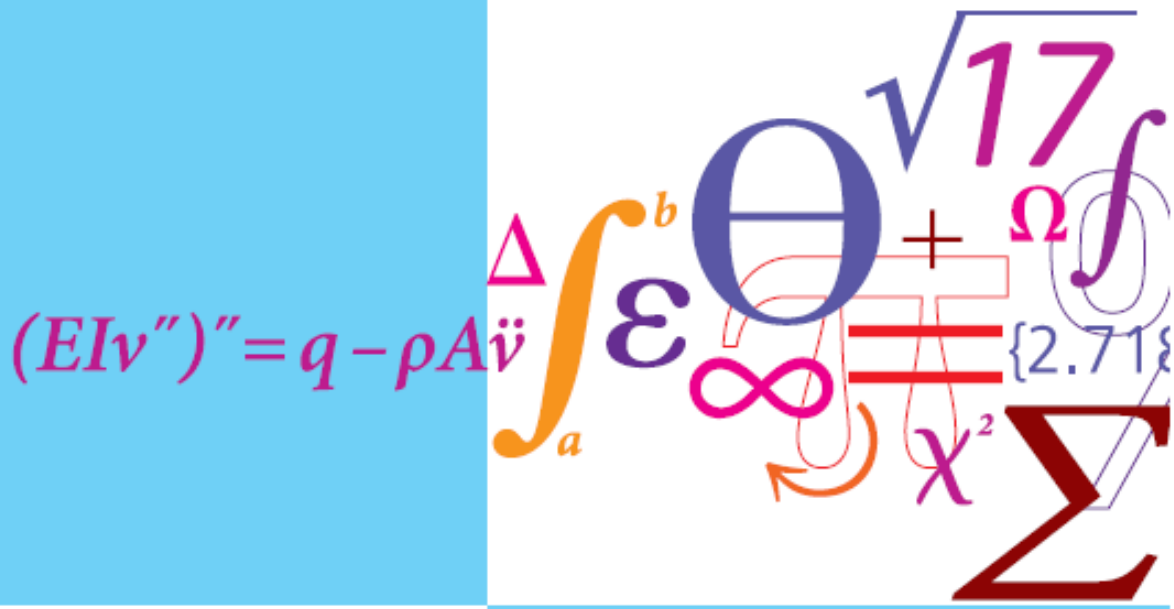
Optimization of Production and Use of Green Gas in the Danish Energy System

Master Thesis



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July 2014

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Abstract

This master thesis investigates how the biomass resources available for biogas production in Denmark, is best utilized in the power and heat sector towards 2035, with focus on the geographical distribution of the biomass and technologies for biogas upgrading.
The thesis presents shortly the theory behind a socio-economic evaluation of an energy project and how it is applied in the project. Two different tools for energy system analysis, STREAM and Balmorel are reviewed based on main functionalities and limitations. Balmorel is chosen as a relevant tool to be used for further scenario analysis based on its ability to optimize investments and operation in the electricity and heat system.
The main contribution of the thesis is the developed mathematical add-on based on linear programming that is integrated with the Balmorel model. The add-on improves the representation of biogas production and use for each district heating area in the Balmorel model. The mathematical framework of the add-on and the biogas production technologies is based on previous model development done by the company Ea. The add-on implements the possibility for investment in amine scrubber and methanation with SOEC technologies for biogas upgrading. The biogas upgrade technologies are chosen based on a review of commercial technologies and developing technologies. The total biomass resources in Denmark are distributed into two fractions; Fraction one has a high content of manure and bound to a geographical area, fraction two has a high content of energy crops and can be used within Denmark.
3 scenarios for the future development in the electricity and heat sector for Denmark are developed for analysis of the add-on. The scenario results show that it feasible for 3% to be upgraded in 2020. In 2035 the feasible share of upgraded biogas is increased to 21-23,5 % depending on the scenario. The upgraded biogas is used on extraction CHP technologies with full load hours below 1000 hours for, all scenarios. Upgrading with a methanator and a SOEC is not feasible towards 2035 and thus the total amount of upgraded biogas was done with the amine scrubber technology. The flexibility of the combined methanator and SOEC technology to provide power regulation and increasing the available amount of biogas is outweighed by their high investment and operational costs.
In comparison with other studies, the scenario results show a lower share of upgraded biogas used by the Danish electricity and heat system. The constraints and limitations of the model tool Balmorel and the add-on are described and discussed in relation to the obtained results.

Preface

This thesis has been carried out at the DTU institute Management Engineering in the System Analysis division on Risø, in collaboration with the company Ea Energianalyse. The thesis constitutes 30 ECTS credits and is a part of the requirements to obtain the Master of Science in Engineering in Sustainable Energy (MSc Eng), from DTU. The thesis was carried out in the period 10. February 2014 to 10. July 2014.

I would like to give acknowledgement to the people who have a part in the final product. The first two mentioned are the supervisors of the project.

Marie Münster, DTU Management Engineering
For supervision and guidance in all phases of the project, and helping with structuring the process of carrying out the thesis. You always made the long way to Risø campus worthwhile.

Anders Kofoed-Wiuff, Ea Energianalyse
For supervision and valuable guidance during the project.

Lena Kitzing, DTU Management Engineering
For reading and providing valuable critique on the report.

Hans Ravn, DTU Management Engineering
For guidance with Balmorel and matematical modelling.

Karsten Hedegaard, Ea Energianalyses
For giving me the first introduction to Balmorel, and for always having time for helping with Balmorel.

I would also like to thanks the rest of Ea Energianalyse for providing a pleasant and inspiring work environment to carry out the thesis.

Morten Sander, s082569
DTU, 10. July 2014

Contents

List of Notations

Nm^3 Normal Cubic Meter the amount of Biogas, upgraded biogas or gas, which at a temperature of 0 degrees Celsius and an absolute pressure of 1,013 bar, without water vapour, and a volume of one (1) cubic meter.

AD Anaerobic digester

CHP Combined Heat and Power

DEA Danish Energy Agency

DH District Heating

DK_CA Central DH area

DK_E_SA Small technology specific DH area in Eastern Denmark

DK_MA Medium DH area with waste

DK_MAM Small DH area with waste

DK_W Western Denmark electricity region

DK_W_SA Small technology specific DH area in Western Denmark

EC Biomass consisting of Energy crops and grasses

EUDP Energiteknologisk udvikling og demonstration

Endogenous An expression used in economic modelling: Something that comes from outside the model, e.g investments in wind capacity based a solver optimization routine

Energy Crops Energy crops are crops where the harvest yield is mainly used for energy production. By this definition straw and corn stover are not covered by the term.

Exogenous An expression used in economic modelling: Something that comes from outside the model, e.g user specified investments in wind capacity

MAN Biomass consisting of manure and organic waste fractions

O&M Operation and Maintenance

PEM Polymer Electrolyte Membrane

PSA Pressure swing adsorption

SOEC Solid Oxide Electrolysis Cell

TOFC Topsøe Fuel Cells

TS Total Solids - Total Dry matter

VS Volatile Solids - Organic dry matter

WI Wobbe Index: The WI is used to determine the interchangeability of fuel gasses and is necessary because different mix of gasses can have different combustion properties when used in a gas appliance. It is measured by the energy content per standard cubic foot by the square root of its specific gravity with respect to air. The value also has a meaning in terms of combustion quality as too high Wobbe index can imply formation of hydrocarbons

aMDEA activated Methyldiethanolamine

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Introduction

1.1 Setting the Frame for the project

Current development in Danish energy policies

With the energy agreement in Denmark from 2012 a majority of political parties set the scene until 2020. In the agreement focus was directed at an increase in Danish biogas production, and a new framework was implemented to incentivize development in the sector. With the new framework it is expected that up to 50 % of manure from Danish farm animals should be used for energy purposes in 2020 [1], primarily for biogas production, as this has been concluded to be the most efficient energy conversion of the manure fraction [2]. Furthermore, the allowed fraction of energy crops for biogas production is being reduced in the years to come [3]. In the context of the new framework it is interesting to analyse the optimal use of the available biomass fractions for biogas and the further utilization of it in the energy system in a long term socio economic perspective. The analysis can form the backbone of evaluating the current framework up to 2020 and how a subsidy and tax system that ensures private economy investments in an optimal portfolio of technologies, looking beyond 2020, could be constructed. The national goals set towards 2050 where total independence of fossil fuels is envisioned, are coal free energy sector in 2030 and a 100 % renewable electricity and heat sector in 2035.

The analysis should take into account that the socio economic gain of technologies to be implemented depends on their economic and technical characteristics and their interaction with the incumbent technologies and technologies which are already planned to be implemented from political side. In the future Danish energy system the ability of technologies to provide flexibility for integrating a high amount of wind power is an important aspect for evaluating the gain.

The determining factors for the optimal use of biogas are the biogas production profile and amount of produced biogas in conjunction with the consumption profile for potential users. Today the majority of the produced biogas is utilized at de-central combined heat and power (CHP) plants. The production profile of the CHP plants and their consumption of biogas depends on the heating demand of local households in the associated district heating system. The demand pattern varies throughout the seasons with a peak in the winter months and a low in the summer months. With the planned expansion of the biogas production the

local need for biogas can thus exceed the biogas production that can be allocated unless it is upgraded an injected into the natural gas system or used for transportation.

Biogas production overview Denmark

The biogas in Denmark is mainly produced at central biogas plants, farm plants and waste water treatment plants as seen in table 1.1. The investments in new central biogas plants have been limited the last decade, and in the period of 1998-2011 no central biogas plants was invested in. In a report from the Danish Energy Agency (DEA) [4] the estimated level of produced biogas was in 2012 4,4 PJ. This amounts to approximately 0.55 % of the gross Danish energy consumption according to numbers from DEA [5].

Table 1.1: Biogas production in Denmark 2012

Unit:	(TJ)	%
Sewage sludge Biogas plants	898	20.5
Industrial Biogas plants	184	4
Landfill Biogas plants	203	5
Central Biogas plant (manure)	2123	48.5
Farm biogas plant (manure)	973	22
Sum	**4383**	

In 2020 AgroTech has estimated the biogas potential to 40-60 PJ [1]. Manure has the potential to contribute with 21 PJ biogas, or 520 mio Nm^3 methane per year which amounts to 2/3 of the total collected manure. The potential is calculated from the amount of total solids available. The second largest biomass resource is straw, followed by organic municipal waste and various grasses [1]. The strategic goal of utilizing a large amount of manure for biogas is the cost-efficient green house gas emission reductions from de-gasifying it. Manure stored in anaerobic conditions such as manure tanks converts some of the carbon content to methane which is emitted into the atmosphere. It was shown in [6] that the green house gas reduction in storage emissions from de-gasifying the manure yields an abatement of the same size as the CO_2 reduction from substituting natural gas with biogas. In addition the nitrous oxide (NO_x) emissions from transport of fertilizer to the fields are considerably reduced. Energy conversion of manure compared to other biomass is therefore a tool for cost-effective greenhouse-gas reductions.

Production of biogas with manure yields a low energy output because of a low content of volatile solids (VS). The yield is increased by co-digesting manure with other biomass to reach a profitable energy content. The biomass for co-digestion are mainly industrial organic waste (slaughter houses, fish industry and more) measured by energy output. At the moment the industrial waste account for around 50-60 % of the biogas energy produced in Denmark. The Danish potential from this resource is however almost exhausted and a part of the organic waste is imported from other countries in Europe. The use of energy crops is also widely used as co-digestion substrate. However it has been shown that the use of energy crops is not sustainable [3]. Thus the use of energy crops are restricted to 25% in 2013 and 12% in 2021 as measured by weight going into a biogas production plant [3] for receiving subsidies.

Currently the manure from Danish farms is utilized at a percentage of 5-8 % [7]. With the new framework subsidies around 30 new biogas plants are being planned at the moment of writing, and at least 10 large and 9 small plants have obtained plant investment subsidies.

According to [8] the political goal of 50 % use of manure for biogas can be achieved with around 50 new biogas plants that has an input of 1000 tons per day with manure as main biomass input. In light of this there is still need for a large number of new investments in the sector if the political goals shall be fulfilled by 2020.

Production and use of Biogas

The biogas production profile from central plants where manure is largest biomass fraction has flat production profile due to the steady production of manure. The possibility to produce biogas from biomass fractions that can be stored throughout the year, such as energy crops, facilitates a production profile that can be seasonally regulated. This has been examined in a report from PlanEnergi [9]. Regulating the biogas production to fit the demand profile for house hold or industrial heat demand can potentially raise the value of the biogas for the energy system as it is used more flexible. Another flexible option for the biogas is to invest in facilities to upgrade the gas to a combustion quality such that it can be injected into the natural gas grid. The injection makes it possible to sell the gas both regionally and internationally on the gas market and can be used flexible by means of the already existing storage capacity. Upgrading the gas can be advantageous in parallel with regulating some of the biogas production seasonally. Two types of technologies are interesting regarding upgrading biogas, either upgrading by removal of CO_2 from the biogas or technologies that methanate the CO_2 with use of hydrogen gas. Besides the potential value of upgrading the biogas as a renewable fuel, the technologies can contribute with an additional value to the energy system: The upgrading the production of hydrogen gas with electrolysis and the electricity use for the CO_2 removal facilities can provide up-regulation (from a demand side perspective) to the power system. Since the methanation process is exothermic, the produced heat can further more be utilized in the DH system. The benefits of the flexibility to the system should be counter balanced with the costs of investment and operation of the technologies for assessing the benefits to society. Upgrading by methanation is per delivered energy from the plant, a more expensive technology than upgrading by removal of CO_2. However it can increase the available energy of gasses with a carbon base, as the carbon atoms of the CO_2 molecules in the biogas is utilized. The extra available energy of gasses with a carbon base can prove to have a value in an energy system where the fossil fuels are restricted, the biomass resources are used to their full potential and assuming that no breakthrough in handling hydrogen gas in the electricity and heat sector have evolved.

1.2 Previous Studies

This section presents an overview of the existing research done in the fields related to this thesis. The main focus is on literature regarding modelling and optimization of production and use of biogas in small scale system analyses, and in national energy system analyses with focus on integrating wind power and biogas. Relevant papers and articles from the last 5 years have been included.
National energy system analysis with focus on integrating a large share of wind power in the Danish power system have be en dealt with in a number of studies with attention given to different areas such as increased flexibility in the system by integration of heatpumps in [10], electrical vehicles [11],[12], expansion of the district heating network [13] waste to energy technologies [14] and storage technologies [15]. Other studies have dealt with demand side response [16] that integrates consumer flexibility in response to short term variations in the electricity market.In a report from EA [17], the large scale integration of biogas and its effect

on the energy system is evaluated by analysing the optimal use of biogas in Denmark for selected years towards 2050 from both a socio economic and private economic perspective in scenarios with high penetration of wind power. The analysis shows that direct use of biogas in CHP plants is socio economically feasible towards 2035, under certain assumptions for example that 50 % of the potential is available for the power and heat sector. From 2035 the phase out of natural gas in Denmark increase the level of biogas being upgrading. In the analysis, the estimated cost of producing, storing, and delivering both biogas and upgraded biogas as fuel is lumped into a single parameter, which means that the model does not perform optimization of the biogas production, storage and upgrading technologies individually. In this way the possible flexibility to the system provided by upgrading technologies or the system benefits of seasonal regulated biogas production are not accounted for. Additionally, the geographical distribution of biomass fractions such as the manure fraction is not included in the model.

Modelling biogas production and its further use have been considered in a number of reports. In [18], [19], [20] and [21] socio economic evaluation of biogas technologies and the total value chain have been performed. In general, the socio economic studies studies focus on biomass composition and transportation of biomass and regulation of the biogas production facility, and including a high number of externalities in the whole biogas production chain. The interaction with the surrounding energy system is typically limited to a single consumer technology e.g a gas motor which can sell it's power and heat to a predetermined price. These analyses do therefore not take the effects of the dynamics between the biogas production and upgrading technologies and the energy system, into account.
In [22] from Ea, modelling focus is put on the dynamic interaction between biogas production technologies and a system comprised of technologies that can potentially use the biogas. The produced biogas can be distributed to the industry for process heat, to upgrading and injection in the natural gas grid with a water scrubber facility or to CHP and boiler technologies to produce power and heat. The optimal size of system components and the system operation is decided by an optimization tool for both a socio-economic and private economic perspectives. Two kinds of biogas production units are modelled, which utilize different biomass fractions: A seasonal and a non-seasonal. The biogas plant that use the seasonal biomass fraction can regulate and adapt the production of biogas to a varying system heat demand. Different case scenarios are designed to evaluate the flexibility of the biogas production units in the heating area and the optimal use of the biogas in year 2020. Other studies such as [23] have also analysed the optimal use of biogas. However seasonal regulation of biogas production is not represented and the analysis is done on the energy system anno 2008.

1.3 Thesis Statement

In the previous studies that have been carried out, as described in section 1.2, it was observed that the representation of biogas production and use in national energy system analyses that has been used to date is too simplified to adequately capture the possible system benefits of upgrading biogas and seasonal regulation of biogas production. Furthermore it was observed that the studies that have been focusing on detailed modelling of biogas technologies and their value chain share an inability to evaluate the impact of large scale penetration of biogas technologies on the energy system. This leaves a gap in the studies where a better representation of green gas technologies, including seasonal regulation of

biogas production, and the geographical distribution of the biogas potentials in a national energy system analysis, can help conduct a more accurate evaluation of their system benefits of how to best utilize biogas, either directly or as upgraded to natural gas (NG) quality. The evaluation should take into account possible future energy scenarios and can thereby be used as a tool for decision makers to structure appropriate subsidy and tax schemes.
With the identified gap in the current research, the aim of this thesis is to implement a mathematical add-on with a more detailed representation of green gas technologies to an already existing national energy system model. The possibility of upgrading biogas with a combination of methanation with hydrogen provided by a SOEC is included, which can increase the available fuel from biogas. With the add-on implemented, relevant scenario analysis of the production and use of green gasses in the Danish electricity and heat system is carried out. The analysis is guided by the questions:

- Which investments in Green gas technologies will be beneficial towards 2035 from a socio economic perspective?
  - To which extent is it feasible to upgrade biogas to natural gas quality, in preference to using it locally?
  - Will upgrading with methanation with hydrogen provided by SOEC's be feasible in a future energy system with limited biomass availability?

To answer these questions a generic Green gas add-on that represents biogas production and its further use in the electricity and heat sector, is implemented in a mathematical model of the electricity and heat system, developed by Ea in [17] with the Balmorel modelling tool. The mathematical framework of the add-on originates from the biogas model developed by Ea in [22]. The new add-on is developed such that it can be applied to any number of the district heating areas represented in Denmark, in the energy system model from Ea.

1.4 Guide for reading the thesis

Comments

In the thesis title the term "green gas" is used as a broad term for gasses that is produced from biomass with various processes, as described in 4.

Report Structure

A short introduction to the chapters of the report are given in the following.

Chapter 3: Socio-economic Evaluation of an Energy project This chapter explains the methodology for conducting a socio economic evaluation of an energy project and how it is used in relation to this project.

Chapter 4: Energy System Tool The first section of this chapter introduces 2 different energy system tools and discuss their applicability in relation to conducting analyses that can answer the thesis research questions. The second section describes the chosen tool.

Chapter 5: Biogas Production and Upgrade Technologies The technologies biogas production and different upgrade technologies are presented, and relevant technologies are selected for use in the developed add-on.

Chapter 6: Developed Model Add-on: Mathematical Description The mathematical description of the developed add-on is described in this chapter. This includes the differences from the biogas model developed by Ea [22] and the editing of the electricity and heat model with the Balmorel tool by Ea in [17].

Chapter 7: Verification of the Developed Model Add-on The developed add-on is verified by comparing the add-on implemented in 1 DH area to the results from case scenarios from Ea with the biogas model in [22]. Furthermore the operational pattern of the methanator and SOEC is verified.

Chapter 8: Scenario Analysis using the developed Add-on The developed scenarios used for subsequent analysis with the add-on are described in this chapter. Furthermore, some of the underlying model constraints in the model developed by Ea in [22] are verified.

Chapter 9: Results The chapter contains the results of the scenario analysis.

Chapter 10: Discussion & Future Work This chapter discuss the results from the scenario analysis and the general validity of the model, and relates this to future work.

Chapter 11: Conclusion This chapter wraps up the work of the thesis.

2

Socio-economic Evaluation of an Energy Project

This section introduces the method of socio economic evaluation and describes how it is applied in the further analysis in the project.

Methodology

Evaluating a project in a socio economic framework, the outcome of the evaluation is typically measured as the internal rate of return (IRR) or the net present value (NPV) of the project to the society. The IRR is the expected annual effective rate of return of a project or an investment, a relative term. The NPV is measured in monetary terms and is an expression of the changed opportunity for monetary consumption for the citizens. In the energy system analysis carried out in this thesis the model tool Balmorel is used to find the optimal solution for technology investments decisions and operation of the technologies, for different scenarios when implementing Green Gas technologies in the modelled energy system. Balmorel solves to the optimum that maximizes the NPV value of the represented energy system [24] under the given constraints. When deciding for rejecting or accepting a single investment based on profitability the NPV and IRR the two methods will always lead to the same conclusion [25]. However when dealing with deciding investments of a portfolio of investments where the IRR and NPV method will not always rank investments in the same way. In accordance with [25],the NPV method should be used for the highest profitability. The evaluation of the socio economy of a project consists of assessing the gains or losses to the society in cash flows for the duration of the project and discounting the flows to present day value. The NPV can be calculated from equation 2.1. F_t is the total cash flow in year t comprised of benefits and costs and r is the discount level. T is the technical lifetime of the technology. The discount rate is the social discount rate which represents the opportunity cost, that should reflect the value of the best alternative use of the money. In this project the social discount rate used is 4% and is a reference value from the Danish ministry of Finance [26] to be used when performing socio economic analysis in Denmark. The NPV is in this projects calculated in relation to year 1990 in Euro currency, EURO90. The EURO90 currency is used a standard in the Balmorel model and thus all existing input

to the model is deflated to that currency level. The additional input prices and costs used to find the discounted cash flows each year are therefore expressed at the EURO90 price level. A project is profiting the society if the sum of the discounted cash flows are positive, yielding a positive NPV.

$$NPV = \sum_{i=0}^{T} \frac{F_t}{(1+r)^t} \tag{2.1}$$

To asses the outcome of a socio economic analysis the boundaries of the system analysed and the assumptions of the inputs to the system, including the externalities must be defined. The boundaries and assumptions set the frame for comparing the socio economy outcome of comparable projects. Externalities whose economic benefit or cost to the society which is not captured or only partially captured by the market should have assigned an economic value. Some externalities can be hard to quantify and can be subject to uncertainty. The boundaries and socio economic assumptions are discussed in the following sections.

