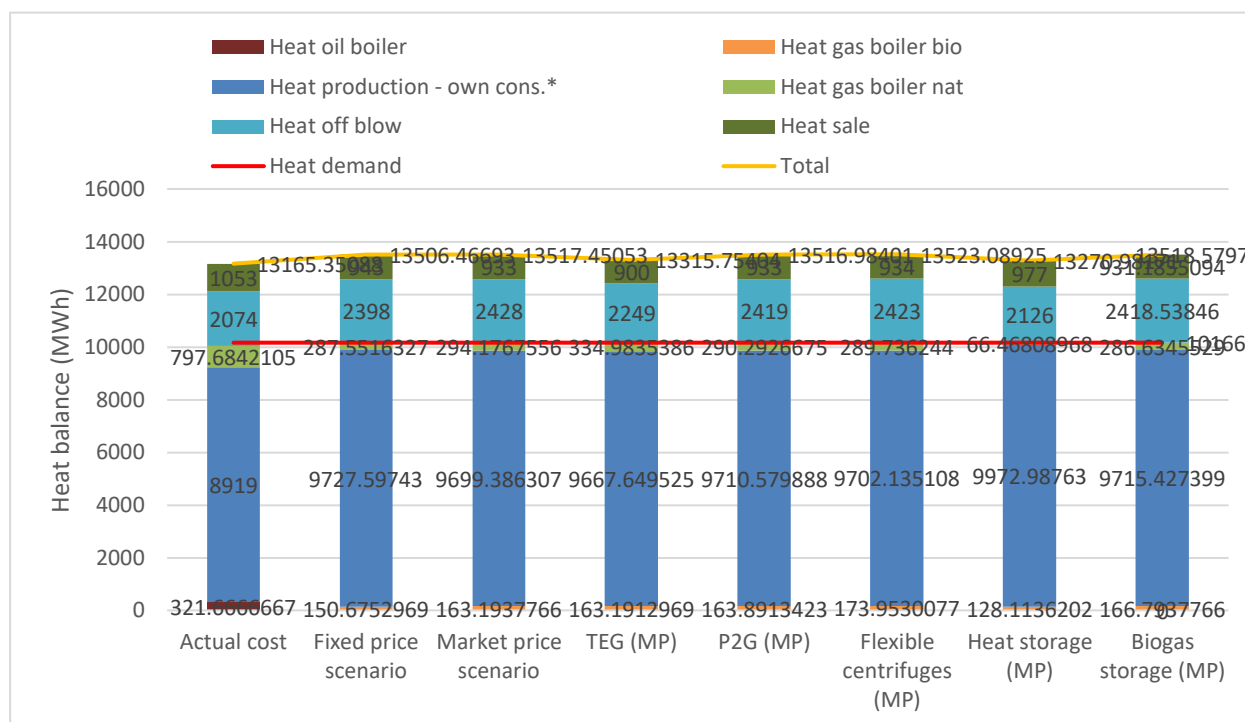


Figure 15: Annual heat balance in the different scenarios.

The CHP units produces most of the heat consumption. Waste heat is only generated from CHP operation. Heat production at the gas and oil boiler is limited and it is not profitable to operate the boilers to sell heat. Boiler operation does only occur when the CHP units cannot deliver the heat demand. Heat production on the oil boiler is completely avoided in the optimised scenarios.

4.4. Energy cost savings and simple payback time

Annual energy costs and revenues generated in the scenarios are compared to estimate the value of implementing new technology or new management solutions. Figure 16 illustrates annual revenues and costs from energy sale and purchase in the different scenarios, which are elaborated in the following sections.