Boundaries

Geographically the model encompass a large part of the energy system of both Denmark and the surrounding countries with electricity exchange between countries. The model-runs optimization estimates how the spot price for both electricity and heat at regional and area level is affected by substituting production of energy with different technologies. The simulation of the energy markets sets a solid framework for analysing how different portfolios of technologies implemented both in small and large scale interact in the energy system and to asses the socio economic impact. This feature makes it different from many other types of analyses where yearly average energy prices are used and estimations of the marginal technologies are used for determine substituted emissions.

Socio Economic Assumptions

The framework for making a socio economic evaluation of a project follows the guidelines in [27]. The costs included in the NPV are system supplies, investment costs, operational costs both variable and fixed, fuel costs, emission costs, loss of energy in transmission and distribution grids. Some elements from the guideline are not included in the assessment such as net Taxation factor and tax distortion. This is discussed later in this section 2.

Investments Costs, Operational Costs and Technical Characteristics Data regarding economical costs and technical characteristics for existing technologies in the Balmorel model has been collected and updated continuously through the projects that has developed the model to the current version. The costs of technologies introduced in this project for biogas plants, storage facilities, upgrading facilities are based on values from both commercial technologies, from full scale demonstration plants and pilot plants in operation. Not included in the cost of technologies are decommissioning costs and scrap values. These cost and values can vary from technology to technology. Also not included is system integration costs related to additional equipment for power angle correction, voltage stability and frequency regulation for managing stability and control in the power system. Efficiencies for technologies are stated as LHV efficiencies and LHV values are used for stating energy content of fuels and fuel flows.

Fuel Price The fuel prices are based on the World Energy Outlook forecasts about the future fuel price developments. Prices are subject to great uncertainties both long term and short term as they depend on numerous factors that are subject to change. Uncertainties are typically related to changes in demand and supply from unforeseen changes in the political climate affecting the fuel market or new resource discoveries and/or technological advancement in extraction methods. In recent time these uncertainties have shown their impact on fuel prices. The first example is the recent shale gas findings in the US and the following large extraction and use of the gas. The large quantity of the resource has shifted the coal price downwards in Europe due to cheap coal now redundant in the American market, being shipped to Europe. The effect on the European coal price was a drop around 34 percent from March 2011 to February 2013 [28]. An example of how politics can have an influence on prices has been observed in Europe where both the price and supply of natural gas have been used as means to assert geopolitical pressure on other countries. In 2006 and 2009 the Ukrainians had their natural gas supply cut off by the Russians. The incidents affected 18 other countries in Europe because the gas pipe was upstream of the other countries supply [29]. These kind of uncertainties are hard to capture in the predictions made by the World Energy Outlooks. The predictions however form the most reliable data source available but the uncertainties related to fuel prices are taken into account in the sensitivity analysis.

Prices, Net Tax Factor and Tax Distortion The electricity prices and heat prices in each time period are found endogenously in Balmorel as the marginal long term costs of producing an extra MWh of electricity and heat,respectively, and can as such to some degree be interpreted as reflecting the market spot price.
The prices used as input in this project are factor prices meaning that they are excluded from fees and taxes. A projects that shows a positive socio economic change is benefiting the society because of the increased willingness to pay for it's citizens [27]. The consequences of the project should therefore be weighed with the prices that reflects the preferences of the citizens [27]. The weighing factor is called the Net taxation factor, NTF. The NTF is calculated as the ratio of the gross domestic product and gross factor income and therefore reflects the average level of taxation from producer level to consumer level for goods and values accounted for in factor prices [27]. As such factor prices multiplied with NTF represents how an alternative use of the resources spent is valued at consumer level. According to [27] a factor of 1.17 should be multiplied to all costs calculated as factor costs to express the socio economic valuation of the project in Denmark.
When a public initiative undertakes a project the operational costs can be higher than the revenue, and the project can still have a positive socio economic impact because of abated emissions or other benefits for the society. The income deficit in a public project is financed by an increased taxation of other activities in the society [26]. Tax distortion is referring to the cost incurred by rearranging the costs by the taxation system to pay for the income deficit. Depending on how the taxation is carried out the effect can have different economic consequences [30]. A classic example is taxation of labour, which incurs both an income effect and a substitution effect which ultimately results in a lower amount of labour and thus inducing a cost for the society. In Denmark the assumed marginal cost of using distorting taxes is 0.20 DKK for every 1 DKK charged in taxes.
Including NTF and tax distortion is relevant when evaluating a project for seeking approval for grants and subsidies based on the socio economic benefit. As this project does not aim to give an exact socio economic valuation, but to analyse the relative consequences of interaction between technologies operating within political constraints in the energy system, there is no need to use the factors as it would result in multiplying costs with scalars which

would not change the outcome of the optimization in Balmorel and thus affect the subsequent analyses.

Externalities

Externalities Included The externalities included in this project is downstream emissions from energy technologies which are the typical externalities included in energy system analyses.
Emissions
Energy production and use leads to emission of gasses and particles. In this analysis the emissions from energy use and production of electricity and heat are taken into account in the evaluation. The emissions stem from the energy conversion of fuels to energy, and the emissions from operating the production technologies. The emission that are accounted for are CO_2, SO_2 and N_2O for fuels and CH_4, NO_x and SO_2 for energy generation technologies. The energy conversion for the fuels biogas and upgraded biogas does not register as CO_2 emitting in the emission balance as fuel derived from biomass is considered CO_2 neutral from a political standpoint. The rationale is that all biomass is considered CO_2 because of the carbon uptake of the biomass during photosynthesis. Additionally if the biogas is not substituting green house gas emitting fuels the carbon content of the biomass used to biogas production would have been emitted on the field when used as fertilizer in the state of manure.
Green house gas emission costs are priced to reflect the CO_2 quota marked price projection made by the World Energy Outlook(2012). The projected price development of the CO_2 quotas can be seen in appendix A3 in figure A.6. The prices until 2020 have been adjusted in accordance with a report from Ea [22], to a lower value that reflects the current low expectations to the CO_2 quota marked. The emissions equivalents of methane and N_2O equivalent can be observed in table 2.1.

Table 2.1: CO_2 emission equivalents, from [31]

CO_2	1
CH_4	25.0
N_2O	298.0

Not Included Externalities Some externalities can only be stated with great uncertainties and other can be hard to assign an economic value [27]. This section lists some of the externalities not included in the analysis. The list is not exhaustive.
General externalities not included:

- Upstream effects such as pollution and social effects on mining activities for procuring fuel
- Downstream effects from energy production such as social externalities related to noise and odour.
- Job creation effects from investments. These effects both long term and short term are difficult to estimate as job creation can have different effects on local and country economy scale.

- Effect of security of energy supply. The security of supply is highly prioritized from a political point of view, in order to minimize the effect of changes in fuel prices and political climate in other countries [32]. The monetary effect is however very hard to establish.

Externalities not included regarding biogas production:

- Externalities related to odours from the biogas production facilities are not included. The smell nuisance can have a large local impact on communities according to [33].
- The use of de gassed biomass as fertilizer on the fields represent a change in emission factors for the biomass. The fertilizer effects are:
  - Change in composition of the biomass can influence the fertilizing value of the the gasified biomass, and thereby change the demand for synthetic fertilizer. When using a biomass with high waste to manure ratio the need for synthetic fertilizer is reduced [7]. Another reduction in used synthetic fertilizer is due to a higher nitrogen efficiency from gasified biomass [19]. This reduced use of synthetic fertilizer also induce reduction of N_2O emissions.
  - When the gasified biomass is used as fertilizer on the soil, a part of the carbon content is sequestrated in the soil layer and the rest is emitted as GHG from digesting in the top layers of the soil. The gasification reduce the carbon content and thus the GHG emission on the field.
  - Gasified biomass is simpler to handle and easier to dispense on the field [7].
  - Leaching of nitrogen and phosphor is reduced in the local environment as a consequence of higher efficiency.
- Consequences from land use change and indirect land use change. Using energy crops for producing biogas increase the demand for farming areas which will change areas with high carbon sequestration or/and biodiversity into farming areas. In a report by the Danish Energy Agency it is pointed out that the effects of Land use change, LUC and indirect land use change, ILUC, can be considerable but that there is uncertainties about the actual order of magnitude. The DEA have set limits for the future use of energy crops to counteract the effects from LUC and ILUC [3]

3

Energy System Tool

This chapter is related to the tools used for energy system analysis. The first part of the chapter reviews two relevant energy system tools and compares their functionalities and characteristics. Based on the type of analysis that is carried out in this project the most suitable tool is chosen. The second part of the chapter describes the chosen tool on a more detailed level.

3.1 Review of Energy System Tools

To make a technical analysis of how Green Gas technologies can be implemented in the energy system an adequate modelling tool that can represent the energy system is needed. In this section a comparison of two energy tools that are regularly used in connection with analyses of implementation of technologies in the Danish energy system is made. The two tools STREAM and Balmorel have different characteristics that make them suitable for different kinds of energy system analyses. The comparison identifies the functionalities that are suitable to perform an adequate system analysis related to the goal of the thesis.
The classification of tool types can be seen in table 3.1 along with the covered energy sectors and the type of analysis typically conducted with the tools regarding time frame for scenarios and time resolution of the modelled system. The table have been created with inspiration from [34].

STREAM

STREAM is a simulation model build on a spreadsheet platform and can be used as a scenario building tool for quick overviews of green house gas (GHG) emissions, energy resources, fuel consumption and to find the demand for energy in a chosen year as seen in [34] in an energy system of a country. The STREAM model covers all energy sectors. However the representation of electricity transmission between neighbouring countries is limited [35] such that the analysed country can be allowed to export an exogenously chosen amount of power. The demand for energy is assumed to grow equivalently to the economic growth and different energy intensities for the energy sectors. The model can simulate the hourly balance of production and demand with it's load duration curve model where historical time

series for demand are used. However the operation of dispatchable plants is not optimized but is selected manually by prioritising the plants. Using load duration curves implies that time chronology is lost when balancing the demand and supply. As such the value of technologies that contributes to the system with flexibility is not fully appreciated [14]. The run time of the model is very fast, only a few seconds, which makes it suitable for meetings and workshops where it can be useful to get an overview of how energy flows are affected by changes in demand and supply or changes in relation to how the system is balanced.

Balmorel

Balmorel is an optimization model of operation and investment decisions. The model can simulate the electricity sector and the district heating sector in Denmark, Sweden, Norway, Finland and Germany and the interconnections between. It is a partial equilibrium model which means that it establishes an equilibrium between demand and production in part of the economic system, here the energy system. The transport sector is not included, however in some versions developed in [10],[11] and [12] plug-in electric vehicles have been implemented for analyses of flexibility measures in a power system with large penetration of wind power. The highest time resolution is hourly and the time frame is up to 50 years. The Balmorel tool is used for modelling and analysis in this thesis. The optimization of both operation and investment of energy production units makes it possible to evaluate the economic competitiveness of a portfolio of technologies in order to ensure system balance and achieve political targets. In relation to this project the feature makes it possible to evaluate value of the flexibility of the green gas technologies to the system. This is one of the major reasons for choosing Balmorel. Another important reason for choosing Balmorel is it's transparency (sic) through full code documentation in the working files and that all code can be modified by the user. An introduction to Balmorel and its main functionalities is given in the following section.

Table 3.1: Energy tool type characteristics

Tool	Type						
	Simulation	Scenario	Equilibrium	Top-Down	Bottom Up	Operation Optimization	Investment Optimization
Balmorel	Yes	Yes	Partial	-	Yes	Yes	Yes
STREAM	Yes	-	-	Partly	Yes	-	-
	Energy Sectors						
	Eletricity	Heat	Transport				
Balmorel	Yes	Partly	-				
STREAM	Yes	Yes	Yes				
	Geographical area	Scenario time frame	Time-steps				
Balmorel	International	50 Years Max	Hourly				
STREAM	National/regional	1 Year	Hourly				

3.2 The Balmorel model

The Balmorel model was originally developed in a project by the Danish Energy Agency and the former TSO Elkraft System [10]. The model is used for energy system analysis by companies and institutions such as EA Energi Analyse, RAM-løse, the Technical University of Denmark, the Danish Energy Association among others. The core model structure has been used to develop other energy system models in other regions of the world. The code is written in GAMS (General Algebraic Modeling System) language which is designed for mathematical optimization problems. In this project a linear version of Balmorel is used which means that start up and unit commitment of technologies is not represented. The model optimizes operation and annualized investments within a year to the least cost solution which can also be interpreted as maximizing the social surplus. This does not fully represent a real world situation as investments will include analysis of future fuel and technology costs [14]. It is assumed that perfect market competition takes place such that all market agents behave rationally and that they have full information and no market power is exerted [36]. In the Danish power system the uncertainties of wind production and risks related to outages of power system components are mitigated through a set of markets that operates on different time-scales to ensure stability in the power system by matching demand and supply of power. The main markets of traded power is the Elspot and Elbas markets. Elspot is a day ahead market where actors place bids with production amounts in a time window of 12 to 36 hours before the actual operation hour. The Elbas market is working after closure of the Elspot market. Until an hour before the operational hour, Elbas market actors can trade with quantities that deviate from the expected trade plan from the Elbas market. In addition to the day ahead and the intra-day market two intra-hour markets,the reserve and regulating market exist. In the regulating market the power producers are paid to have a standby capacity available, which the transmission system operator, TSO, can activate when needed with a response time of 15 minutes. The reserve market, power producers make system services such as frequency control and other ancillary services such as voltage control and reactive power reserves[37]. As mentioned the optimization routine in the Balmorel model assumes perfect foresight in wind production, outages and load demands [36]. As a starting point the model therefore underestimates system costs [14]. To handle the underestimation the model ensures that excess capacity is available at al times. The reserve market services is to some degree represented by ensuring that sufficient base load production on facilities that deliver frequency control and other ancillary services are operated. The two constraints are ad-hoc solutions that to some degree justify not representing the reserve and regulating markets in the model. However the costs of integrating high amounts of technologies that require power system services, may not be captured by the model.

Input

The optimal least cost solution is subject to the accuracy of the input parameters. The input to the model can be seen in figure 3.1 and includes technology characteristics and scenario data such as the demand and resource limitations. The base demands are specified as annual nominal demands either for an area or a region. To take into account the consumer utility of demand for electricity and heat and the prices a price elasticity function can be implemented [38].

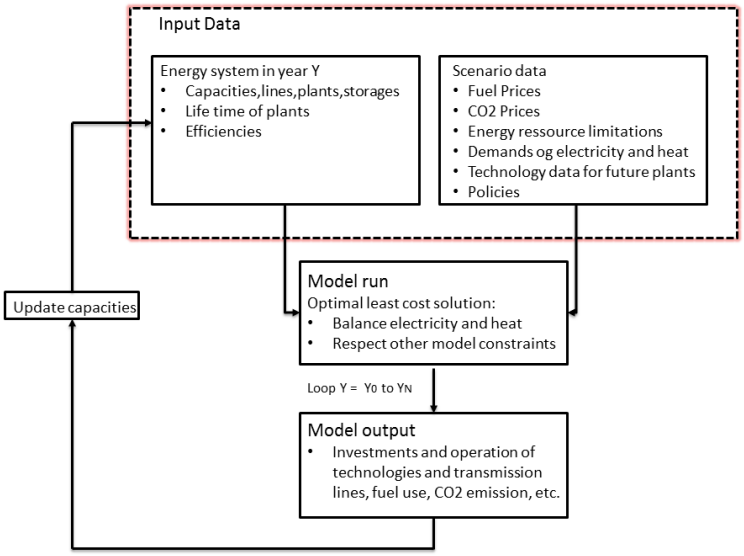

Figure 3.1: Sketch of Balmorel Input

Geography

The geography is represented by three entities: Countries, regions and areas. The model comprises 5 countries, Denmark, Germany, Norway, Sweden and Finland. Countries consist of regions that are linked by power transmission lines, and regions consist of district heating areas. In the version of Balmorel used, Denmark is represented by 48 district heating areas and two electricity regions. The electricity regions in the model can be seen in figure 5.1. For different analyses excluding one or more countries is possible.

Technologies

The technologies represented in the model include condensing units, Extraction-CHP, Backpressure-CHP, multiple renewable technologies including wind power, solar power and heat, hydro units, heat boilers, heat pumps and different energy storages among others. Selected technologies can use more than one type of fuel, and selected technologies can be refurbished to accommodate a new fuel type.

Time

Each year of optimization is represented with a user specified number of seasons and time periods within the season. The most detailed time resolution is 52 seasons and 168 time periods within each season for one year which more or less gives the user the possibility to run optimizations on an hourly basis. When selecting fewer seasons and time periods for the optimization routine, the model accumulates demand profiles time periods and scales them appropriately to maintain the variability in balancing the demand with production. The size of the problem and the resulting time use for solving it greatly depends on the number of represented time periods and seasons. Variability is inescapably lost when decreasing

representation of seasons and time periods, thus it must be ensured that sufficient resolution is applied to be able to evaluate the flexibility of the technologies in question.

3.3 Mathematical framework

This section introduce the most important mathematical framework of the Balmorel model consisting of the main equations. The equations displayed are expressed in a simplified syntax compared to the GAMS code, by using shorter names for sets, parameters and variables, not distinguishing between names of different subsets and not including all parameters such as the time weighing parameter. The syntax used in the report is listed in the following array, and translated into the syntax used in the GAMS code in appendix C.1. For describing a relationship of a two dimensional data item in a statement that address the same elements in a set, e.g the transmission lines between two regions, a subset r and a subset ir referring to r is defined.

Sets and indices

$a, \mathbb{A}$	Relevant subset of Areas, set of Areas
e	Emissions types, e.g. CO_2
f	Fuel types
$g, \mathbb{G}$	Relevant subset of generation technologies, set of generation technologies
$t, \mathbb{T}$	Relevant subset of time steps, set of time steps
$r, ir, \mathbb{R}$	Relevant subset of regions, subset of regions referring to r, set of regions
$el.$	Electricity
h	Heat
imp	Import from neighbouring regions or area
exp	Export from neighbouring regions or area

Parameters

C	Cost [Money/MWh]
C^{inv}	Investment cost [Money/MW]
C^{fix}	Fixed operation and maintenance cost [Money/MW]
C^{var}	Variable operation and maintenance cost [Money/MWh]
C^{ext}	Cost of externalities associated with emissions [Money/kg]
DE	Demand of electricity [MWh]
DH	Demand of heat [MWh]
R	Availability parameter
K	Existing capacity of technology [MW]
W	Emission factor [kg/MWh]
η	Fuel efficiency of generation technology
η^{loss}	Transmission efficiency
$KX^{\max}$	Maximum transmission capacity [MW]

A_f	Annual resource cap of fuel f [MW]
Variables	
VG	Generation on technologies [MW]
VX	Transmission of electricity [MW]
VK	Investment in capacity [MW]
VS	Storage level [MWh]
VF	Fuel consumption [MWh]
Z	System costs [Money]
VU	Loading of storage [MWh]

In (3.1) the most important parts of the objective function is shown. The objective function consist of all system costs. The model optimize the objective function 3.1 given the constraints 3.2- 3.7 for the first specified year and loops the routine for all years specified, as seen in figure 3.1 and sums the results of the optimization procedures for all years.

$$\min \quad Z = \sum_{g,t} C^{\mathrm{f}}_{g,t} VF_{g,t} \tag{3.1a}$$

$$+ \sum_{g,t} C^{\mathrm{var,el}}_{g,t} VG^{\mathrm{el}}_{g,t} \tag{3.1b}$$

$$+ \sum_{g,t} C^{\mathrm{var,h}}_{g,t} VG^{\mathrm{h}}_{g,t} \tag{3.1c}$$

$$+ \sum_{r,ir,t} VX_{r,ir} (C^{\mathrm{imp,el.}}_{r,ir} + C^{\mathrm{exp,el.}}_{r,ir}) \tag{3.1d}$$

$$+ \sum_{a,g,e,t} W_{g,e} VF_{a,g,t} C^{\mathrm{ext}}_{e} \tag{3.1e}$$

$$+ \sum_{g} C^{\mathrm{fix}}_{g} (K_g + VK_g) + \sum_{g} C^{\mathrm{inv}}_{g} VK_g \tag{3.1f}$$

The first term in the objective function (3.1a) represent the fuel cost on technologies using fuel. The next two terms (3.1b) and (3.1c) represents the variable O&M costs of generating electricity and heat, respectively. The term (3.1d) is the transmission cost of electricity between regions. Revenues of exporting and importing is implicitly included in the model by allocating power between regions on transmission lines. If bottlenecks are present in the system the model include options to invest in new transmission lines. Cost of emission on fuel consumption is formulated in (3.1e). The equation (3.1f) represents the yearly instalment on investment in new technologies and the fixed yearly cost of the incumbent and the newly installed technologies. The instalments are corrected for the economical lifetime of the technologies. The objective function is subject to the constraints in the following equations.

$$\text{s.t.} \sum_{a \in \mathbb{A}} \sum_{g} VG^{\text{el}}_{a,g,t} + \sum_{ir} \left(VX^{\text{el.}}_{ir,r,t} - VX^{\text{el}}_{r,ir,t} \right) = D^{\text{el}}_{r,t} \quad \forall\, r, (ir \in \mathbb{R}), t \tag{3.2}$$

$$\sum_{g} VG^{\text{heat}}_{a,g,t} = DH_{a,t} \quad \forall\, a, t \tag{3.3}$$

$$VX_{r,ir,t} \leq KX^{\max}_{r,ir} \eta^{\text{loss}}_{r,ir} \quad \forall\, (r, ir \in \mathbb{R}), t \tag{3.4}$$

$$VF_{a,g,t} = \frac{VG^{\text{el}}_{a,g,t} + VG^{\text{heat}}_{a,g,t} C^{\text{v}}_{g}}{\eta_g} \quad \forall\, a, t, (g \in \mathbb{G}) \tag{3.5}$$

$$\sum_{a,g,t} VF_{a,g,t} \leq A_f \quad \forall\, a, t, (g \in \mathbb{G}^{\text{e.h.}}) \tag{3.6}$$

$$\sum_{a,g,t} VG^{\text{el}}_{a,g,t} \leq R_g K_{a,g} \quad \forall\, a, t, (g \in \mathbb{G}^{\text{e.h.}}) \tag{3.7}$$

The constraint (3.2) is the balance equation for electricity demand and supply. The power production is balanced interregional. The balancing of heat demand and supply is formulated in (3.3). The heat generation is balanced within each area. The limitation of electricity transmission is formulated in (3.4). Equation (3.5) is the fuel consumption of generation of electricity and heat for each technology taking their electrical and heat efficiency into account. Generation from technologies are limited by the capacity multiplied with an availability parameter, as seen in equation (3.7). In equation (3.6), generation on renewable technologies is constrained by the renewable potentials within the geographical entity.

4

Biogas Production and Upgrade Technologies

In this section, technologies regarding biogas production and upgrading of biogas are described. Upgrading technologies in each category are described, compared and the most relevant is selected for further use in the modelling.

4.1 Gas production from biomass

The conversion of biomass to gas can be split into two process types: Thermo-chemical and bio-chemical processes. The technologies in each process category can be seen in table 4.1. In the thermo-chemical category the technologies gasification and pyrolysis converts biomass to a gas commonly denoted as syngas. Syngas technologies are usually considered for dry biomass compunds. These technologies are still in the development stage and has not been looked into further. For the fermentation technologies in the bio-chemical conversion category, the main gas products is hydrogen along with various by-product gasses. The technologies include e.g dark fermentation or photo fermentation technologies. The Anaerobic digestion, AD, process converts organic compounds to methane by bacteria cultures. In this project only AD process is considered as this is the most cost efficient biomass to gas production method developed in present time, and there is no immediate development in the other processes that within the near future could lead to a more cost effective gas production process. The AD process can be split up in 4 main steps: Hydrolysis, fermentation, acid formation and methane formation. The process can be carried out at different temperature ranges; mesophile is around 35 °C and thermofile is around 52 °C. Higher temperatures yield a faster methane production process but is at the same time more sensitive to disturbance [22]. A more detailed walk-through of the AD process can be seen in the appendix A.1 in figure A.1. The product of the AD process is mainly carbon dioxide, methane and hydrogen sulphide. The gas yield depend on the biomass composition as seen in table A.1 and the level of digestion in the process. The energy efficiency of converting the organic solids to biogas is high as little heat is developed during the process. The amount of methane developed in the anaerobic digestion depends on the composition of the organic material. Fat is e.g high in energy content and almost the total energy content is converted in the AD process [39]. As

noted in chapter 1, the most common biogas production technologies in Denmark are waste water treatment plants, landfill biogas production and biogas facilities that utilize manure and other biomass resources. For this project waste water treatment plants and landfill gas plants are not considered any further, as they already have reached their potential for biogas production.

Table 4.1: Gas from biomass technologies

Technology	Product
Thermo Chemical Conversion	
Gasification	Syngas
Pyrolysis	Syngas, (biooil, char)
Bio Chemical Conversion	
Anaerobic Digestion	Biogas
Fermentation	Bio H2

The components of a biogas production facility typically includes: infrastructure for reception of biomass, pretreatment of biomass, reactor tanks for digestion, control and process regulation components, handling of digest, a gas storage and gas quality measurement instruments.
The average residence time of the biomass in the digester depends on the operational temperature. Typically larger facilities include a post digestion reactor as the biomass have had different residence times in the primary reactor, because batches have been added at different times. By adding fast converting biomass i.e biomass that has a fast digestion time, the production output can be regulated with a small time delay. The biomass suitable for regulation has besides fast conversion rates, a high gas potential, long storage stability and low nitrogen content [22]. Biomass with high nitrogen content can cause operational problems because it can inhibit the AD process. The practical regulation time may be smaller or larger depending on the specific biomass added to the digester. In general a low regulation time is desirable to secure a stable biogas process. Biomass fractions that are suitable for regulation are hereinafter referred to as energy crops as these constituate the major part of the biomass fractions that are suitable for seasonal regulation. The costs of biogas production facilities have been estimated in a report from Ea energy analysis [22] for both farm scale biogas facilities and central biogas facilities. The costs accounted for are both investment, transport of manure and operation and maintenance cost. PlanEnergi and Ea has investigated the extra investment and O&M costs needed for handling other biomass types in a biogas facility, in [22]. The costs covers pretreatment facilities and infrastructure. Distribution of biogas to consumers is by low pressure gas pipes. It is assumed that the same distance for low pressure gas pipes is needed whether the biogas is sent to upgrading or used locally, as in the "Biogas Task Force" report from Ea [22]. The economical and technical parameters related to the biogas production facility, the additional costs for different types of biomass, gas storage and low pressure gas pipes can be seen in appendixA.1.

4.2 Upgrade technologies

The term upgraded biogas is here used for biogas that is cleaned from sulphur components and other compounds, and has a Wobbe Index (WI) such that it fulfils the proper require-

ments of injection to the natural gas grid. In Denmark, requirements for upgraded biogas are defined for the contents of methane, carbon dioxide, sulphuric components, ammonia, oxygen and siloxanes. The definition of the WI of a gas is its energy content per normal cubic meter, divided by the square root of it's specific gravity to air. Other physical requirements should be respected, and the full requirements are described in [40],[41] and [42]. Two general types of upgrade technologies are are considered: technologies that upgrade biogas by removal of CO_2 and technologies that upgrade biogas by converting the CO_2 content of biogas to methane.

Upgrade by removal of CO_2

A variety of different upgrade technologies exist today for upgrading of biogas by removal of CO_2. The most relevant are reviewed briefly and are compared. The technology used further for modelling is described in closer detail. The main source of information for the upgrading technologies in this section was found in the report [43] from Swedish Gastechnical Center, SGC which has made a review of commercial upgrade technologies available in 2013. The report include reviews from relevant previous studies such as [44] and [45]. In the report from SGC the technical and economic details of the technologies has been acquired from operators of plants and plant manufacturers. Data for the technologies have been collected in appendix A.2. An overview of the total number of upgrading facilities in the world can be seen in table 4.2. Sweden and Germany are the market leaders. In Denmark 2 upgrade facilities are in operation [46], one water scrubber since 2011 and an amine scrubber since 2014.

Table 4.2: Overview of Upgrade facilities by removal of CO_2 in year 2012, from [43]

Upgrade facilities: Removal of CO_2					
Country	Sweden	Denmark	Germany	USA	Rest of the World
Facilities	55	2	96	14	53

Amine Scrubbers

The technology uses a reagent that chemically binds the CO_2 and thereby removing it from the biogas. The reagent is a water solution of amines, usually activated methyldiethanolamine (aMDEA)[43]. The technology generally consist of an absorber where the CO_2 is removed and a stripper where the the amine solution is recovered by heating. The methane content of the input biogas is reported in [43] from Swedish plants to be allowed in a range of 55 % to 70 % and have a maximum content of hydrogen sulphide, H_2S, of 300 ppm. Heat supplied to the stripper could be water supplied from the district heating network.

Water Scrubbers

The Water scrubber is a physical scrubber and the technology uses the physical property that CO_2 has a higher solubility than methane in water [43]. The CO_2 is separated from the biogas and dissolved into water in an absorption column by pressure of 6-10 bar. The CO_2 is released again in a desorption column. Energy consumption will be identical for raw biogas with different methane concentration since it will not affect the volume of circulated water.

Organic scrubbers

The organic scrubber technologies on the market are, as water scrubbers, physical scrubbers. In the scrubber CO_2 is absorbed in an organic solvent that has a higher solubility of CO_2 compared to the process in a water scrubber. The volume of the solvent that is recirculated is thus smaller, which leads to lower costs for some materials in the plant [43]. However the organic solvent has to be heated before desorption and cooled before absorption which leads to a higher energy expenditure.

Pressure Swing Adsorption

Pressure swing adsorption, PSA, is a dry method that separates the gasses by their physical properties. As the name implies the gas is compressed and fed into an adsorption column, that retains the CO_2 but not the methane. When the adsorption material is saturated the pressure is released and the CO_2 can be desorbed and led away [43]. The PSA technology does not consume water, and no heating is needed.

Membrane Separation Units

In membrane technologies the methane is retained on a membrane filter while most of the CO_2 permeates through. The raw biogas is cleaned for H_2S and water before being compressed and led through the membrane filters. The membrane technologies has a high methane recovery in general but some configurations have seen relatively low methane concentration. This has been solved by higher areas of membrane and/or higher compression and comes at a cost of higher energy expenditure and investment costs [43].

Comparison

Gas purity All nitrogen and most oxygen will end up in the upgraded gas for all units, however nitrogen and oxygen are normally not considered an issue in upgraded gas purity. All technologies except water scrubber needs removal of sulphur prior to CO_2 removal. In the amine scrubber a clean CO_2 stream is a by-product.

Consumables All techologies use 3 major consumables: Water, power and chemicals. The amine scrubber also has a heat demand but lower electricity demand than the other facilities.

Methane Emission Currently the PSA units have a methane emission, also called slip, of 1.8-2 % and Water scrubbers a slip of 1%, both which is relatively high. In [43] it is expected that subsidies for upgrade technologies will be tied with requirements for methane leaks as a sustainability measure. This will be an important factor for the economy for future gas upgrading plants as expensive tail-end solutions will have to be included to some technologies to decrease the methane leak. Amine scrubbers and membrane technologies have relatively low methane slips.

Investment costs The amine unit is the overall highest scoring unit in investment. However, at high throughputs the investment costs between the technologies does not vary significantly as seen in figure A.3 in appendix A.2. In general the development of the technologies has not led to any drastic decrease in either energy demand or capital costs the last 4 years [43]. The amine plants were demonstration plants in 2009 and is now commercial.

Water scrubbers and PSA are mature since many years and there has not been observed technological improvements that have led to cost reductions.

Gas compression Depending on the use of the upgraded biogas after it exits the facility the gas usually needs compression of some degree. For feeding it into to the gas distribution net, a pressure of 4 bar is needed. This can be done directly from the water scrubbers and PSA units. Gas from amine scrubber must be pressurized as the output pressure is around 1-2 bar. To feed into the natural gas transmission net requires 40 bar [47] and for vehicle upgrading is usually required at around 250 bar [43]. The energy needed to compress gasses is dependent on the pressure ratio, not the absolute pressure. The pressure at the outlet of the plant is of importance for the extra energy spend on compression. In this report it is estimated that compressing gas from 1 bar to 40 bar use around 0.15 kWh/Nm^3, whereas gas from 5 to 40 bar use 0.1 kWh/Nm^3. The estimation is explained in figure A.4 in appendix A.2. Minor differences in the composition of the biogas that can be observed from different biomass fractions will not alter the energy consumption of the compressor for upgrading the biogas.

Chosen technology PSA and water scrubber units have a a relatively high slip and as it is estimated in [43] that tail-end solutions to meet future methane-slip requirement standards will come at a high cost. PSA and water scrubbers have not developed in price and energy consumption in years, which could indicate that the potential of the technology has been reached. However as the gas pressure in the end-stream for these technologies are at the same pressure levels any extra costs would not be incurred to pressurize the gas if only delivering to a local low pressure distribution network. Amine scrubbers with their very low methane slip and the use of heat, possibly from the district heating network, and a clean CO_2 stream makes it possible that it can add to system flexibility: The CO_2 stream could potentially be converted to methane in a reactor with hydrogen from an electrolysis plant as done by the company Electrochaea in the project "Power-to-Gas BioCat2" [48]. Since the technology recently has become mature [43], there is a possibility that technical improvements can still take place such that investment and operation and maintenance costs can be reduced. In the recent years in Sweden the largest increase in market share is seen in the chemical scrubber facilities. Some membrane designs and organic solvent scrubbers have proven to have low slips. Organic solvent units have higher availability and lower O&M costs than membrane designs, but membrane technologies has lower slip. Both organic solvents, membrane technologies and amine scrubbers seem relevant based on their low slip. Organic solvent scrubbers have not increased their market share in recent years, and have stabilized around 10 % and membrane technologies have not yet been established on the market and are so far only available at low throughputs. Based on the recent increased market penetration the amine scrubber and the amount of data available for the technology, it is used in the model as choice of upgrade technology.

Amine Scrubber

Process Layout A simplified process flow diagram of an amine scrubber is shown in figure 4.1. The flow diagram represents systems in all ranges of facility sizes. The information for the operation of an amine facility was found in [43], and [49]. Using the numbers in figure 4.1, the process is explained. It is assumed that the majority of sulphur has been removed before entering the plant. The biogas is let into the absorber at (1) where it is mixed with the amine solution (10). The CO_2 and the H_2S reacts with the amine solution and is transformed

from gas to liquid phase. The amount of methane reacting with the amine solution is very limited and thus the process has a low methane slip. The phase transformation heats the temperature of the mixed solution. The pressure in the absorber is 1-2 bar in operation. The upgraded biogas is the remaining gas not reacted with the amine solution, and is let out at the top of the absorber. The remaining process concerns with removing CO_2 and H_2S from the amine solution and recycling it back into the absorber. The liquid phase CO_2 and H_2S exits the absorber at (3) and is preheated from the stripper-exit amine stream (8) in HX2. After preheating the liquid is let into the stripper (4). In the stripper the liquid is heated by HX1 which reboils it to release the CO_2 and H_2S. The stripper operating pressure is 1.5-3 bar. The heat from HX1 is added at 120-150 degrees Celsius and could be oil, hot water or steam. Some plants have been operated with water from the district heating system. In this case the stripper has to be operated under vacuum which requires additional electricity. A mixture of CO_2, H_2S and steam is let into a condenser (5) where it is cooled. All CO_2 and the remaining H_2S will be released here (6) and the remaining condensate, mostly consisting of steam and some amine returns to the stripper (7).

Operation 3 Areas of operational issues that are encountered are: 1) failure to meet specifications, 2) corrosion and 3) amine loss. Detailed explanation of the topics can be seen in [50] and [43]. The amount of contaminants in the raw biogas that can cause some of the listed operational issues such are typically H_2S, oxygen, nitrogen and organic compounds. The level depends on the source of origin. In biogas from an AD the most common contaminant is H_2S which is removed upstream of the scrubber by using an activated charcoal filter. The associated costs are included in the O&M.

Net injection For net injection the upgraded biogas needs compression after exiting the absorber. The compression level for injection is around 40 bar [47]. The energy used for compression is estimated from the figure A.4 in appendix A.2 for compressing from 1-2 bar to 40 bar is 0.12-0.15 kWh/Nm^3. The mechanical connection to the gas grid and adding an odorant to the gas is included in the unit. However the cost of the pipe leading to the NG gas grid depends on the distance and is not included in the costs of the unit. The total cost of net-injection have been estimated in an analysis from EA based on Danish experiences with upgrading projects. The summarized technical and economical characteristics for the amine scrubber is seen in appendix in table A.13.

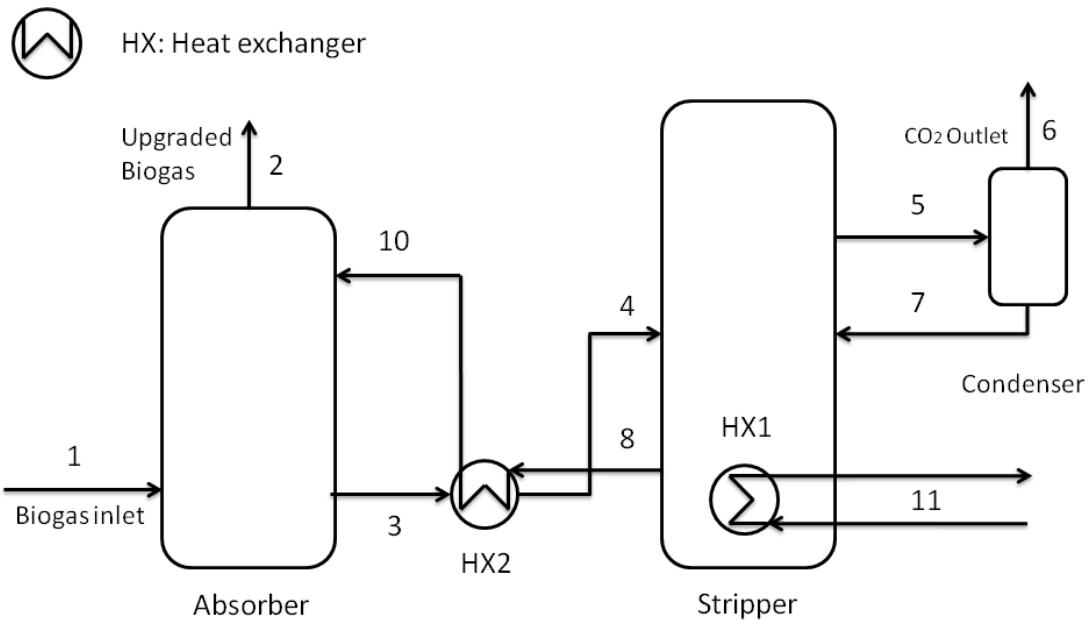

Figure 4.1: Flow Diagram: Simplified flow of amine scrubber for biogas upgrade

Upgrade by methanation of CO_2

Methanation of gases from thermal gasification has existed in many years as commercial technologies [51]. The content of gasses from thermal gasification have low contents of CO_2 and a high content of carbon monoxide, CO, and the technical layouts of the methanation processes have optimized facilitating the conversion of carbon monooxide to methane. Upgrading biogas by converting CO_2 to methane, has first recently received attention. Introducing biogas has called for different technical layouts and development of new technologies. In the Danish market two types of technologies for methanation of biogas are being developed, from companies Haldor Topsøe and Electrochaea, respectively. Topsøe is developing a technology solution for producing upgraded biogas with a high temperature catalytic methanation unit and production of hydrogen gas with a nickel-based solid oxide electrolysis cell. Electrochaea are developing a solution for the methanation process, and use a bacteria strain in a reactor that converts hydrogen gas and CO_2 to a upgraded gas with a high methane content [46]. Electrochaea has received funds from EUDP and FORSK-EL and are setting up a demonstration facility in Copenhagen. None of the technologies have yet been set up at commercial scale.
The system layout from Haldor Topsøe for upgrading biogas in a methanator combined with a SOEC for hydrogen production is used in this project. The technology is described further in this section. The economical and technical data for the components is gathered from [52], [51] and [53]. The data can be seen in appendix A.2.

SOEC

The Solid Oxide Electrolysis cell is developed by Topsøe fuel Cells, TOFC. The SOEC stack can be operated in different modes either by electrolysis or in reverse mode by producing electricity. In this project the possibility of using the SOEC stack for producing power when electricity prices are high, is not considered. The SOEC is designed to split steam into hydrogen and oxygen, providing hydrogen gas to the methanation process. The electrolytic

processes of splitting molecules are endothermic and requires electricity. In the whole chain of upgrading biogas the largest energy consumption takes place in this process. The SOEC unit is expected to have high part load efficiencies and good dynamic properties [52] which makes it suitable for flexible operation and can be modelled in a relatively simple manner. Electrolysis by SOEC is technically advantageous to alkaline and Polymer Electrolyte Membrane, PEM electrolysis technologies as it has a lower electricity consumption because it operates with steam and not liquid water [51]. These features, along with the fact that reliable data was available, makes the SOEC attractive and is thus chosen for the project over other electrolysis technologies.

Methanator

In the methanator the input gases are converted to a methane rich composition by a catalytic process. The process is exothermic, producing heat. A part of the heat can be recovered as steam and used as input to the SOEC or for other process heat demands. The dynamic properties of the methanator is as well expected to be good [52]. Before biogas enters the reactor, the sulphur content is brought down to a low level by a chain of reactors that absorbs contaminants with a high efficiency. Low levels of sulphur are needed in order to prolong the lifetime of the catalyst in the methanator.

Process

In [52] the economical feasibility of two different process configurations for using the SOEC stack with a methanator to produce upgraded biogas is considered. In the first configuration the biogas is added in the methanator and the input to the SOEC is steam and electrical power. In the second configuration biogas added to the SOEC. The first configuration was deemed most feasible and this configuration is used in this project. The process flow between the components for the system configuration can be seen in figure A.5 in appendix A.2 [52]. The oxygen flow from the SOEC, water flow to the methanator, and the condensate flow out of the methanator are not considered to be economically significant [52] and are therefore not included in the model development. As seen on the flow diagram A.5, the methanator can provide steam to the SOEC. As in [52] additional needed steam for the SOEC is produced by an electrical boiler. Additional steam can be needed if the methanation unit and SOEC are not operating simultaneously and or if the methanation unit capacity is low. Load changes in the SOEC can be realised without change in efficiency which requires that the SOEC is kept warm. According to [52] the amount of energy needed for keeping it warm is negligible and is not included. A minimum load level of the methanator is specified. Start-up costs are not included as the model used is linear.

5

Developed Model Add-on: Mathematical Description

5.1 Modelling a Generic Production and Storage Add-On of Green Gas Technologies in Balmorel

This section describes the developed add-on in general terms and with equations.
The add-on is a generic module with a detailed representation of biogas production and its further use in the electricity and heat sector, in a DH area in Denmark represented in the version of Balmorel from [17] developed by Ea energy analysis. In the Balmorel model all 420 Danish DH areas are aggregated into 48 areas. The largest DH areas in Denmark are represented by a single DH network, and smaller areas are aggregated as described in appendix A.4. In the developed add-on, the biogas model developed by Ea energy analysis in [22], with some modifications, is adapted to the Balmorel model. Furthermore the possibility of upgrading biogas by methanation and hydrogen gas from a SOEC unit is included in the add-on. The add-on makes it possible to optimize the production and use of biogas in the DH areas of Balmorel in coherency with the surrounding energy system, thus improving the representation of biogas and upgrading of biogas in the Balmorel model.