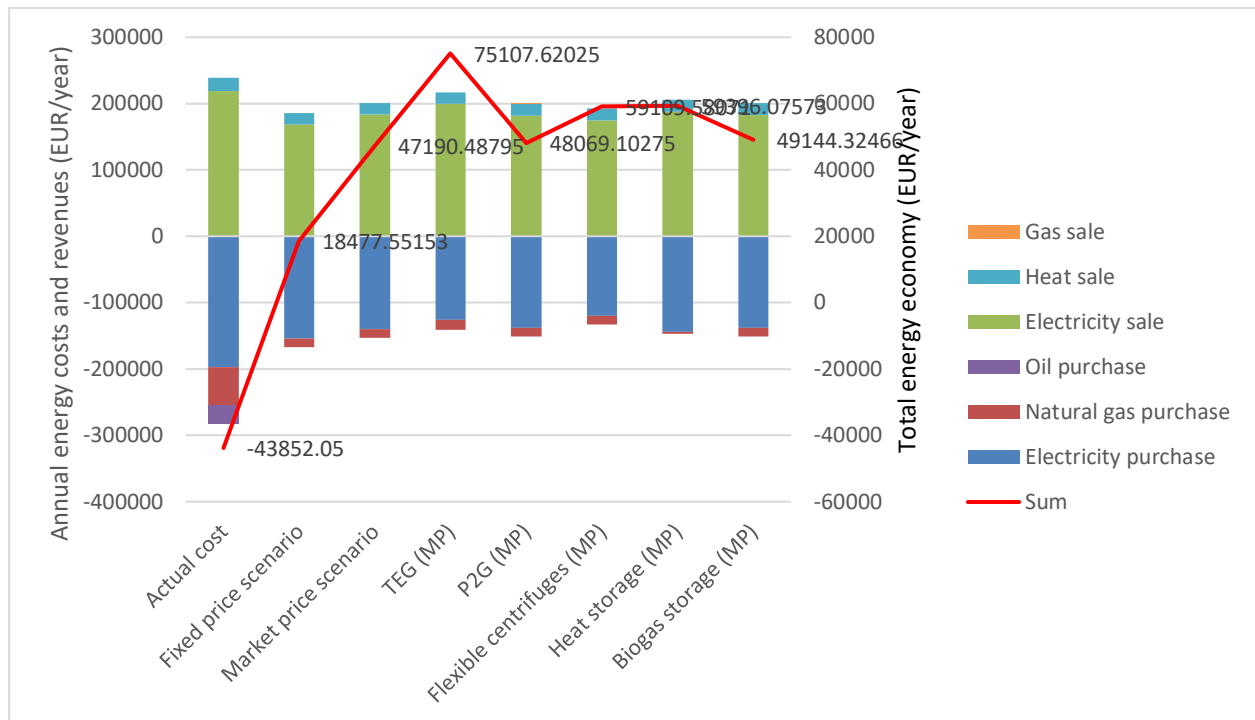


Figure 16: Annual energy costs and revenues in the different scenarios.

4.4.1. Fixed and market price scenario

In all the scenarios, by working with historic data, it is assumed that electricity and heat demand are known in a period of 48 hours in the future. Particularly, the electricity forecast is important in the view of optimising the energy management at a WWTP as the electricity purchase price is high. At the WWTP today, there is no forecast of the energy demands, so the CHP units are only operated in relation to real time demand.

The actual costs generated in the analysed period are compared to the cost generated in the fixed and market price scenario (see Table 3). Hence, this comparison estimates the maximum value of having energy forecasts, here assuming a perfect prognosis by using historic data. Cost savings refer to the economic benefit of implementing the scenario. Red means savings and black is an additional cost.

Table 3: Actual costs and costs generated in the fixed price and market price scenario.

Scenario	Total energy costs (EUR/year)	Cost savings (EUR/year)
Actual	-43,852	
Fixed price scenario	18,478	62,330
Market price scenario	47,190	91,043

The actual energy cost in the analysed period is -43,852 EUR. Comparing actual costs to model simulations may create some uncertainty because this model does not take unforeseen events into account (for example break down on a CHP unit). To validate the model, the fixed price scenario is also modelled with 2-hour energy forecasts that may simulate actual forecast conditions better than using the optimum 48-hour forecasts. The



total energy cost in this scenario is -48,002 EUR, which is in the magnitude of the actual costs. However, it is expected to be lower than the actual costs because the plant manager may have knowledge of the near future development.