5.2 Description Of Model Components

This section describes the components of the model in a generic DH area and how they are linked in the model.
Biogas produced on biogas plants can be allocated locally in a DH area to the following consumers:

- Upgrading technologies
  - Amine Scrubber
  - Methanation of Biogas with a SOEC
- Local Production of electricity and heat, within the DH area

  - Investment in new biogas CHP and biogas boilers
  - Refurbishment of selected existing Gas technologies enabling them to use biogas.

- Production of electricity and heat on gas technologies after upgrading the gas to natural gas quality.

The biogas allocated to the upgrading facilities is injected to the natural gas grid and is available to be used in all DH areas in Denmark as upgraded gas.
The biogas can be produced from two types of biogas plants that has different input biomass compositions. The first plant has a high manure fraction with a flat output profile and the second has a high fraction of energy crops and the biogas production is allowed to be up- or down-regulated. The biomass composition alters the investment costs and operation costs as well as the fuel costs for the biogas production facility. The operational profile and the size of the biogas plant with seasonal regulation are determined by the optimization routine. For the manure plant, the size of the plant is determined by the optimization routine.
An overview of the geographical boundaries and the mapping of operational flow between the green gas technologies of a single heat area can be observed in figures 5.1, 5.2, 5.3 and 5.4. On figure 5.1 the geographical regions for electricity production is shown. Each country is split up in different regions that each has an electricity demand. Transmission lines between regions are denoted with black arrows. Denmark is represented by two electricity regions DK East and DK West that has a single transmission line between them and multiple transmission lines to other regions in the surrounding countries. Each region consist of DH areas where a heat demand is covered by the technologies in the area and the electricity demand is covered by the production of electricity in all areas plus import and export of electricity from neighbouring regions. Figure 5.2 displays a part of the electricity region western Denmark DK west from figure 5.1 where two heat areas denoted Nyborg and Odense, represented by circles with colors black and white, are shown. The add-on is developed for a single DH area and is subsequently applied to all 48 areas in Denmark
In figure 5.3 the flow of biogas, biomass and upgraded biogas within a DH area and the exchange of energy flows to the region is shown. The components of the DH area is illustrated as boxes/blocks with an acronym, and the flow between blocks are illustrated with coloured arrows. The explanation for each flow and acronym can be observed on the figure. The DH area boundary to the region is illustrated as a black circle that encompass the components and inside the DH area. With the boundary it is apparent which flows that take place within the area and which flows that are exported and imported with the region of which the area is located in. From the flow-diagram in figure 5.3 it is seen that biogas is produced from two biomass sources with manure and energy crops, respectively, as main components, denoted with acronyms *BMM* and *BMC*. The manure from *BMM* is restricted to the local manure potential. The Biomass available from the *BMC* is a regional resource. From the biogas plants (*BGPLANT*), the biogas can be allocated to a biogas storage (*BGSTO*), to the upgrading facilities (*BGUP*) or to the local biogas distribution grid (*GRID.L*). The local biogas CHP (*G.TECH*) can be provided with biogas from the biogas storage or directly from the biogas plant *BGPLANT*. Upgrading facilities *BGUP* are provided via the local distribution grid, directly from the biogas plant or from the storage.
In figure 5.4 the flow inside the upgrading block *BGUP* for methanation of biogas with use of a SOEC, and the flow between *BGUP* and the other components in the DH area is illustrated in detail. Besides the upgrade components, the flow diagram only displays components that are input and outputs to and from the upgrade components. The flow between the other system components are arranged like in figure 5.3. The *BGUP* block is here seen as a block with a dashed contour. Inside the *BGUP* block the methanator (*MTHR*) , the (*SOEC*) and

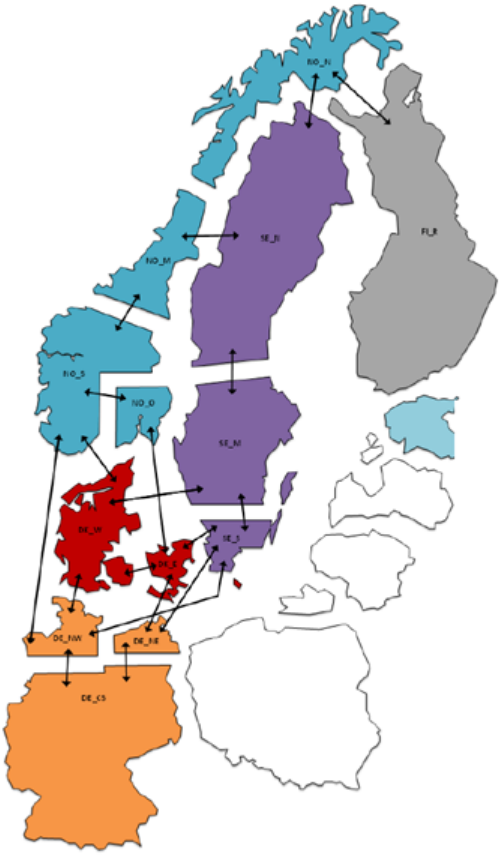

Figure 5.1: Electricity Areas in Balmorel

the hydrogen storage (*H2STO*) components, and the flows between, them are illustrated. The SOEC is producing hydrogen gas (H_2) that can be stored in a hydrogen storage and hereafter be used in the methanator to convert the CO_2 in the biogas which comes as input from a biogas storage. The SOEC has electricity delivered from the distribution grid, *GRID*. Steam to the SOEC can be provided from the methanator or by an electric boiler which adds to electricity demand in the region. Besides steam, the methanator also produce heat to the local district heating network.

5.3 Limitations

The model is limited concerning:

- Gas production to transportation use is not included in the optimization
- Flaring is not included as an operational parameter for units e.g gas engines.

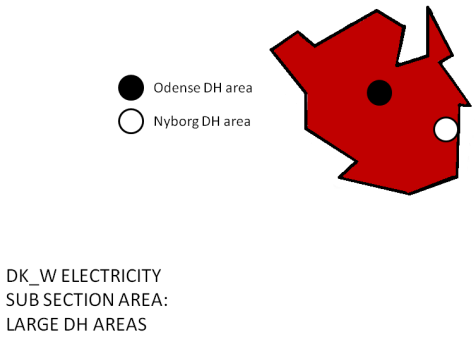

Figure 5.2: Excerpt of DK_W electricity region with 2 DH areas

- Process heat demand is included, but as a separate DH area as discussed in appendix A.4.
- The natural gas system is not modelled, it is assumed that the gas system can accommodate the upgraded biogas without extra costs.

5.4 Fuel Costs

This section explains how the fuel costs of biogas and upgade biogas is changed from the original model.

In the Balmorel version used by Ea in [22], the cost of using upgraded biogas for a technology is represented by including an fixed estimate of the whole chain of biogas production, storage and upgrading to the fuel price of upgraded biogas and delivery. For using biogas an estimate of the production chain from the biogasplant, biogas storage and delivery to the energy producer is included.
In the add-on, the cost of each step in the production chain of producing biogas and upgraded biogas is optimized separately in each DH area - in this way the biogas production, storage handling and biogas upgrade production profiles are optimized to the various DH area heat demands and local biomass potentials. The biogas fuel price for technologies in a local DH area is thus accrued in the production and delivery chain, in terms of investment costs, operational costs, fixed costs, biomass input costs and finally heat and electricity use is included in the area and regional heat and power balances of the model.
For each DH area the upgraded biogas receives a price for injection in the NG network, thus making it available for Danish NG technologies. The technologies that use NG does not distinguish between whether they use upgraded biogas or regular NG and the price they pay for the is the natural gas price. The upgraded gas sold to the NG grid, receives the price market price of natural gas plus the CO_2 quota price.

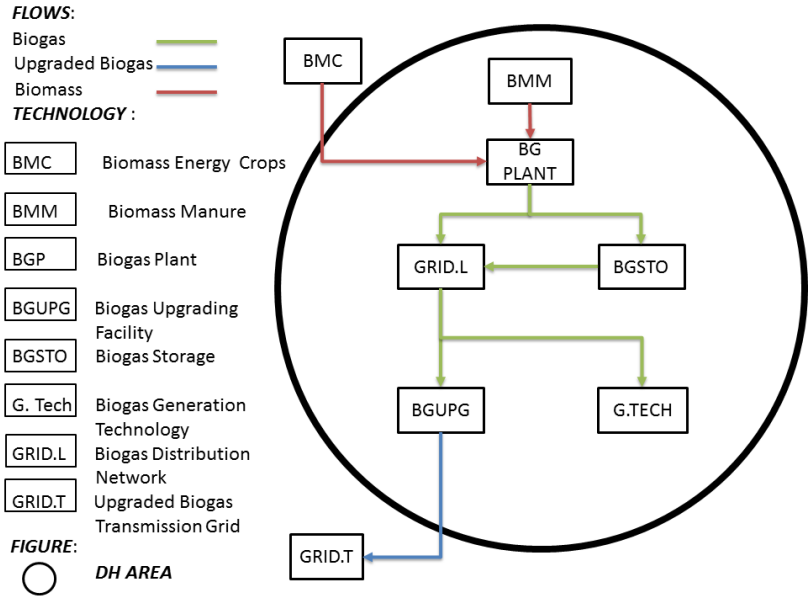

Figure 5.3: Flow Diagram: Green Gas Technologies in a DH Area

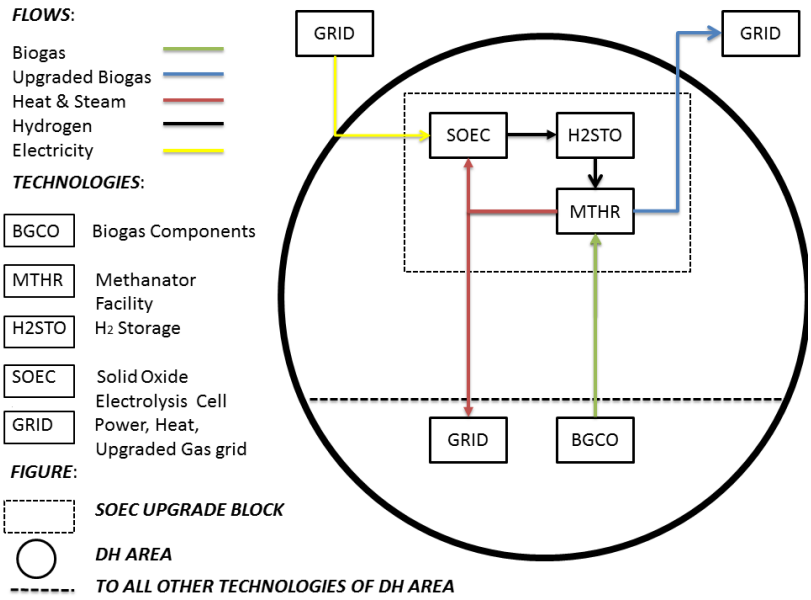

Figure 5.4: Flow Diagram: SOEC, Methanation and H_2 Storage in a DH Area

5.5 Equations

In this section the equations that make up the mathematical model of the add-on is presented. The add-on both consist of edited equations from the Ea in [22], new equations and some additions to the existing equations in the Balmorel version used in the report [17] from EA. The equations, in GAMS code, can be seen in appendix E.1, the editing of Balmorel equations in appendix E.2. The integration of the mathematical equations requires modifications to various files that initialise the model. An overview of all modifications for these files can be seen in appendix E.1. The sets, parameters and variables used to describe the mathematical equations of the add-on is shown below. The names for sets, parameters and variables does not necessarily represent the names used in the GAMS code, in order to make the equations appear clearer and to provide a better overview of them.

Sets and indices

$a, \mathbb{A}$	area, set of Areas
e	Relevant subset of $\mathbb{E}$, element in $\mathbb{E}$, set of energy flows
f	Fuel types
$g, ig, \mathbb{G}$	Relevant subset of $\mathbb{G}$, element in $\mathbb{G}$, set of generation technologies
$t, tf, tl, \mathbb{T}$	time step,first element in t, last element in t, set of time segments
$s, sf, sl, \mathbb{S}$	season, first element in s, last element in s, set of seasons
$r, \mathbb{R}$	region, set of regions
$el.$	Electricity
h	Heat
in	input from component
out	output from component

Parameters

C	Cost [Money/MWh]
C^{inv}	Investment cost [Money/MW]
C^{fix}	Fixed operation and maintenance cost [Money/MW]
C^{var}	Variable operation and maintenance cost [Money/MWh]
C^{ext}	Cost of externalities associated with emissions [Money/kg]
DE	Demand of electricity [MWh]
DH	Demand of heat [MWh]
R	Availability parameter
K	Existing capacity of technology [MW]
W	Emission factor [kg/MWh]
η	Fuel efficiency of generation technology
η^{loss}	Transmission efficiency
$KX^{\max}$	Maximum transmission capacity [MW]
A_f	Annual resource cap of fuel f [MW]
FB	Relative technology operation condition
FLW	Relative technology operation condition
BGQ	Biogas potential [MWh]
BGQ	Biogas minimum use requirement [MWh]
CAP^{min}	Minimum dispatch capacity [MWh]
$WHOUR$	Weighing factor of hours in time segment [Hours]

Variables

VG	Generation on technologies [MWh/h]
VX	Transmission of electricity [MW]
VK	Investment in capacity [MW]
VS	Storage level [MWh]
VF	Fuel consumption [MWh/h]

Z	System costs [Money]
VL	Loading storage [MWh/h]
VU	Unloading storage [MWh/h]
VW	Flow of energy [MWh/h]

To better represent the mathematical content of the equations that makes up the model, the equations presented are not necessarily stated in the same form as in the GAMS code. For instance variables are multiplied with each other, which from a model perspective makes it a non-linear problem. Non-linearities violates the solver boundaries and can as such not be handled by the program. In the model the non-linearities are avoided by manipulating the equations elements. The equations are also simplified in terms of the conditions for set domains, and by using one symbol for all subsets, instead of specifying all the different subsets for each equation. For example, relevant subsets of the set of technologies $\mathbb{G}$ is represented by a single symbol g. Relevant could in this context mean all new technologies introduced in a DH area regarding the biogas production and use, or all technologies using natural gas.

Flow Balance Equations

The production and use of biogas is modelled as a flow network consisting of vertices and edges. A vertex is a node that represents a component (ig) where energy flows (e) can enter and exit through edges to another component. Two vertices are distinguished: Sinks and sources. From a source only outgoing flows exist, and at a sink only incoming flows exist. The sink and source vertices are modelled with unique lp constrains. This applies for biomass input components BMC and BMM and the component $GRID$ as seen in figures 5.3 and 5.4. Edges between a component (ig1) and all other components (g) for a type of flow (ie) is described by the parameters FLW and FB which are both 3 dimensional matrices. The parameter FB controls the operational condition of each technology in the set $\mathbb{G}$ i.e the relative flow size of flow e that goes in and out of each component. For example the generation technology *BiogasUpg-AM* which is the amine scrubber facility, must produce $0.99MWh/h$ *Biogas_net* for every 0.049 MWh_{el}/h and 1 MWh/h *biogas* of input. The FB parameter for a selected number of technologies can be seen in table 5.2. The FB parameter is constructed such that at least one ratio either on the input side or output side equals 1. The ratio that equals one is the energy type for which the investment of the plant is specified for.

Table 5.2: Parameter FB

Technology	io	POWER	HEAT	BIOGAS	BIOGAS_NET	BIOMASS
BIOGASPLANT-CROPS.	in	-	-	-	-	1.240
BIOGASPLANT-CROPS.	out	-	-	1	-	-
BIOGASPLANT-MAN.	in	-	-	-	-	5.228
BIOGASPLANT-MAN.	out	-	-	1	-	-
BIOGASUPG-AM.	in	0.014	-	1	-	-
BIOGASUPG-AM.	out	-	-	-	0.944	-
BIOGASSTO.	in	-	-	1	-	-
BIOGASSTO.	out	-	-	1	-	-

The parameter FLW determines how the flow of energy types e can be allocated between

components g. In table 5.3 the FLW parameter value can be seen for selected technologies. If FLW(g,g,e) = 1 an edge between two components with flow type (ie) exist, and otherwise FLW(g,g,e) = 0. For example it can be observed that biogas can be allocated from a biogas storage (*BiogasSto*) to the biogas distribution grid (*GRID.L*) and the amine scrubber *BiogasUpg-AM* and the *Methanator*. The parameter is used for specifying conditionals on domains for sets applied to other parameters and variables in the equations. This can be observed in the GAMS code in appendix E.1. There is no limit to the size of the FLW and FB matrices, so new technologies can be accommodated.
In (5.1) - (5.3) the equations that balance the flows between components, except storage components, are shown. Equation (5.1) controls all technologies that has an in or output, by forcing the flow at each time period into a component VW relative to the flow balance parameter FB on the input side to be equal to the output flow relative to the FB on the output side. With this equation it assured that the right flow enter and leave a vertice at any given time. The construction of the equation where the flow is balanced according to FB parameter for both input and output allows for introducing losses in the components.
The equations (5.2) and (5.3) ensures that the right ratio of flows enters and leaves each vertice at each time step. Taking the input side as an explanatory example the left side of (5.2) is the ratio between the flow balance parameter FB for each flow type e and the sum of energy types for the flow balance parameter. The right side of the equation determines how much of each energy type will flow into the vertice, making sure that the ratio between flows are correct. The same principle applies for the flows on the output side in equation (5.3).

$$\frac{\sum\limits_{ie \in e} VW^{\text{in}}_{a,t,ig,ie}}{\sum\limits_{ie \in \mathbb{E}} FB^{\text{in}}_{ig,ie}} = \frac{\sum\limits_{ie \in e} VW^{\text{out}}_{a,ig,ie,t}}{\sum\limits_{ie \in \mathbb{E}} FB^{\text{out}}_{ig,ie}} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g), (e \in \mathbb{E}) \tag{5.1}$$

$$\frac{FB^{\text{in}}_{ig,ie}}{\sum\limits_{ie \in e} FB^{\text{in}}_{ig,ie}} = \frac{VW^{\text{in}}_{a,t,ig,ie}}{\sum\limits_{ie \in e} VW^{\text{in}}_{a,t,ig,ie}} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g), (e \in \mathbb{E}) \tag{5.2}$$

$$\frac{FB^{\text{out}}_{ig,ie}}{\sum\limits_{ie \in e} FB^{\text{out}}_{ig,ie}} = \frac{VW^{\text{out}}_{a,t,ig,ie}}{\sum\limits_{ie \in e} VW^{\text{out}}_{a,t,ig,ie}} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g), (e \in \mathbb{E}) \tag{5.3}$$

Maximum Capacity Constraints

The capacity constraints ensures that sufficient capacity for each component for the outgoing flow of energy types VW from a component ig. There are two types of capacity constraints , the first appearing (5.4) handles storage capacity and the second handles all other component capacities (5.5). For both equations the current capacity in that year plus the new capacity invested in in that year, both corrected for capacity outage R_{ig} and flow ration The parameter FB, should be equal to or smaller than the flow of energy VW at each time step.

$$VW^{\text{out}}_{a,t,ig,ie} \leq (VI_{a,ig} + K_{a,ig}) * FB^{\text{out}}_{ig,ie} * R_{ig} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g), (e \in \mathbb{E}) \tag{5.4}$$

$$VS_{a,t,ig} \leq VI_{a,ig} + K_{a,ig} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g) \tag{5.5}$$

Table 5.3: FLW Parameter

From *ig*	To *ig*	POWER	HEAT	BIOGAS	BIOGAS_NET	BIOMASS
GRID.	BIOGASPLANT-CROPS	-	-	-	-	1
GRID.	BIOGASPLANT-MAN	-	-	-	-	1
GRID.	BIOGASUPG-WS	1	-	-	-	-
BIOGASPLANT-CROPS.	BIOGASPLANT	-	-	1	-	-
BIOGASPLANT-MAN.	BIOGASPLANT	-	-	1	-	-
BIOGASPLANT.	GRID	-	-	1	-	
BIOGASPLANT.	BIOGASSTO	-	-	1	-	-
BIOGASPLANT.	BIOGASUPG-AM	-	-	1	-	-
BIOGASUPG-AM.	BIOGASUPG	-	-	1	-	-
BIOGASSTO.	BIOGASUPG-AM	-	-	1	-	-
BIOGASUPG.	NET	-	-	-	1	-

Biogas Policy Equations

In the E&F Balmorel model from [17] the biogas fuel is split in to 2 different fuel types; biogas from manure and biogas from energy crops. Upgraded gas is also split in two fuel types; upgraded biogas from manure and upgraded biogas from energy crops. This totals 4 fuel types. The generation technologies is in the model forced to consume an amount of each fuel type over the course of a year. The constraint is set such that for each fuel the sum of the fuel consumption for all generation technologies using the specific fuel type, for all areas over the course of a year, shall equal an specific amount. The amount relates to the total biogas potential in Denmark. This way of representing biogas and upgraded biogas consumption implies two assumptions which are not ideal. First of all it implies that the biogas in one area is available to all other areas. As mentioned in earlier sections and in the appendix E.1, this is a crude representation of the manure fraction in the real world, as the low pressure biogas networks are not interconnected and that the manure fraction is more or bound to it's geographical location because of transportation costs. Secondly it is exogenously given how much upgraded biogas that should be used. In this way the model does not optimize the amount.

To make a better representation of the manure production and use in the add-on, the constraint on use of biogas is set on the production of the two biogas types. The constraint for manure production can be observed in equation (5.6). Here the sum of the biogas from manure produced on biogas technologies (g, e) in each area (a) each year is enforced to produce $\sum_{t \in T} VF$ a biogas amount that equals the biogas potential allocated for the electricity and heat sector BGQ_a in that area.
As the biogas potential for energy crops is not bound to geographical location, the total biogas from energy crops (e), produced on biogas plants(g), over the span of the year is set to equal the energy crops potential BGP_This constraint is ensured by equation (5.7).

To ensure chronology between biogas flow (VW) to the technologies using biogas and their biogas fuel use (VF) in a DH area, the fuel consumption for biogas using technologies $(g1)$ are constrained to use exactly the amount of biogas e flowing from the biogas plants and biogas storage $(g2)$ to the low pressure grid in each time step t. This constraint can be observed in equation (5.8).

The model can choose the amount of biogas to upgrade to the natural gas network. As there is some flexibility in the network, it is not assumed that there should be the same chronology between upgraded biogas flow to the NG network and the consumption on NG technologies as in equation (5.8). However it is ensured that the total amount of upgraded gas (e) that is injected into the NG network from the upgrading facilities $(g1)$ over the course of a year is also used on generation technologies that use NG $(g2)$ in Denmark over the course of a year. The constraint can be seen in equation (5.9).

$$BGQ_a \leq \sum_{t \in \mathbb{T}, ig \in g, ie \in e} VW^{\text{out}}_{a,t,ig,ie} \quad \forall\ (a \in \mathbb{A}) \tag{5.6}$$

$$BGP \leq \sum_{a \in \mathbb{A}, t \in \mathbb{T}} VW^{\text{out}}_{a,t,ig,ie} \quad \forall\ (ie \in e) \tag{5.7}$$

$$\sum_{ig \in g1} VW^{\text{out}}_{a,t,ig,ie} = \sum_{ig \in g2} VF_{a,t,ig,ie} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ie \in e) \tag{5.8}$$

$$\sum_{a,t,ig \in g1} VW^{\text{out}}_{a,t,ig,ie} = \sum_{a,t,ig \in g2} VF_{a,t,ig,ie} \quad \forall\ (ie \in e) \tag{5.9}$$

Objective Function Editing

Variable Operation and Maintenance Costs In the Balmorel objective function *QOBJ*, editing was carried out to include variable costs of new technologies and to modify the fuel costs for biogas using technologies in the areas where the add-on is applied.
Flows between components incur variable operational costs. For the existing technologies the operational costs are multiplied by the generation variable $VG_{a,t,g}$, where as the new technologies are controlled by the variable *VW*. The operational costs for technology g of producing an outgoing flow of e from component g is specified by the parameter $C^{\text{var}}_{g,e}$. This can be observed in equation 5.10, which is added to the objective function *QOBJ*

$$... + \sum_{a,t,g,gi,e} VW_{a,t,g,ig,e} * C^{\text{var}}_{g,e} \quad \forall\ (g \in \mathbb{G}) \tag{5.10}$$

Biogas Fuel Cost For technologies whose output is not controlled by the *VW* variable i.e the original technologies of the Balmorel version, the use of fuel is related to a fuel cost, accounted for in the objective function. As the cost of biogas used as fuel on these technologies is accounted for by the production and storage of biogas and should not be included as a cost for the biogas using technologies in the areas where biogas production is implemented. The objective function in Balmorel *QOBJ* is edited such that the generation technologies in areas where the add-on is applied, are excluded from the set where fuel costs apply. This objective function can be seen in equation (3.1) in 3.3. The changes can also be seen in GAMS code in appendix E.2. This does not apply for upgraded biogas as this is first "sold" to the transmission net and then a cost is incurred by the use of upgraded biogas/natural gas when using it as a fuel on a gas technology. However the fuel price of upgraded biogas is corrected to represent the NG price, as the original price consisted of an estimate of the total cost of producing upgraded biogas.

Energy Demand Balance Additions

Components in a DH area that produce and use electricity and heat, determined by the flow variable VW, is linked with the rest of the energy system by including the flows of electricity and heat in the energy balance equations denoted *QEEQ* and *QHEG* in Balmorel. In the Electricity balance equation *QEEQ* the flow of power (e) to and from the components in the green gas producing technologies to the regional electricity grid ($g2, g3$) is added to the

original equation which balance the demand production of electricity, as seen in 5.11. For the implemented model, this includes electricity used in the upgrading components. For the SOEC the amount of electricity use depends on the steam production in the methanator. When the methanator and SOEC unit are not operating at the same time the SOEC produce the needed steam on an electrical boiler. The amine scrubber facility use electricity for every for upgrading for all time steps when upgrading takes place.

$$DE_t = \sum_{ig \in g1} VG^{\text{el.}}_{t,g1} + \sum_{a \in \mathbb{A}, ig \in g2, ie \in e} VW^{\text{in}}_{a,t,ig,ie} - \sum_{a \in \mathbb{A}, ig \in g3, ie \in e} VW^{\text{out}}_{a,t,ig,ie} \quad \forall\ (t \in \mathbb{T}), (ig \in g), (ie \in e) \tag{5.11}$$

The flow of heat (e) to and from the local DH area from components ($g2, g3$) is added to equation *QHEQ* in Balmorel in the same manner as the electricity flow. The modification can be seen in 5.12. In the model the only component interacting with the local DH area is the methanator which produce heat when in operation.

$$DH_{a,t} = \sum_{ig \in g1} VG^{\text{h.}}_{a,t,ig} + \sum_{ig \in g2, ie \in e} VW^{\text{in}}_{a,t,ig,ie} - \sum_{ig \in g3, ie \in e} VW^{\text{out}}_{a,t,ig,ie} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g), (ie \in e) \tag{5.12}$$

Minimum Capacity constraint

Load changes in the SOEC can be realised without change in efficiency which requires that the SOEC is kept warm. The energy calculations for this is not included in the model however the methanator is set to a minimum dispatch level of 20 %. This is implemented in the same style as the maximum capacity constraints, and can be seen in equation 5.13. The parameter CAP^{min}_{ig} specifies the minimum production level of the technologies.

$$VW_{a,t,ig,ie} \geq CAP^{\text{min}}_{ig} * (VI_{a,ig} + K_{a,ig}) * FB^{\text{out}}_{ig,e} * R^{\text{out}}_{ig} \quad \forall\ (a \in \mathbb{A}), (t \in \mathbb{T}), (ig \in g), (ie \in e) \tag{5.13}$$

Biogas and Hydrogen Storage

Biogas and hydrogen storages are in the model handled in the same manner. In the following a description of the biogas storage is given, that also applies to how the hydrogen storage is modelled. The biogas storage equation is handled in the same manner as heat storages in Balmorel, with a cyclical pattern over time steps t between season s. This means that the storage level (VS) of the last time segment in a season equals the first time segment in the season. In this way the end point storage levels between seasons does not need to be equal, and does not produce cyclical patterns between seasons. The storage equation can be observed in equation 5.14

$$VS_{s,t+1} = VS_{s,t} + (VL_{s,t} - VU_{s,t}) * WHOUR_{s,t} \quad \forall\ (s \in \mathbb{S}, t \in \mathbb{T}) \tag{5.14}$$

The storage level in the next time segment $VS_{S,T+1}$ holds the energy content as the previous storage level minus the unloaded heat (VL) plus heat loaded to (VU) the storage. The length of time segments t in Balmorel depends on the exogenously defined number of seasons and

time segments. In order to have the correct relationship between the dispatch level of a flow (MW) and the energy content of a flow (Mwh) for times segments, the time segment length is handled with a weighing parameter ($WHOUR_{s,t}$)that holds the hours of each time segment. The parameter is calculated in the original Balmorel model when defining seasons and time segments. For both biogas and hydro storages loss of energy is not included.

Seasonal Biogas Regulation

For biogas production with seasonal regulation the regulation time of scaling production from zero output to full load is 14 days and vice versa. In reality this may be done faster or slower, depending on the input biomass and the level of digestion. In the model developed for he Biogas Task Force by Ea [22], the gradient of production is handled by two equations that limit the up- and down-regulation of production level between two times segments. This is done with a cyclical pattern over time segments during a year. The basic mechanism of the equations is that: For up-regulation, the flow of biogas in the next time step minus the flow of biogas the current time step may not be larger than the gradient, and vice versa for down-regulation. However because the time representation in Balmorel is different than the model from [22] - it includes seasons and time segments, cycling over t in each s will inhibit the function of the original equations. Therefore the season and time sets are handled with linear set operators which handles the first and last time segments *(tf,tl)* of each season. The equations 5.15,5.16,5.17 handle the up-regulation between consecutive time segments and time segments between seasons. Equation 5.15 is the original equation handling the regulation of consecutive time segments in a season. In equation 5.17 the link between the last time segment of a season and the first time segment of the following season is handled, and in equation 5.16 the link between the last time segment in the last season *(sl)* and the first time segment in the first season *(sf)* is handled. The production level in time segment one in the first season can be set manually, neglecting equation 5.16. The equations for handling down-regulating of production is almost similar as can be seen in Equation 5.18,5.19,5.20. Running the Balmorel model in different time resolution has also been taken into account with the weighing factor $WHOUR$, but is not included in the equations shown here. See appendix E.1 with the GAMS code.

$$VW^{\text{out}}_{a,s,t+1,ig,ie} - VW^{\text{out}}_{a,s,t,ig,ie} \leq Grad(g) * FB^{\text{out}}_{ig,ie} * (VK_{ig} + K_{ig}) \quad \forall\ (a \in \mathbb{A}), (s \in \mathbb{S}), (t \in \mathbb{T}), (ig \in g) \tag{5.15}$$

$$VW^{\text{out}}_{a,sf,tf,ig,ie} - VW^{\text{out}}_{a,sl,tl,ig,ie} \leq Grad(ig) * FB^{\text{out}}_{ig,e} * (VK_{ig} + K_{ig}) \quad \forall\ (sf, sl) \in \mathbb{S}, (tl, tf) \in \mathbb{T} \tag{5.16}$$

$$VW^{\text{out}}_{a,s+1,tf,ig,ie} - VW^{\text{out}}_{a,s,tl,ig,ie} \leq Grad(ig) * FB^{\text{out}}_{ig,e} * (VK_{ig} + K_{ig}) \quad \forall\ (sf, sl) \in \mathbb{S}, (tl, tf) \in \mathbb{T} \tag{5.17}$$

$$VW^{\text{out}}_{a,s,t+1,ig,ie} - VW^{\text{out}}_{a,s,t,ig,ie} \leq Grad(g) * FB^{\text{out}}_{ig,ie} * (VK_{ig} + K_{ig}) \quad \forall\ (a \in \mathbb{A}), (s \in \mathbb{S}), (t \in \mathbb{T}), (ig \in g) \tag{5.18}$$

$$VW^{\text{out}}_{a,sl,tl,ig,ie} - VW^{\text{out}}_{a,sf,tf,ig,ie} \leq Grad(ig) * FB^{\text{out}}_{ig,e} * (VK_{ig} + K_{ig}) \quad \forall\ (sf, sl) \in \mathbb{S}, (tl, tf) \in \mathbb{T} \tag{5.19}$$

$$VW^{\text{out}}_{a,s,tl,ig,ie} - VW^{\text{out}}_{a,s+1,tf,ig,ie} \leq Grad(ig) * FB^{\text{out}}_{ig,e} * (VK_{ig} + K_{ig}) \quad \forall\ (sf, sl) \in \mathbb{S}, (tl, tf) \in \mathbb{T} \tag{5.20}$$

Continuous Biogas Regulation

To maintain a flat biogas production profile, the minimum production capacity of the manure biogas plant is set to 99 % as seen in equation 5.13.

6

Verification of the Developed Model Add-on

Verification

Before applying the add-on to all DH areas, basic functionalities of the add-on are verified. The verification is performed by implementing the add-on to 1 DH area and setting up case scenarios that can be compared to case scenarios from Ea in [22]. Furthermore the model is tested in selected situations with regard to the methanation and SOEC operational patterns.

Comparison with the Ea biogas model

The add-on is implemented in 1 DH area that has been specified to match the case scenarios in Ea [22], in terms of; 1) investment possibilities for heat and power production technologies, 2) existing technology capacity and 3) yearly amount of biogas production.
The Ea case scenarios investigates how biogas is used by an energy system comprised of 1 DH area, depending on whether the biogas is produced with a production unit that can regulate the biogas production (seasonal regulation) or if the biogas is produced with a continuous production profile. The time perspective is 2020 for the Ea case scenarios.
As the mathematical model used in Ea is only optimizing the investment of technologies and operational patterns for 1 DH area, and as such there is no interaction with the surrounding system; This means that a DH heat demand balance has to be satisfied, but the electricity is sold to the system at a fixed price.

Constructing the case scenarios The Ea case scenarios is 1 DH area with a net annually biogas production that covers 153 % of the DH demand in the area. In the DH area where the developed add-on is implemented, biogas can be dispatched to the following recipients:

- Refurbishment of existing NG CHP engine to BG
- Refurbishment of existing NG Boiler to BG
- Upgrading Units: Amine Scrubber and Methanation unit

To supply the DH area, the existing heat and CHP units can be used and investment in new production capacity can be undertaken. This includes biomass CHP engine, DH heat pumps, solar heat and wood chip boilers. Two cases are considered, as in the Ea case scenarios: Case 1 - biogas is only produced from the manure and organic waste fraction (from now on denoted MAN), which has a continuous production profile. Case 2 - Biogas is produced only from the energy crops fractions (denoted EC) where production can be regulated throughout the year as described in section 5.
The case scenario differentiates from the Ea mathematical model on some points: 1)Flaring on technologies using biogas is not implemented, 2) Biogas demand from the industry is not included, 3) The possibility to upgrade with a methanation unit is included, 4) The electricity balance equation with the remaining system is included in this case scenario, 5) The biogas production profile with energy crops is optimized as opposed to following a constructed production profile and 6) the water scrubber upgrade unit as used in the report from Ea is changed to an amine scrubber. Furthermore there is a risk that some differences in economic parameters for the technologies used, but they should be in the same order of magnitude.

Biogas production patterns and Heat demand of case scenarios The biogas production for the two cases is seen in figure 6.1, along with the the heat demand. Biogas production from energy crops is shown as the average for each season S in figure 6.1 to give a clearer indication of the operational level. The biogas production for each time step can be seen in appendix B in figure B.1, where the up and down regulation pattern can be observed. Each season S is represented by 6 time steps t. The 6 time steps are an aggregation of the 168 time steps that are the original Balmorel time resolution for each season (which can be interpreted as hours). The aggregation is based on an algorithm developed by Ea. The resulting aggregation of time steps can be observed in appendix B. The aggregation gives a less intuitive understanding when observing the results, as time step does not have the same time length, and subsequent time steps are not chronological.
The biogas production for Case 2 using energy crops follows to a large degree the seasonal variation in the heat demand. When the heat demand decrease, the biogas production decrease as well. The aggregation of the time steps makes the general heat demand characterized by having the highest peak in t001, another smaller peak at t004 and a valley in t005. In the months with with low heat demand the peak at t001 decreases. The heat demand in time period t004 also decreases, but relatively more than the decrease in t001. From S01 to S18 the biogas production is almost at a constant high output. When the heat demand starts to drop around S19 the biogas production decrease as well, though in some time periods the biogas production is ramped up to produce a relatively high amount of biogas compared to the heating demand, see e.g S26,S27 and S32 in figure 6.2. In weeks with high biogas production and low heating demand the electricity production on the Biogas engine is increased significantly. This can be observed in figure B.2 in appendix B.

Annual biogas use for case scenarios In figure 6.1 the yearly biogas consumption for the two case scenarios (production with MAN and production with EC) are displayed. The figure shows that when biogas is produced with a continuous profile (Case1,MAN), it is feasible to upgrade 5 % of the biogas with the amine scrubber. The upgrading takes place in the seasons with low heat demand, as the biogas should otherwise be used to produce electricity,be flared (which is not represented) or stored in a biogas storage. In case 2, when the biogas production can be regulated throughout the season, no upgrading takes place as biogas can be better utilized to match the DH demand profile. For case 1 the biogas used in

the biogas engine is 82 %, with 0 % production in condensing mode, and 13% of the biogas used in the boiler for heat production. For case 2, 78 % of the biogas is used in the biogas engine with 0% production in condensing mode. The rest (22 %) of the biogas is used in the biogas boiler. Furthermore it was observed that 14 % more electricity is produced by the biogas engine in case 1 compared to case 2 (not represented on figure 6.1), again ascribed to some seasons with a low demand for heat.

Results from Ea case scenarios In the socio economic case scenarios from Ea in [22] no biogas was upgraded. The biogas use in the case scenarios from Ea can be observed in figure B.3. For the Ea case that corresponds to case 1 in this chapter, around 80 % of the biogas is used in the biogas engine. Of this, 15% of the electricity in the engine is produced in condensing mode because of low heat demand in the summer period. The rest of the biogas is used in the biogas boiler. For the case that corresponds to case 2, the 82 % of the biogas was used in the biogas engine with around 4% of the biogas used to produce electricity in condensing mode. In Ea, only a very small amount of flaring occurred, which justifies that it is not included in the add-on.

Comparing the case results of the add-on in this report and the Ea case scenarios, it seems that the value to the system of upgrading biogas when producing biogas with a continous production profile is increased, when including interaction with the energy system, compared to the stand alone DH area from Ea. In the Ea model a part of the biogas was used to produce electricity in condensing mode. This is because the upgraded biogas in the add-on can be used on cost efficient technologies in other DH areas, that in turn lowers the cost of the total electricity and heat system. It was seen that when allowing the system to optimize the demand profile for the biogas regulation, it was beneficial for the system to up-regulate the production of biogas during some time periods in seasons with low heat demand. In these time periods the biogas engine was producing a high share of electricity. The reasons for this has not been further investigated, but could be linked to low wind power production resulting in a high price signal. No investments in methantion and SOEC technology was undertaken in the case scenarios. As the comparison showed similar results the model is deemed to be sufficiently verified.

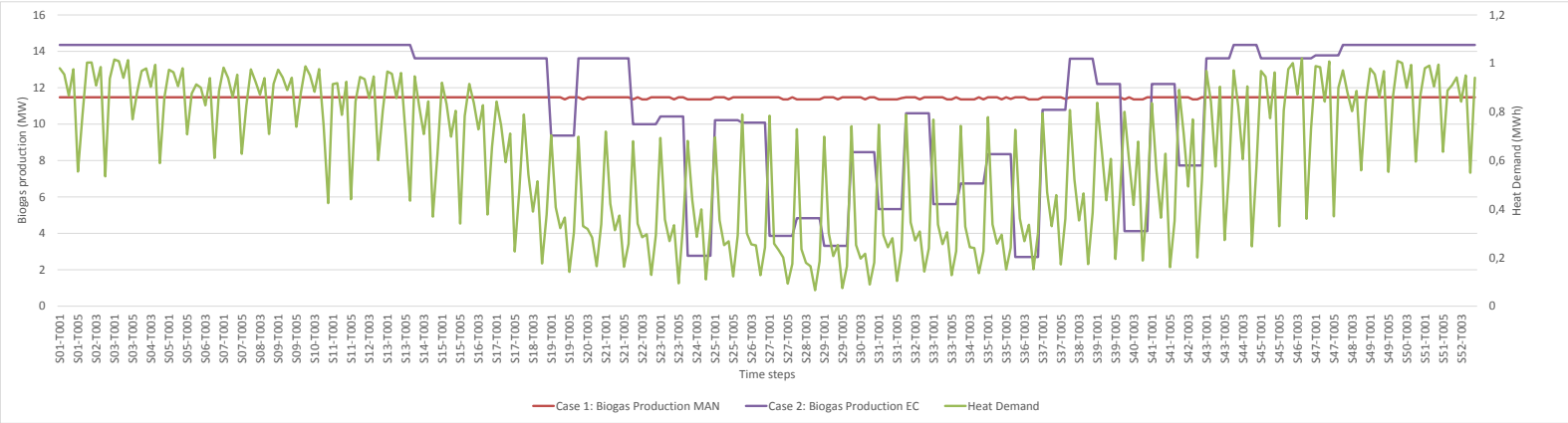

Figure 6.1: Biogas Production profile and heat demand for case 1 and 2

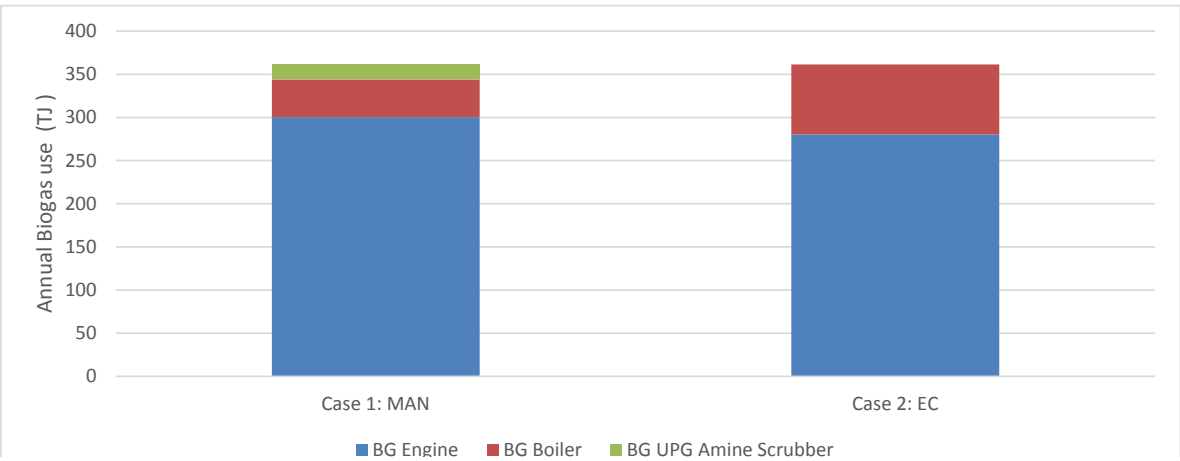

Figure 6.2: Annual Biogas Use for case 1 and 2

Verification of the SOEC and methanator operational pattern

In the case scenarios from the previous section, no investments was made in the SOEC and methanator. To verify the operational patterns of the technologies an amount of biogas is forced to be utilized in the methanation unit over the course of the year. The further operation of the methanator and the SOEC is optimized by the solver. Case 1 scenario settings from the previous section, where biogas is produced by a manure biogas plant, is used. Of the total amount of biogas produced, 25 % is constrained to be utilized by the methanator over the course of the simulated year. The operation of the SOEC is observed in figure 6.3 along with the simulated electricity price. The output in MW for the SOEC unit is shown for each time step in seasons S01-S14, out of the total 52 seasons simulated, on the left vertical axis. The right vertical axis denotes the electricity price. From the graph is can be observed that the SOEC is generally producing in peaks, with 750 full load hours during the year. The time-steps when producing most hydrogen coincides with time steps where the electricity price is low,providing up-regulation (from a demand side perspective) to the system, see e.g S02 T005 and S06 T006 on the figure. There is never production when the electricity price peaks. In some periods the SOEC is producing while the electricity price is around average, to comply with the methanator minimum load constraint as seen in figure 6.3 where the production pattern of the SOEC and the methanator is observed. The methanator is seen to have long periods of time when it is producing on minimum capacity e.g from s06 t001 to s08 t004, while the bulk of the production takes place in few time steps. In these long time periods of running on minimum production it could be considered to let the methanator shut down to get more cost effective operation. This is discussed further in section 9. The operational pattern of the methanator and SOEC is verified based on the results.