The estimated savings is more than 60,000 EUR/year in the fixed price scenario and more than 90,000 EUR/year for the market price scenario. This indicates that a better energy management can be achieved from forecasting the energy demands. The operation of the CHP units is the primary mean for optimising the energy management and by forecasting particularly electricity demand, a better utilization of the biogas storage can be achieved. However, there is also a significant reduction of natural gas consumption and oil consumption is completely avoided in the modelled scenarios. This also indicates that a heat forecast is valuable.

The cost of developing an energy forecasts is at this stage unknown but the estimated savings may indicate the price that can be paid for developing a forecast.

4.4.2. Alternative scenarios

Furthermore, the value of implementing new technology and operating the centrifuges flexible are estimated. The scenarios are analysed both with a fixed electricity price and a market electricity price. The value of implementing the specific technology or operation concept is estimated based on a comparative analysis of costs generated in the modelled scenarios. Table 4 illustrates the fixed price scenarios and

Table 5 illustrates the market price scenarios.

Table 4: Total costs, cost savings, investment cost and simple payback time for the different scenarios analysed with a fixed electricity price.

Scenario (fixed price)	Total energy costs (EUR/year)	Cost savings (EUR/year)	Investment cost (EUR)	Simple payback time (years)
Fixed price	18,478	-	-	-
TEG	46,795	28,317	160,000	5,65
P2G	18,038	440	2,579,750	-
Flexible centrifuges	32,892	14,414	-	-
Heat storage	28,916	10,438	53,300	5.11
Biogas storage	20,217	1,739	680,000	391



Table 5: Total costs, cost savings, investment cost and simple payback time for the different scenarios analysed with a variable electricity price.

Scenario (market price)	Total energy costs (EUR/year)	Cost savings (EUR/year)	Investment cost (EUR)	Simple payback time (years)
Market price	47,190	-	-	-
TEG	75,108	27,917	160,000	5,73
P2G	48,069	879	2,579,750	2936
Flexible centrifuges	59,110	11,919	-	-
Heat storage	59,396	12,206	53,300	4.37
Biogas storage	49,144	1,954	680,000	348

The results in Table 4 and

Table 5 are discussed in the following sections.

TEG scenario

The TEG scenario generates the highest income among the different scenarios. It must be mentioned that it is a best-case scenario, assuming four TEG modules with 354 kW heat capacity each, which is the maximum capacity that can be installed at Braunschweig WWTP.

In general, the value of electricity is higher than heat and the modules uses 7050 MWh heat to produce 246 MWh electricity. Even though the electrical efficiency is low (3.5%), no energy is lost as the remaining energy can be used for heating purposes. With cost savings of approximately 28,000 EUR/year the investment pays back in less than 6 years.

P2G scenario

The P2G plant investment is high and the estimated savings are insignificant in both the fixed price scenario and market price scenario. The analysis shows that the biogas is more valuable for electricity and heat production compared to upgrading, injecting and selling the biomethane as green gas. The P2G units is only operated for 14 hours in a full year in the market price scenario.

Flexible centrifuges scenario

The sludge storage between the digester and the centrifuges generates the flexibility (see Figure 8). The electrical capacity of the centrifuges is approximately 200 kW and their annual consumption composes 3.8% of the total electricity consumption at the plant. In the model, it is assumed that the two centrifuges are operated as on/off



separately as two units of 100 kW each. Otherwise the centrifuges are fully flexible hour by hour, which is assumed to be a best-case scenario.

The scenario analysis shows savings of approximately 12,000-14,000 EUR/year, which indicates that consumption flexibility has a high value. The value is generated because electricity consumption is adjusted to production, causing less costs for electricity purchase. Particularly, in this case where the CHP units are operated only at full load (on/off), it is valuable to have flexible consumption to maximize the use of produced electricity to cover the WWTP demand.