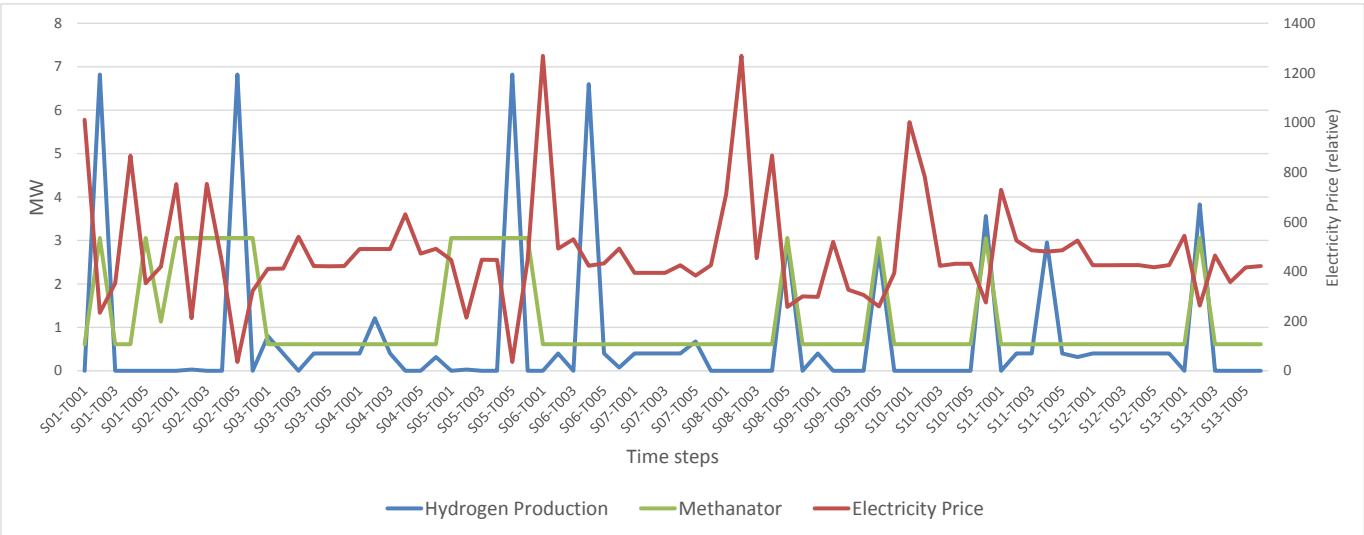

Figure 6.3: SOEC and Methanator Production

7

Scenario Analysis using the developed Add-on

3 scenarios are established for analysing the biogas production and use in relation to the research questions. The countries included in the scenarios are: Denmark, Norway, Sweden, Finland, Germany. In the baseline scenario existing policy goals and targets for the electricity and heat sectors are implemented. Furthermore two scenarios that outline different paths for the electricity and heat sectors with focus on biogas and biomass are implemented. The baseline scenario can be seen as a business as usual scenario, against which the two other scenarios can be compared. The scenarios are explained in detail in the following sections. The baseline scenario has to some extent been adopted from the scenario used in the E&F analysis from Ea in [17]. Taken into consideration in the analysis are years 2020, and 2035. These years represent important benchmarks in the energy policies for both European countries and Denmark in a short and medium term perspective. The long term perspective of 2050 is not included. An overview of the different scenarios can be seen in table 7.1. The two scenarios "Boilers" and "Biomass" are analysed in both years 2020 and 2035.

Table 7.1: Scenarios

Type	Scenario Name	2020	2035
Socio Economy	Baseline	x	x
Socio Economy	Boilers	x	x
Socio Economy	Biomass	x	x

7.1 Baseline Scenario

The baseline scenario is intended as a business as usual scenario, that exemplifies how the electricity and heat sector will most probably develop, based on the current political plans and goals of the European countries. The political goals and targets for all countries are implemented in the analysis for year 2020. After 2020 only the current Danish political goals

and targets are implemented, but the common goal of reducing the CO_2 level as formulated by the UN Climate Commission and accepted by the European countries in 2008 [54] is included in the scenario.

Implemented Policy Targets In 2020 & 2035

- Renewable targets for included countries national actions plans [55] are implemented in 2020 as a minimum. The further investments are decided by the model, except for Denmark
- For Germany their action plan "Energieconzept 2050, Scenario IIA" [56] are implemented for wind power which is 220 TWh wind in 2050.
- Biomass such as wood chips and wood pellets can be imported at a limited amount to limit early investments as it is assumed that the biomass are not imported in the long run in 2050. Otherwise the use of other biomass fractions is restricted to each individual country's own supplies.
- The biomass available for the electricity and heat sector is limited to 50 % of the total potential as it is assumed that the biomass should be used in other sectors, primarily the transport sector.
- CCS is not allowed in any countries.
- The national production of electricity shall equal 100% of the electricity demand. This is not a political goal, however it seems reasonable to ensure self sufficiency on electricity in line with the general political goal of total independence of fossil fuels in the whole energy sector by 2050. The national supply is enforced by ensuring that the total produced electricity in a year shall equals 100 % of the total electricity demand.
- For CO_2 reductions each year a step on the projection towards a 95 % reduction of CO_2 emissions in 2050 is applied for Germany and the Nordic countries.

Policies For Denmark

- Deployment goals for wind and solar power for 2035 as used by Energinet.dk in [57].
- 2020: 30 % National supply of energy by renewable energy resources, 50% electricity covered by wind [58].
- 2035: No fossil fuels in the electricity and heat sector in Denmark [59]. GHG emission from burning waste is allowed for electricity and waste.
- No investments in capacity that use fossil fuels, besides gas plants that use upgraded biogas. The model can refurbish existing plants to accommodate use of biogas.
- Rules from Projektgodkendelsen [59] regarding establishment of biomass boilers are enforced. This means that investments in biomass boilers in DH areas supplied by de-central natural gas CHP cannot take place. Establishing Heat (heat only) production units to a DH network supplied by de-central natural gas CHP or natural gas heat boilers can only be allowed for technologies that use the fuels Natural gas and mineral oil. The law is intended to secure natural gas CHP not being displaced by biomass. Fuels are in the definition not used about solar heat and geothermal units, and electric boilers and heat pumps and these can as such be chosen for investments.

Biogas potentials Denmark

Of the total biogas potential of 48 PJ in year 2020 as calculated by Agrotech in [1], with some fractions revised in the report from Ea in [22] such as straw and municipal waste, only around half is assumed to be available for the power and DH sector. The biomass for biogas is divided on two types. Type 1 is comprised mainly of fractions which have to be used continuously during the year, such as manure and organic waste (MAN). Type 2 is mainly comprised of biomass which can be stored such as straw and energy crops (EC). MAN accounts for 49% of the available biogas, EC accounts for the remaining 51 % biogas. The maximum biogas potential in Denmark as estimated for year 2020 is first available to the system in 2035, to take into account system planning and technology development for increasing the biogas conversion from straw. The availability of the biogas fractions can be seen in figure 7.1.

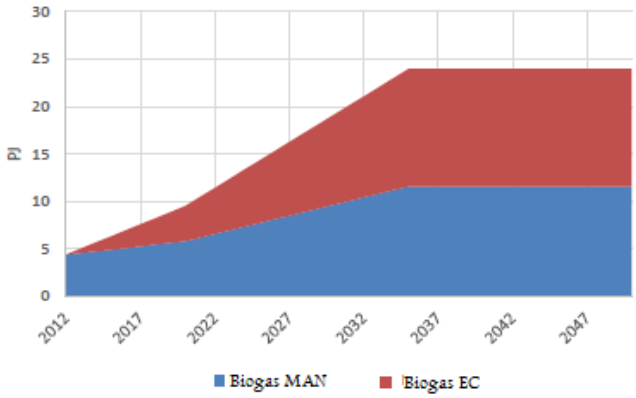

Figure 7.1: Biogas Potential Denmark available to the electricity and heat sector, from Ea in [17]

Biogas potentials assigned to DH Areas in Balmorel

The biomass fraction MAN is considered a resource that is linked to a geographically restricted area for use, because of high transportation costs. For this thesis each of the 48 DH areas have been assigned a biogas potential. The available data for the biogas potentials comes from the project "Biogas Task Force" where companies PlanEnergi and Agrotech has calculated the manure potential (consisting of manure, liquid manure, deep litter) assigned to each municipality in Denmark by use of GIS software. Two assumptions are: 1)The biogas potential in each municipality can only be used by DH areas within the municipality. This deviates from actual conditions, as there is no reason why manure from a farm close to the border of two municipalities cannot be used on a biogas plant in the neighbouring municipality. 2) The second assumption is related to how to assign the biogas potential within a municipality to the existing DH networks. This is especially related to the aggregation of the DH networks as described in appendix A.4. It is assumed that each DH network in a municipality (DH area as assigned to the model) and the industry that produce process heat, gets an equal share of the biogas potential in the municipality. This assumption also

deviates from actual conditions as the biogas potential typically is located in rural areas where typically the small DH areas are located, and the industry is typically further away from the biogas potential [22]. Even these generalized "typical" conditions varies with local geography. Since there is no apparent way of solving this problem more satisfyingly within the time scope of the report the relatively simple geographical distribution of the biogas potential, as just described, has been chosen. The resulting distribution of biogas from manure is seen in table A.19 in appendix A.5. In the appendix figure A.8 shows the biomass potentials, heat demand and number of DH areas that has been aggregated small DH areas can be observed.

Additional Scenarios

For both the "Boiler" and "Biomass" scenario, only a few changes are made compared to the Baseline scenario to ensure that the resulting consequences in the optimization process and their cause can be distinguished from each other in the analysis. For both scenarios, conditions and policies in countries included in the analysis, with Denmark as an exception, are the same as in the Baseline scenario. Many scenarios could be investigated to analyse the influence of biogas technologies to the energy system, but due to the limited time scope of the assignment two scenarios have been chosen. The Biomass Boiler scenario represents a change in the current rules for national DH planning, whereas the Biomass scenario represents a change in resource availability in the surrounding system.

7.2 Boiler Scenario

The difference from the baseline scenario in the boiler scenario it that it is allowed to invest in heat boilers that use biomass in DH areas with natural gas production. After the oil crisis in 1976 the Danish energy politics was targeted at replacing oil in the heat and power system with natural gas and has over the years been subsidized heavily to secure the economy of the NG CHP plants. With the shift in Danish energy politics towards reducing CO_2 emissions and securing the supply of energy, natural gas is planned to be phased out in 2035. The construction of the current subsidy schemes favours electricity and heat production from renewables such as wind and biomass. The goal is that biomass heat and electricity should replace central NG CHP in large DH areas as this has shown to be the most efficient way to cut CO_2 emissions. Biomass boilers, including biogas boilers are however not allowed in de-central DH areas with NG production [59] as this is deemed least feasible from a socio economic perspective [60]. In the scenario it is important to analyse three factors that is linked to the feasibility of a possibly large investment in biomass boilers. First, is the lost revenue for the gas transmission and distribution companies not receiving revenue from using NG. Included in the revenue is charged a tax that is securing funds for the repayment of the NG transmission and distribution network. According to [61] and [62], the gas transmission net is repaid within the end of year 2029, and the distribution networks within 2026. According to a report from DI [63], if investments was allowed the private economy conditions will most likely spur large investments in biomass boilers in de-central areas, because of the bad economy of many NG CHP plants. In the analysis it will be discussed if potential benefits of removing the biomass boiler act outweighs the lost revenue to repay the gas transmission and distribution networks if NG is displaced by biomass. Another factor to consider is a possible lower total energy efficiency and relocation of CO_2 emissions between countries. Even though a local CO_2 abatement will take place if substituting NG CHP on the relative inefficient gas motors in de-central areas by producing heat with biomass boilers, the overall

goal of abating CO_2 is not necessarily secured, as the reduced electricity production on the NG plants could induce production in e.g a condensing coal plant. In Denmark coal is used until 2030, but is still allowed in e.g Germany. Condensing coal plants where the heat is not used, can lead to a lower total efficiency per energy produced which both leads to a higher energy use and larger green house gas emissions. If this is the case it might be politically infeasible to remove the legal requirement to the biomass boilers in de-central areas. Furthermore a possible early large investment in biomass boilers should be analysed. If the biomass import limits are reached already in 2020 it can be discussed if the investments are really optimal, as there after 2020 is expected a decrease in the allowed import of biomass. As the model does not look ahead in the following years, it could be a problem if too much capacity is invested in that in the future does not have sufficient fuel in order to be operated with the optimal operating time - thus other investments would have been more optimal.

7.3 Biomass Scenario

In the Baseline Scenario the allowed import of biomass is restricted to 300 % of a country's own potential in 2020 and 200 % in 2035. The decline in allowance of imported fuels is based on the expectation, that every country in time, to a certain degree, will utilize their own biomass potential as fossil fuels become scarce and hence, more expensive. In the latest report from IPCC on renewable energy [64] it is estimated that around 100-300 EJ of Bio energy is globally available in 2050 with an estimated energy use of 900 EJ. In the Biomass scenario it is assumed that the available imported biomass is limited to a smaller amount than in the Baseline scenario. The decrease may be explained by a quicker transition to biomass based energy consumption in the countries from which import is now available, which again can be explained with increased renewable targets and/or rising prices of fossil fuels. For the Biomass scenario the import of wood pellets and wood chips allowed are lowered to 100 % of own national resources in 2020 and 0 % in 2035. Waste, straw and other biomass which are expensive due to transportation costs are still limited to national resources. The limitation in biomass will likely increase the value of biomass based fuels and it could be expected that an increase in production of upgraded gas will take place, such that the fuel can be used on technologies with higher efficiencies. Depending on the value of energy from fuels to the system, the methanation plants could play a role as they can add the available amount of upgraded gas caused by the energy conversion of CO_2 from the biogas and H_2.

7.4 Verification of model constraints in Baseline Scenario

In the E&F analysis from Ea [17] a number of constraints is imposed on the system, that has been set with the goal of "controlling" the model optimization to behave in a realistic manner. Three of the constraints are investigated with the purpose of determining how the optimal solution for the baseline scenario will be like with and without them, and to determine if they are indeed needed. The constraints that are subject to testing are seen in table 7.2. The constraints are explained in the following section.

Table 7.2: Validation of Baseline Scenario

Type	Baseline	2020	2035
Validation	Transmission Limitation		X
Validation	No Biogas Use Enforcement	X	X
Validation	Investment in fossil fuels	X	X

Transmission Limitation

In the analysis the planned transmission capacity between regions in the model until year 2025 is installed in the respective years of the official project deadline. After 2025 a question to raise is how much investment in transmission capacity between countries should be allowed as a maximum cap. In the E&F analysis from Ea [17] which this analysis use as reference, the general allowed installed capacity between a country and it's neighbouring countries is assumed to be 1500 MW every 5 years after 2025. In Denmark the expansion is limited to 1000 MW per 5 year period as it is assumed that the large expansion from Danish territory taking place until 2025 will reduce the political will to invest in transmission capacity in the subsequent years. The argument behind the limitation is based on the expectation that a single country have a low will to install large transmission capacities for the primary benefit of the surrounding countries. The benefit for the surrounding countries lies in electricity price equalisation. Furthermore the model does not see the import and export and thereby the impact on electricity prices, of countries outside the geographical scope of the analysis. Expanding the geographical scope could lead to both higher or lower investments between the transmission capacity, depending on the electricity price profiles of the expanded geography. This especially has implications for Germany as there are many possibilities for transmission capacities not available in the analysis as opposed to real world options. For year 2035 the transmission capacity limitation is tested for the basis scenario for two cases: the first case one having transmission capacity restrictions as in the E&F analysis, the second case the max restriction is increased 5 fold to 5000 MW per year. Year 2020 is not included as the transmission capacity investments are included exogenously.

Results: In table 7.3 the investments in transmission capacity between Danish regions DKWest and DKEast to neighbouring regions are shown for year 2035, for the baseline scenario with and with an investment restrictions of 5000 MW per year for Denmark. Thus the restriction amounts to maximum 10000 MW in 2035. An "x" between 2 regions indicates that transmission capacity is not possible. For the baseline restriction, the 2000 MW limit is fully utilized, with the connection DK West -> NO South as the largest expansion. With the maximum allowed capacity cap raised to 10000 MW the full allowed capacity is also utilized, with connections DK West -> NO and DK West -> DE NorthWest as the two largest transmission capacities. The effect of the transmission investments is partly reflected in the electricity prices. In figure 7.2 the average electricity price in 2035 for Denmark, Norway and Germany can be observed with the baseline restriction and the relaxed restriction. From the figure it is seen that the price in regions of Germany and Denmark are lowered and the price in the total Norwegian region is increased. The average electricity price is lowered with 6 % for Germany, Denmark and Norway when comparing the two cases. This concludes that investments in transmission capacity to a 10000+ MW level will be undertaken if allowed, thereby seeing an equalising effect on the electricity price in the areas where the largest transmission capacity is expanded. For this project the prior limitation as used by Ea in

[17] is used for the main analysis, as it seems unrealistic to let transmission capacity be decided by the optimization routine without constraints.

Table 7.3: Investments in transmission capacity between Denmark and neighbouring countries for baseline restrictions and raised investment cap

Transmission limitation (MW)	DK East	DK West	DE NorthEast	DE NorthWest	NO South	SWE South	SWE Mid
DK East	x	0	0	x	x	0	x
DK West	(0)	x	x	0	1.694	x	306
Transmission maximum raised							
DK East	x	279	0	x	x	0	x
DK West	(279)	x	x	2.764	6.298	x	938

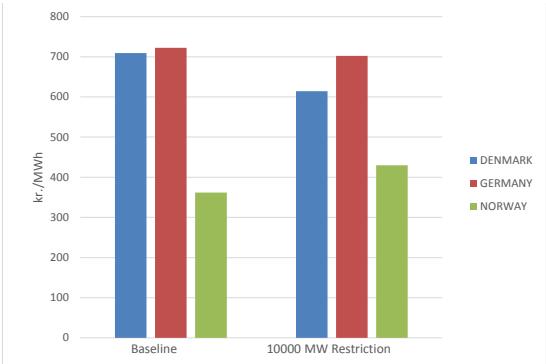

Figure 7.2: Average electricity price for Denmark, Norway and Germany for year 2035

Enforcement of Biogas Use

As a starting point for the scenario analysis in the Ea scenarios [22] an exact amount of produced biogas from both biogas fractions in both 2020 and 2035 is enforced. As discussed in section 2, all externalities of biogas production and use are not captured in the analysis, and thus the full value of biogas to the system is not reflected in the optimization routine. However even without including all externalities from biogas production and use, it could have a value for the energy system when considering future fossil fuel restrictions from political side and resource scarcity that expectedly will drive market prices for fuel upwards. As the analysis is concerned about the years 2020 and 2035 the optimization routine may choose not to invest in any biogas technologies in 2020 as fossil fuels is still available in Denmark and fuel prices are still relatively cheap. If the model subsequently in 2035 invests in large amounts of biogas technologies, with no preceding biogas investments in 2020, this misaligns with the expectation that investments have to take place gradually in the market. If this case unfolds there is thus a need to implement a constraint that force investments

in capacity in 2020 (if the model choose to invest in large amounts of biogas in 2035). In accordance with the political target of biogas production in 2020 as mentioned in the introduction 1 the constraint could also be necessary to ensure the target being reached.

Results: The results from the baseline scenario with no biogas use enforcements can be seen in table 7.4. There are no investments in biogas production facilities or further upgrading in 2020 and 2035 if it is not enforced by constraints. To reach the political goals for manure use constraints needs to be set for the analysis.

Table 7.4: Biogas use with no enforcements in 2020 and 2035

	Upgraded Biogas (TJ)	Biogas (TJ)
2020	0	0
2035	0	0

No Investments in Fossil Fuels

In the baseline scenario a constraint is set such that investments in fossil capacity is not allowed in 2020. The constraint is implemented in order not to spur high investments in fossil fuel capacity in 2020 that cannot be used in 2035 when the Danish heat and power sector should be covered by 100 % renewable energy. The constraint takes into account that the model only optimize investments for a one year time horizon at the time - thus not have the ability to optimize for a whole range of years coherently, as discussed in chapter 3. However it is reasonable to check if the total system cost are reduced or increased for the total period of 2020 and 2035 when allowing fossil fuels to be invested in, in 2020.

Results: The Annualised costs for the base scenario with and without investment in fossil fuels in 2035 can be seen in table 7.5. The value for both cases is the sum of year 2020 and 2035. The annualised costs are larger for the case where fossil investments are allowed in 2020, with a difference of 48 MEURO14 to the base scenario with no fossil fuel investments. Allowing the model to invest in fossil fuels in Denmark in 2020, around 700 MW coal capacity is installed. The coal capacity is however be decommissioned again in 2035, and is replaced by new fossil-free capacity. In conclusion a constraint that limits fossil fuels investments in 2020 is sensible to include, because a higher total system costs otherwise will be incurred due to the limitation of the Balmorel tool, that cannot optimize over longer time periods than 1 year.