No investment cost is assumed since no new technology is implemented but it requires a change in operation of the centrifuges compared to today. It also requires knowledge of sludge output from digester for the next 48 hours to optimise the sludge storage and thereby the centrifuge operation. Furthermore, it requires electricity demand forecast (same for all scenarios).

Heat storage scenario

At Braunschweig WWTP a significant amount of heat is wasted but by implementing a heat storage with a capacity of 2000 kWh, it is possible to reduce the waste heat by approximately 13% (310 MWh/year) compared to the fixed price scenario. Furthermore, it reduces the natural gas consumption by more than 75% (222 MWh/year).

The total energy cost savings is approximately 10,000-12,000 EUR/year. With a relative low investment cost, the estimated payback time is 4-5 years. No heat loss is assumed in relation to the use of the storage because it is relatively small, which gives many operation cycles in the storage. Heat losses are likely more significant in seasonal heat storages.

Biogas storage scenario

An increased biogas storage capacity (to 8000 Nm³) generates a higher revenue of approximately 2000 EUR/year. The savings are relatively small compared to the investment cost. The larger gas storage increases the flexibility but it cannot be utilised because of the limited production of biogas and the constant biogas outtake from the storage. Only 5% of the time, the storage content is higher than the actual installed capacity of 20,000 Nm³. Therefore, a biogas storage investment does not pay back in this case.

4.5. Sensitivity analysis

A higher carbon extraction from primary and side stream treatment will increase biogas production. A sensitivity analysis is made where it is assumed that onsite biogas production increases by 20%, which is the expected production in Braunschweig in the near future due to upgrades in the sludge treatment line (i.e. thermal hydrolysis). The total energy from all input gas sources is then increased to 41,548 MWh in the analysed period.





Figure 17: Annual energy costs and revenues in the different scenarios with 20% increase of onsite biogas production.

The higher biogas production results in higher electricity sale and lower electricity and natural gas purchase, which generates high revenues compared to the situation in 2015 for all scenarios. In general, the annual revenue is more than 200,000 EUR/year from the increased biogas production. It must be noticed that the increased biogas production is the only input that is changed, but the new sludge line will increase the electricity and heat demand as well. This will reduce the revenues illustrated in the figure.

The potential value of changing from a fixed price scenario to a market price scenario is approximately 24,000 EUR/year, which is less than in the original calculation for 2015 profiles. By comparing the alternative scenarios, the higher biogas production influences the relative value of the different technologies. The TEG modules still generates a higher revenue of approximately 30,000 EUR/year, which is higher than in the original scenario due to more usage time of the CHPs. There are no significant changes in the P2G scenario.

The value of consumption flexibility has decreased by approximately 1/3, because there are less hours with electricity purchase. The value of the heat storage drops to more than half compared to the original scenario. The limited possibility of selling the heat reduces the value of storing heat in a scenario with increased heat production. The value of the biogas storage is still insignificant and it is only 7.5% of the time that the energy content is higher than the original capacity of 20,000 kWh.

5. Conclusion

The purpose of the analysis is to determine the optimal energy management and provide recommendations for highest return on investments for new technology or new operations concepts. A model is developed that simulates the energy management on hourly basis for at Braunschweig WWTP for one full year. Different scenarios are modelled simulating new technologies or intelligent operation concepts at the plant. The total energy cost generated in each scenario is compared to estimate the financial benefits of making alterations at the plant.

The model is based on historical data and the analysed period is from March 10, 2015 to February 27, 2016 (355 days). Historical data from that period is used as input for the model including energy prices, electricity and heat demand and biogas production. Energy can be produced onsite from the four CHP units, gas boiler and oil boilers. Biogas is considered as free of charge and it can be used as fuel for the CHP units and the gas boiler. Electricity is purchased from the grid if it is not possible to produce the entire electricity demand from the CHP units. Natural gas or oil can be purchased to produce additional heat at the boilers. Energy purchase is obviously associated with a cost. Each day in the period is optimised to reduce energy costs while supplying the demand for heat and electricity.