Table 7.5: Total system cost for Baseline and Investments in Coal Capacity

Invest in Fossil(MEURO14)	Base(MEURO14)	Difference(MEURO14)
86158	86109	48

8

Results

8.1 System Investments and existing Capacity

For all 3 scenarios in 2020 the main investments in electricity generation is based on Natural Gas (2300 MW), with a small amount of wind (70 MW) and biogas CHP as seen in figure 8.2. The biogas CHP capacity investment for the baseline and biomass scenarios is 150 MW. In the boiler scenario the capacity is 20 MW lower as this is substituted by biogas boilers for heat production as looked into later in this section. No coal is invested in, according to the constraint mentioned in section 7.4. The seemingly low investments in wind power are the extra investments to the exogenous wind capacity that is already implemented in the scenarios in 2020. In figure 8.1 the total installed electricity capacity (the existing capacity minus the decommissioned capacity, plus the newly invested capacity) can be observed. Here the total installed wind power is observed to be 5800 MW for all scenarios in 2020 which account for 40 % of the total electricity capacity. The other capacities include Natural gas (25 %), coal (13%), wood pellets (6,5 %), solar (6,5%), light-oil, waste and wood.

In 2035 the main investments in electricity production are wood CHP (50% of new investments) for the baseline and boiler scenarios as seen in figure 8.2. In the biomass scenario the wood CHP investments are considerable lower (13 %), and is substituted by wind power production that amounts to 33 % of new electricity investments and a higher straw CHP production, 70 MW in the baseline and boiler scenario to 280 MW in the biomass scenario. This difference is related to the limited biomass availability caused by the resource restriction in the scenario. New biogas capacity is the same between scenarios with 5 % CHP capacity. As seen on figure 8.2 there is a small amount (50 MW, 44 MW and 65 MW in the scenarios, accordingly) of new natural gas capacity installed in 2035. The capacity is used to for upgraded biogas as natural gas fuel is not allowed in the scenarios in 2035. The total electricity capacity in 2035 as seen in figure 8.1, and it observed that coal capacity is decommissioned. Wind power is the dominating technology with 7800 MW for the baseline and boiler scenario and 9400 MW for the biomass scenario. The total installed electricity capacity is 3 % higher for the Biomass scenario and 1 % lower for the boiler scenario. This can be explained in context with the installed heat capacity which is presented in the following.

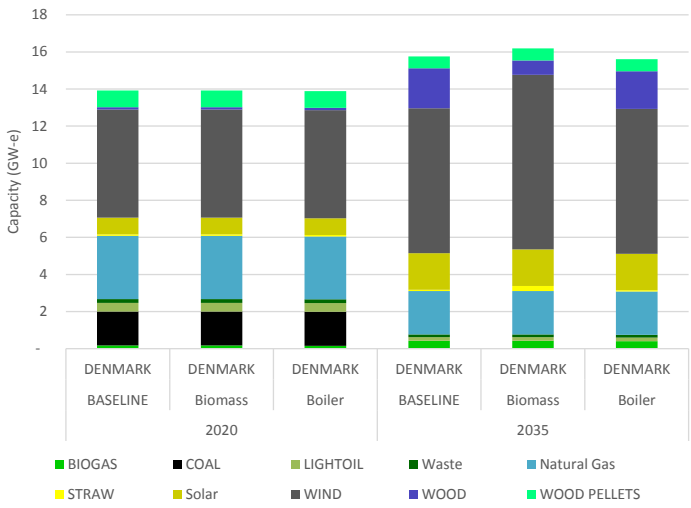

Figure 8.1: Total power capacity, Denmark

The investments in stand-alone heat production capacity is seen in fig 8.3. The main heat capacity investments in 2020 is in heat pumps with 1400 MW, and Natural gas boilers with 240 MW for both the baseline scenario and the Biomass scenario. In the boiler scenario where investments in biomass boilers are allowed both Heat pumps and Natural gas boilers are 100 MW. This capacity is substituted with biogas boilers with a total installed capacity of 120 MW and straw boilers with 190 MW. In the boiler scenario the total newly installed heat capacity is 1 % higher than in the other two scenarios.
For 2035 the main constituents of newly installed capacity is heat pumps, solar heat and waste boilers [1]. The installed solar heat capacity is relatively large compared to the delivered energy because of relatively few load hours, as seen in fig 8.6. The installed heat capacity in the biomass scenario is 30 % higher than the baseline scenario. The higher investments in heat capacity is caused by the biomass restriction that makes the system prefer more wind power in substitution of biomass CHP capacity. The increased heat capacity thus consists of heat pumps. In the Boiler scenario further biogas heat capacity (80 MW) is installed but especially straw (450 MW)is installed. The installed waste boilers does (700 MW) does not vary significantly between the scenarios in 2035. The total heat capacity can be observed in fig 8.4.
The District heating storage capacity is seen in fig 8.5. In 2020 there is no difference between scenarios with around 90 GWh thermal capacity installed. In 2035 even more storage capacity is installed. In the Boiler scenario the heat storage capacity is 12 % lower than in the baseline scenario, in the Biomass the heat storage need is 6 % higher which relates to the heat capacity increase in the biomass scenario and the capacity decrease in the boiler scenario.
In general is is noted that the limitation in biomass lowers the CHP capacity from biomass, increase the electricity use for heat production in heat pumps

[1] It is noted that the utilization of municipal waste changes from present day use where a high share is used in CHP plants

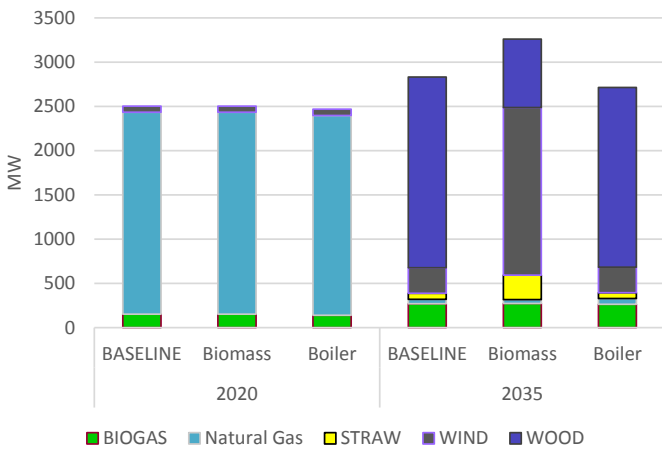

Figure 8.2: Endogenous Power capacity, Denmark

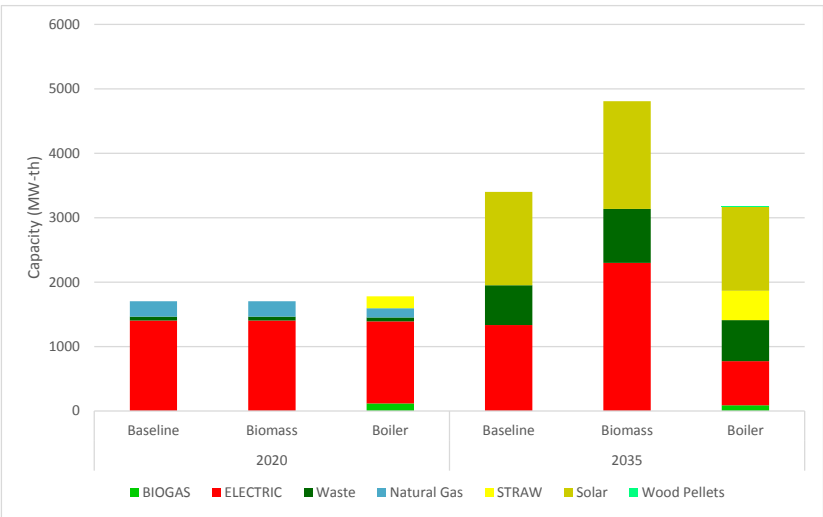

Figure 8.3: Endogenous stand-alone Heat capacity for Denmark

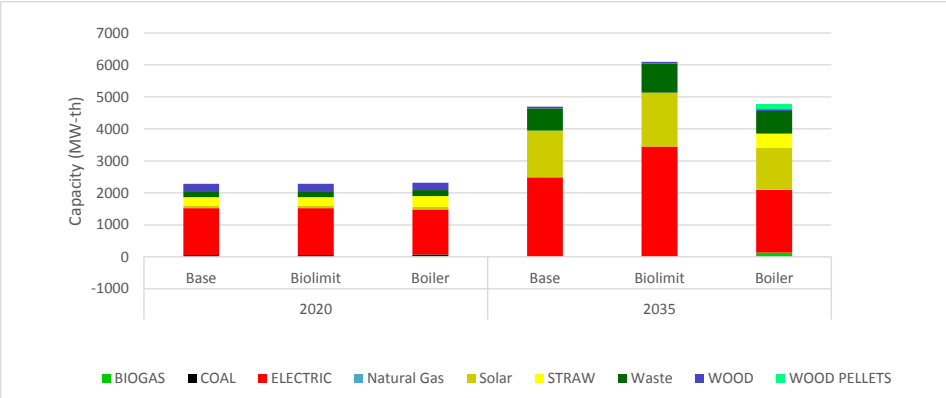

Figure 8.4: Total stand-alone heat capacity Denmark

Figure 8.5: Existing and endogenous heat storage capacity, Denmark

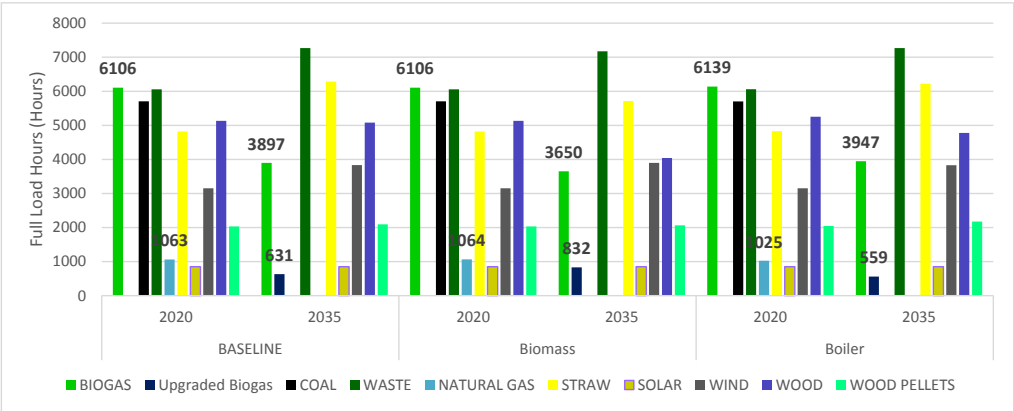

Figure 8.6: Full load hours for power capacity, Denmark

8.2 Fuel consumption and CO2 quota price

In figure 8.7 the total fuel consumption in all included countries in the baseline scenario can be observed. The total fuel consumption is decreasing from 2020 to 2035, due to increased efficiency on the production side and a reduced demand-side energy use, from e.g increased efficiency in housing isolation. The biggest changes in fuel consumption from 2020 to 2035 is the reduced use of coal and natural gas, and increase in wind power and waste. When observing the CO2 quota price in figure 8.8 it is seen that the decrease in fossil fuels is pushed down because if the increased quota price. The decrease is not forced by the CO2 emission constraint as which is apparent as the marginal value of emitting CO2 is 0 EUR14 in 2035.

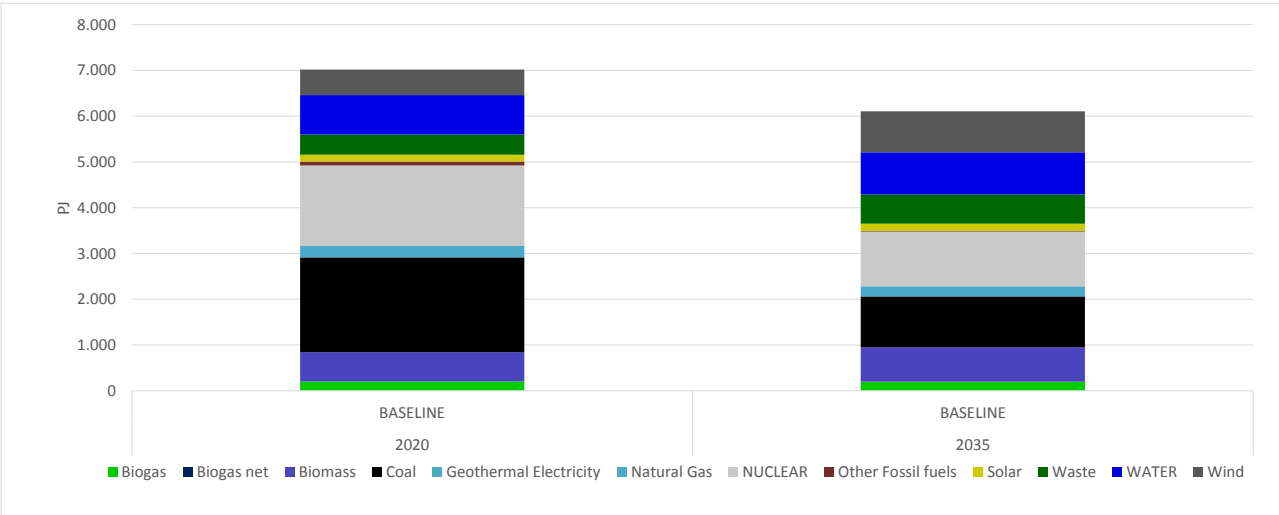

Figure 8.7: Total fuel use

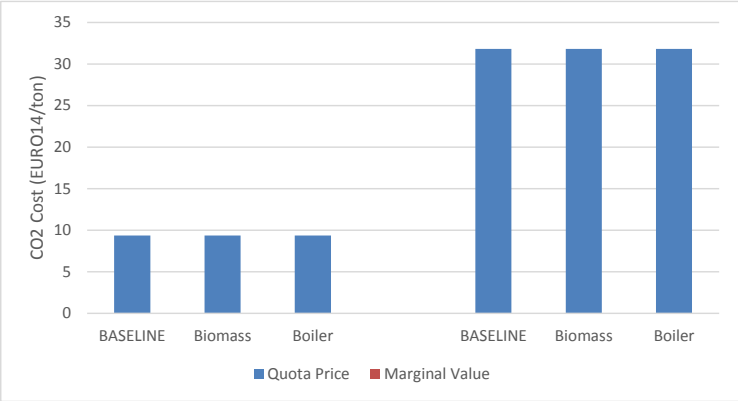

Figure 8.8: CO2 quota price

8.3 Biogas production and use

In this section the biogas production and further use is presented, to gain insights on where biogas and upgraded gas is beneficial for the energy system.
Regarding the total production and its further use of biogas between scenarios, an overview is given in figure 8.9. In 2020 only a small fraction between 2-3 % is upgraded for all scenarios, as seen on the figure. In 2035, 21% of the biogas is upgraded in 2035 for both the baseline and the boiler scenario. For the biomass scenario the ratio of upgraded biogas is increased, such that a total of 23,5 % is upgraded. The upgrading is only taking place with the amine scrubber technology. As one third of the biogas is upgraded, the potential system benefits of upgrading with methanation and a SOEC does not outweigh their high investment and operational costs.

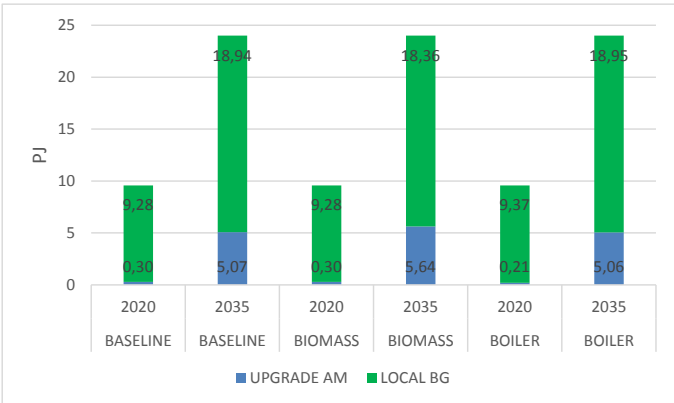

Figure 8.9: Biogas and Upgraded biogas production, Denmark

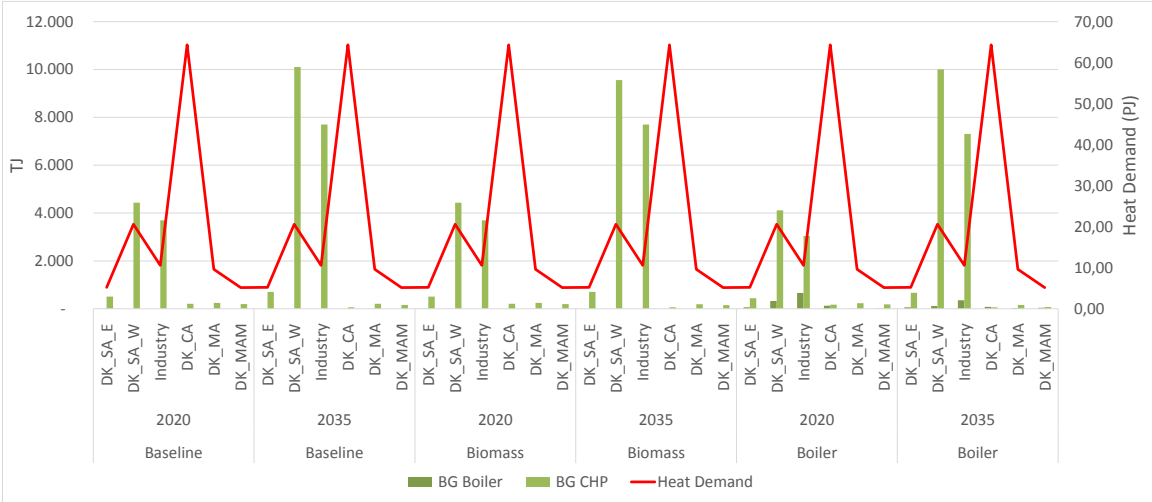

Figure 8.10: Technology specific biogas use in Danish DH areas, with annual heat demand

The use of biogas on a DH area level can be observed in figure 8.10. The DH area names is explained in the notation explanation and in appendix A.4. It is noted that there is no difference between the total biogas use for the baseline and biomass scenario for 2020. The utilization of biogas in 2020 is primarily based on Biogas CHP (existing and new investments) with a small amount used on existing biogas boilers in the small areas of eastern Denmark for the baseline and biomass scenario. New biogas boilers are not allowed in the baseline and biomass scenario, complying with the rules of Projektgodkendelse as mentioned in section 7.2. For 2035 the biogas use in the DH areas show no major differences in the total biogas use between the baseline scenario and the boiler scenario. In the biomass scenario, with the increased amount of upgraded biogas, a decrease in biogas use (5 %) is observed in the small areas in western Denmark, i.e the extra upgraded biogas is produced in these areas. In figure 8.11 the biogas use by technology in the boiler scenario is shown for the different DH areas. The reader should note that some of the bars in the chart are reaching outside the chart. For the boiler scenario in 2020, 13 % of the biogas is used on boilers, while 3.5 % is used on boilers in 2035, for the total BG use in the DH areas. In the central areas the highest use of biogas in boilers, relative to the total biogas use, with 40 % in 2020 and 55% in 2035. The decline in total use of biogas in boilers from 2020 to 2035 stems primarily from the decline in boiler use in the DK_W_SA and Industry DH areas.

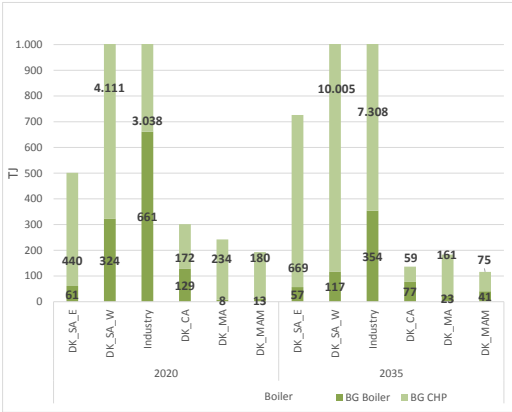

Figure 8.11: Technology specific biogas usage in Danish DH areas for Boiler scenario

The specific use of upgraded biogas on technology types for the different DH area types can be observed in figure 8.12. In 2020 the use of upgraded use of biogas is used only on (existing) CHP back pressure NG technologies in the MA,MAM, SA areas for all scenarios. In 2035 the majority of the upgraded biogas is used on new CHP extraction capacity in central DH areas. This trend is the unchanged for all scenarios. The extraction technologies are only available in the central DH areas. A small proportion (between 0.4 and 0.6 %) of the upgraded gas is used on the remaining existing back-pressure CHP that has not been phased out in the small SA DH areas [2]. The increase in use of upgraded biogas in the biomass scenario is on the CHP extraction capacity.
The full load hours (FLH) for technologies using biogas and upgraded biogas fuel to produce electricity and heat is significantly different. As seen in figure 8.6, the biogas FLH for 2020 are around 6100 FLH for all scenarios. For 2035 the FLH are reduced to 3650-4000 to FLH between scenarios. For upgraded biogas the FLH hours in 2020 is 1000 hours (see NG FLH). In 2035 the FLH on Upgraded biogas is decreased to 630 FLH for the baseline scenario. For the biomass scenario the FLH are 830, for the boiler scenario it is 560 FLH.

[2]Exogenous capacity is phased out at a rate of 5% per year, in the model

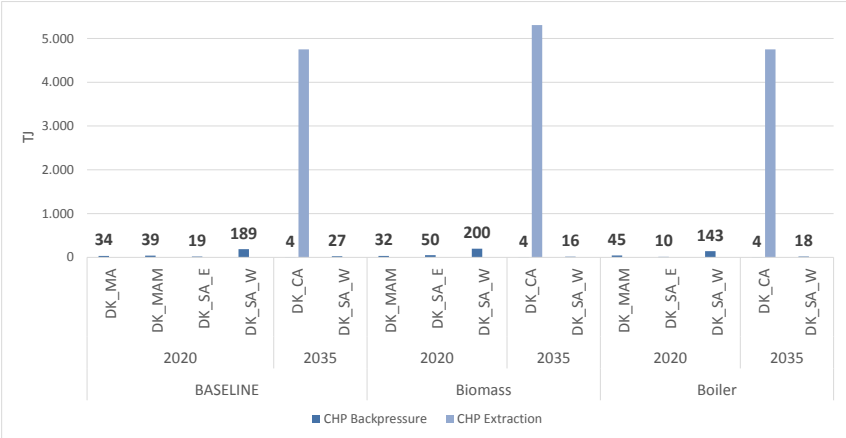

Figure 8.12: Upgraded biogas usage on model DH areas in Denmark

In table 8.1 an overview over where and how much biogas from energy crops are used in the different DH areas, and where the biogas is upgraded in the baseline scenario. It is observed that the the industry area has the largest ratio of biogas from energy crops, producing 3,2 times more biogas from energy crops than the biogas from manure potential. Furthermore no biogas is upgraded in the industry DH areas. The small areas in western Denmark has the second largest ratio with 0.5. Except for small DH areas in eastern Denmark there is some biogas from energy crops produced in each DH area type which indicates that the biogas production regulation is beneficial to all DH areas. The high amount of biogas from energy crops that is used in the industrial areas can be explained by a different demand profile and the technology investment opportunities for the areas. This will be touched upon in the following section.