355 optimisations are made, each optimising the operation of the different units and gas storage for the next 48 hours. Using historical data for energy demands and biogas production corresponds to a perfect prognosis, which is a major assumption to the model. It is currently not possible to forecast the electricity demand. However, to optimise the energy management at a WWTP it is considered as a necessity to have electricity demand forecast and biogas production forecast. Otherwise, it is not possible to optimise the use of the biogas storage and thereby energy production of the CHPs

5.1. Recommendations for WWTP operators

The recommendations for WWTP operators are based on the modelled scenarios for Braunschweig WWTP and are obviously case specific. Table 6 sums up the conclusions from each scenario. A comparative analysis of actual costs and the costs generated in the fixed price and market price scenario estimates the value of having an energy prognosis. Comparing the alternative scenarios with the fixed price and market price scenarios estimates the value of implementing new technology at the WWTP.

Table 6: Recommendations based on the different scenarios.

Scenario	Recommendation
Fixed price scenario Market price scenario	These scenarios estimate the value of making energy demand forecasts as they are compared to the actual costs generated in the period. Making forecast of the energy demand, generates a great potential for energy cost savings. In Braunschweig, the savings amount to app. 60,000 EUR/year for the fixed price scenario and 90,000 EUR/year for the market price scenario. Both scenarios are estimated as best-case scenario because perfect prognoses are assumed. The prognoses allow a better utilisation of the biogas storage because biogas can be stored within a period of 48 hours to optimise adjustment of electricity production to



	consumption. The electricity demand forecast is estimated as the most important because electricity is more valuable than heat.
TEG scenario	TEG modules in combination with CHP units are an interesting technology in a case with a high electricity cost as in Braunschweig even though the electrical efficiency is as low as 3.5%. The heat passing through the modules can still be used for heating purposes thereby increasing the electricity yield without wasting energy but only converting energy. The estimated payback time is 5.5-6 years in the Braunschweig case.
P2G scenario	The PtG unit is operated only 14 h/a. In Braunschweig, it is more valuable to use the biogas to produce electricity at the CHPs compared to upgrading the biogas in a P2G unit and selling biomethane to the gas supplier. The case may be different in places with no CHP units installed at the WWTP or other price profiles for electricity and biomethane.
Flexible centrifuges scenario	Flexible consumption is an interesting concept as it allows adjusting electricity consumption to production. Operating the centrifuges flexible generates a higher revenue off 12,000-14,000 EUR/year, which is a theoretical maximum in the Braunschweig case. The flexibility is created from utilising the sludge storage between digester and centrifuges. Forecasting of sludge output from digester and electricity demand are requirements to optimise centrifuges operation. The value of consumption side flexibility reduces when more electricity is produced onsite because of higher biogas production.
Heat storage scenario	A heat accumulation tank is another interesting technology as a significant heat amount is wasted in Braunschweig. By implementing a 2000 kWh heat storage tank in Braunschweig the wasted heat is reduced by 13% but the natural gas consumption is reduced significantly by 77%. The simple payback time is 4.3-5.1 years. The value of the heat storage decreases if biogas production increases because of limited possibility for heat sale.
Gas storage scenario	The purpose of an increased biogas storage is to increase flexibility for CHP operation. Increasing the biogas storage capacity to the double in Braunschweig does not generate significantly higher revenue because of the limited biogas production. This indicates that the capacity of the biogas storage is well sized to the current biogas production in Braunschweig.

The analysis illustrates a great potential for an optimised energy management. The final recommendations are summed up to the following:

- Development of energy prognoses for electricity and heat demand (48h in advance) can optimise the use of biogas storage and thereby energy production at the CHPs
- Heat to power (TEG) increases the overall electricity yield, which is important in a case with high electricity value such as Germany.
- Flexibility on the consumption side makes it possible to adjust electricity production and consumption even better, which is important when the CHP units are inflexible (operated only at full load or “on-off”).



- A heat storage reduces waste of heat and natural gas consumption.