Table 8.1: Biogas production and upgraded biogas production in Danish DH areas in 2035

	DK_CA	DK_MA	Industry	DK_MAM	DK_SA_E	DK_SA_W
BGCROP/BGMAN Ratio	0,13	0,05	3,20	0,03	0,00	0,48
BGupg / BGtot Ratio	0,92	0,56	0,00	0,63	0,34	0,25

Table 8.2: FLH for biogas production with EC in Danish DH areas

DK_CA	DK_MA	Industry	DK_MAM	DK_E_SA	DK_SA_W
7720	6490	7060	6660	0	6480

The ratio of upgraded biogas to the total biogas production is highest in the central DH areas, lowest in the small areas without waste (below 35 %) and for areas with waste the amount of biogas upgraded is around 60 %. This gives a picture of where the biogas is most valuable and is explained among other things by the technology options for investments in the different areas. This will be mentioned in the following section. The relative amount of

biogas upgraded from each DH area is seen in figure 8.13, it can be seen that the largest amount of upgrading comes from the small areas in Western Denmark, followed by the central areas, the small areas in Eastern Denmark, and an equal amount from the waste DH areas. This pattern is unchanged between scenarios. For the biomass scenario where the amount of upgraded biogas is higher than the baseline scenario, the relative amount of upgraded biogas for each DH area remains constant. In the boiler scenario, a very small amount of upgrading takes place in the industry DH areas.

In table 5.3 the FLH for the biogas production with EC in the DH areas. The FLH value gives an indication of how the biogas production with EC is used in the DH areas. It is observed that for the small DH areas of western Denmark the FLH are

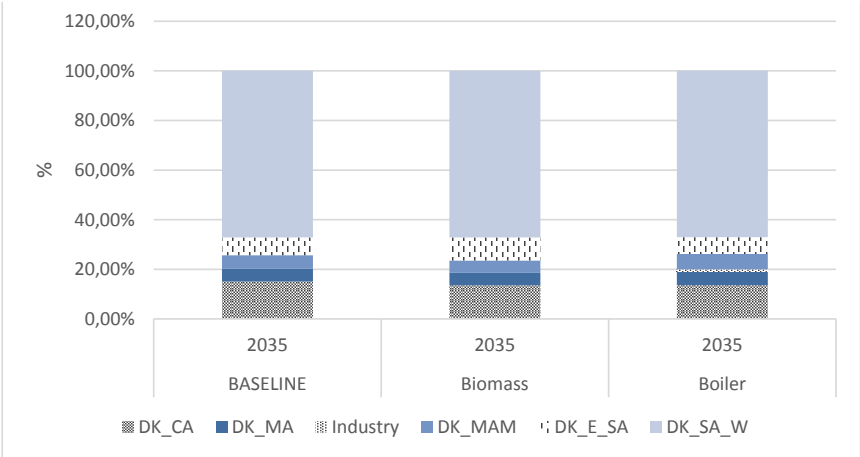

Figure 8.13: Relative amount of Upgraded biogas production in Danish DH areas

8.4 Electricity and heat production

The electricity production by fuel for the countries included in the model can be observed in figure 8.14. The electricity production is shown as the relative production for year 2035 for the baseline scenario. On the figure it can be observed that the biogas use is higher than the use of upgraded biogas, even though the capacity for using upgraded biogas is higher than the biogas eletricy capacity. This can be explained by the utilization of the capacity by the electricity and heat system. In figure 8.6 it is observed that the FLH of biogas capacity in 2035 is considerably higher than the upgraded biogas capacity. In figure 8.14 the differences in the electricity production between countries it reveals how differently the electricity production is between countries; Norway has a very large share of electricity by water, while Finland has large electricity production prom nuclear power.

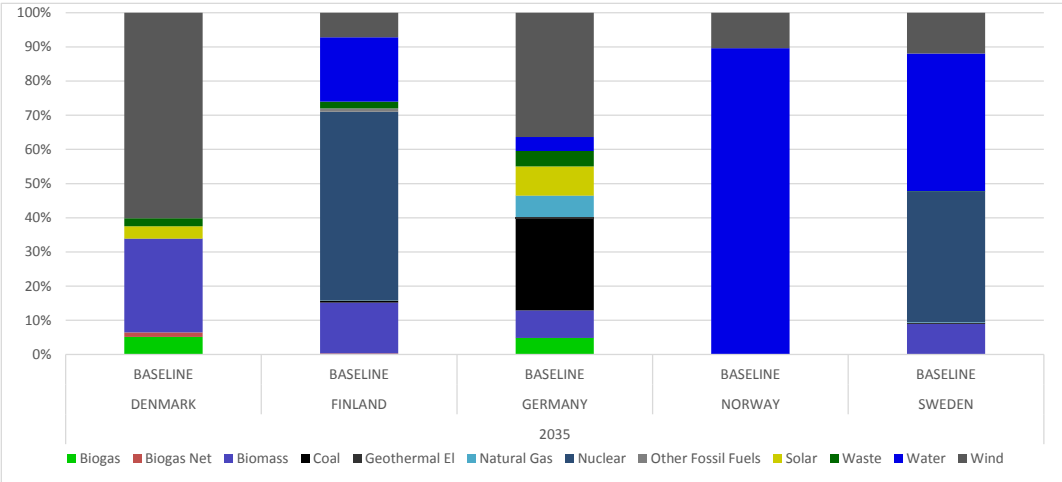

Figure 8.14: Power generation, relative

The DH heat production in Denmark by area and technology type is presented in figures 8.15 - 8.17, to describe some of the drivers for the differences in biogas and upgraded biogas use. First directing focus on the upgraded biogas use. As observed in the previous section upgraded biogas is only used in central DH areas. The heat production in the central areas can be seen in figure 8.15. In 2035 for the baseline scenario the central areas have the largest part of the heat demand covered by covered by wood CHP, waste with both CHP and boiler, and surplus heat, respectively [3]. In the biomass scenario the wood resource is limited in 2035 and the heating demand is substituted with pure heat from waste boilers, heat pumps, upgraded biogas CHP, and straw CHP. For the boiler scenario, there are no apparent changes in the heat production for the central areas.

[3]Surplus heat is in the model in [22] available from plants producing bio fuels for the transport sector

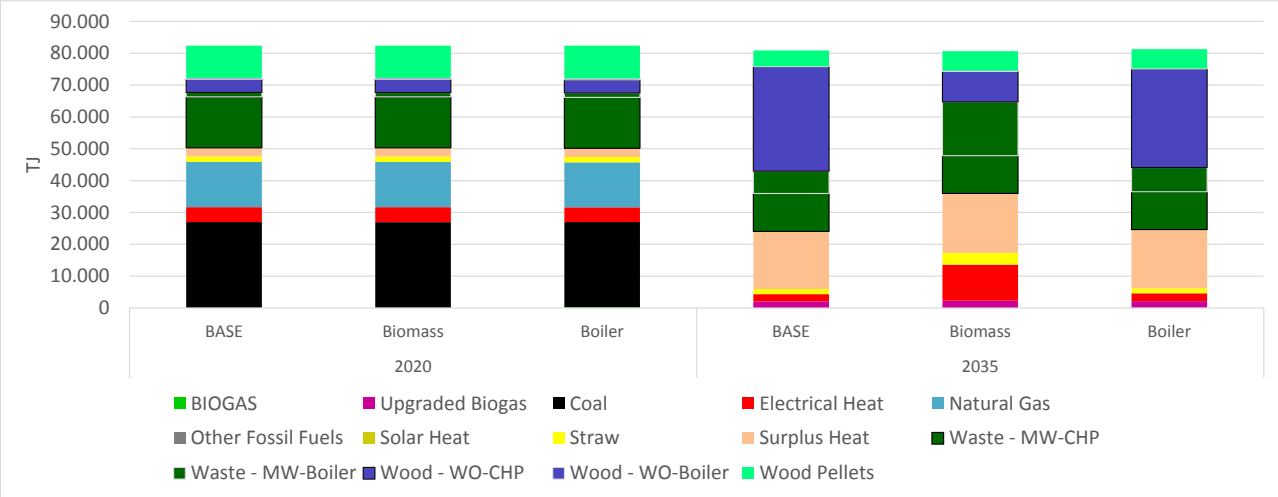

Figure 8.15: Heat generation, Central Areas

Focusing on the biogas use, the areas where most biogas is utilized is in the industrial areas and the small areas of Western Denmark. The figures 8.16 and 8.17 show the heat production in the industry and small heat areas, respectively. In 2035 the industry area covers its heat demand with biogas CHP, electrical heat from heat pumps and some wood CHP. In the biomass scenario the wood use in the industry area is reduced to 0 and is substituted with heat pumps. The wood is allocated to technologies with better efficiencies, e.g in the central areas as seen in fig 8.15. In the boiler scenario the heat covered by wood and heatpumps, are completely substituted with straw boilers. This decrease in heatpumps between the baseline and boiler scenario is larger than the general trend, because the heatpumps available for investment in the industry area are more expensive than the large DH heat pumps installed in the DH areas. This in turn makes straw boilers and biogas feasible in the industry areas. In the small areas in the baseline scenario for 2035 the heat demand is mainly covered by DH heat pumps, biogas CHP and solar heat and a small amount of surplus heat. For the biomass scenario a decrease in biogas is observed, which is substituted by solar heat. In the Boiler scenario a part of the heat pump capacity is substituted by straw boilers. Comparing this result with the Industry area Boiler scenario, the DH heat pumps available for investment in the small areas are more cost efficient than the one in the industry area.

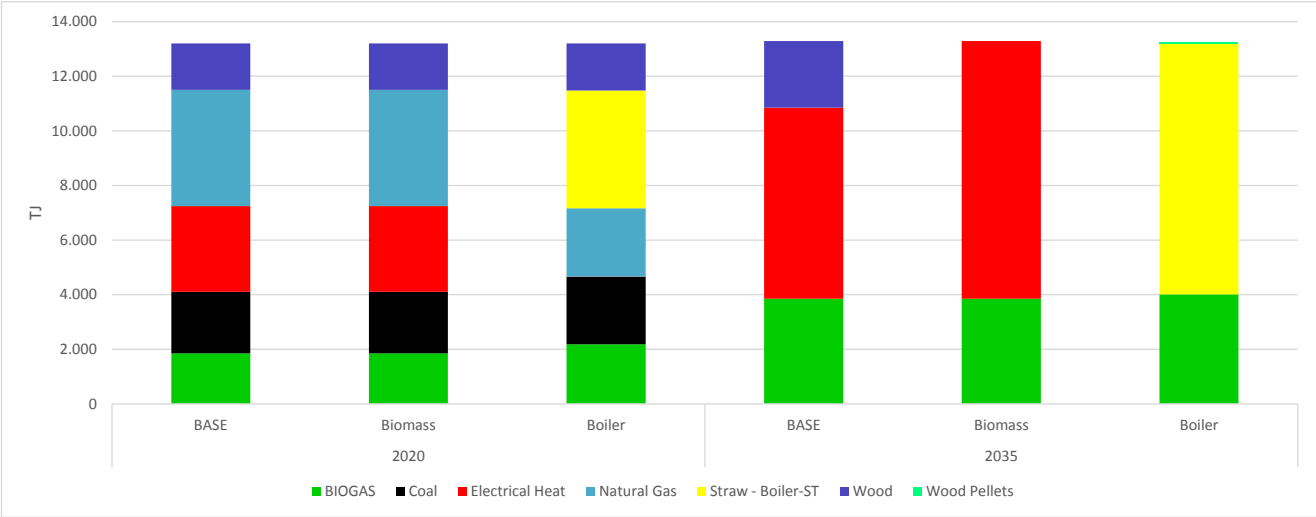

Figure 8.16: Heat generation, Industrial Areas

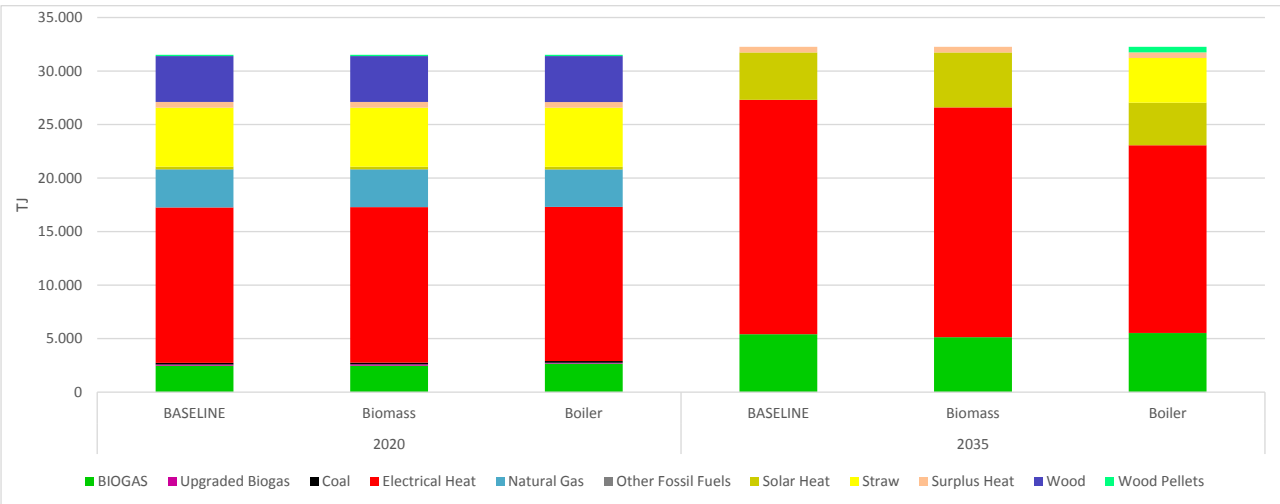

Figure 8.17: Heat generation, Small Areas

8.5 System Costs

In figure 8.18 the total annualised system costs for Denmark is displayed for the different scenarios in 2020 and 2035. Comparing the baseline scenario and the biomass scenario, it is noted that the fuel costs are substantially lower (40 %) in the biomass scenario. As seen in the previous sections the lower biomass use leads to an increase in wind power and electrical heating, that does not incur fuel costs. In total the technologies substituting the wood based CHP and boilers increase the annualised capital costs (6 %), variable and fixed o&m costs(1%, 4 %). The CO_2 emissions and their induced costs does not change substantially between baseline and biomass scenarios in Denmark. The costs related to investments in electricity transmission capacity (not shown on the figure) are the same for all scenarios, as maximum transmission investment possibilities are utilized for all scenarios. For the boiler scenario the total of capital costs and operational costs are lower than the baseline scenario. The boilers have lower investment costs and fixed O&M costs than the baseline scenario but slightly higher fuel and variable O&M costs. The total annualised system costs for both 2020 and 2035 for the whole energy system (all countries) can be observed in table 8.3. The Biomass scenario increase the total system costs, because of the fuel limitation for wood in the Danish region, while the boiler scenario has a lower system costs as the scenario opens up for allowed capacities that is cheaper for the system to utilize.

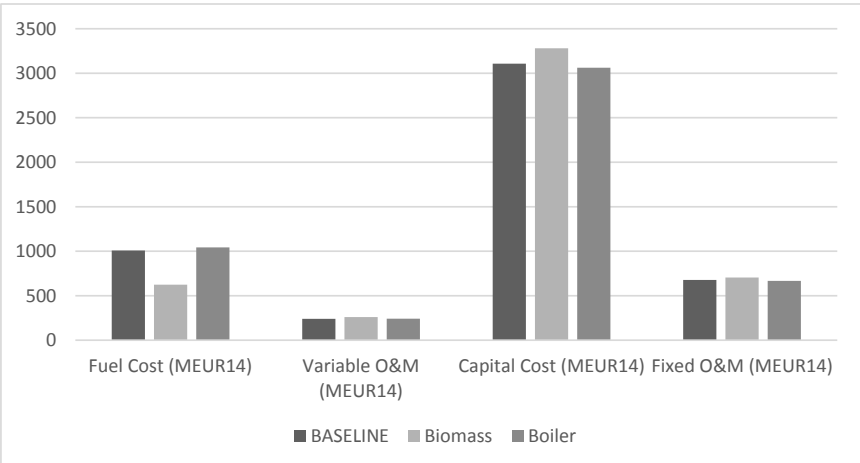

Figure 8.18: System costs for Denmark

Table 8.3: Total system costs for 2020 and 2035 for scenarios

	Base	Biomass	Boiler
Total Costs MEUR14	81630	81725	80405
Relative costs %	100	+0,12	-0,15

8.6 Changes in electricity production in boiler scenario and CO_2 emissions

The change in electricity production in the included countries resulting from the increased heat production with biomass boilers, in the boiler scenario can be observed in figure 8.19. The results can be used to asses how the changes between scenario affect the production which is especially important for the boiler scenario as discussed in section 7.2. The condensing electricity production is the production from pure condensing plants and extraction plants in condensing mode. For the biomass scenario in 2035, the total condensing production for all countries decrease with 300 GWh. Sweden sees an increase from Wood extraction plant in condensing mode 500 GWh, but the decrease in Denmark and Germany, lowers the total condensing production for the boiler scenario. The electricity production from CHP plants are decreased with 850 GWh total. The changes in production pattern yields lower CO_2 emissions than the baseline scenario, as seen in table 8.1. In 2020 the CO_2 emissions are even lower because of higher displacement of condensing production (not shown in figure) as seen in table 8.4. For the biomass scenario an increase in condensing production is observed for 2035, where the wood fuel limitation starts to affect the optimal solution. The result is an increase in CO_2 in 2035.

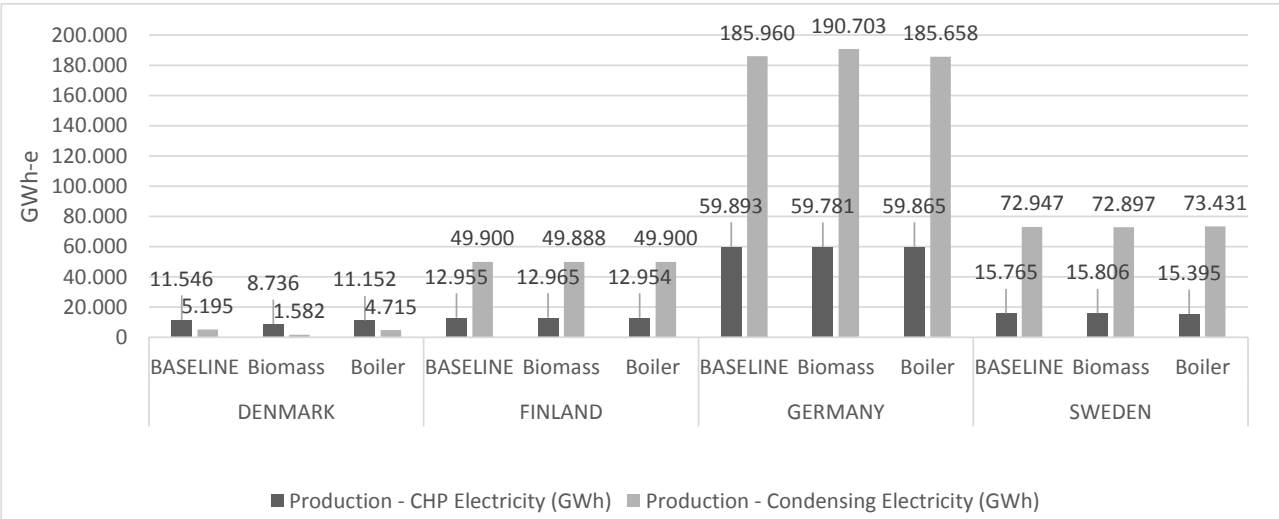

Figure 8.19: Electricity from CHP Production and Condensing Production

Table 8.4: CO_2 emissions for the total system in 2020 and 2035

CO_2 Emissions (kilotons)	Base	Biomass	Boiler
2020	241.736	241.736	240.832
2035	144.869	147.182	144.799

8.7 Sensitivity analysis

A sensitivity analysis is carried out for selected relevant parameters related to the use of biogas and upgraded biogas. The parameters chosen and the sensitivity range, are listed below.

- Revenue of upgraded Gas to the system: +25 %,+50 %
- Investment costs and operational costs of the Amine scrubber technology: +25 %, -25 %

The costs of the amine scrubber technology is in the scenarios is based on large scale advantages. Increasing the costs of the amine scrubber in the sensitivity analysis, reflects that some upgrading facilities likely will be built in a smaller scale, which increase the cost of upgrading biogas. As the amine scrubber technology is new on the market there is still room for the technology to develop and thus decreasing costs. This is also reflected in the sensitivity analysis. Varying the revenue on upgraded biogas reflects that the upgraded biogas has a higher value to society than is reflected in the CO_2 quota price.
Furthermore it is tested how large a reduction in the costs of upgrading with methanation and SOEC should be obtained, before it becomes feasible for the system to use the technologies.

Results of the Sensitivity Analysis The results of the sensitivity analysis can be observed in table 8.5. The results are presented as the percentage of upgraded biogas in the baseline scenario when varying the parameters described in the previous section. The general results on biogas use is confirmed for the chosen parameters in the sensitivity analysis.

Table 8.5: Sensitivity analysis results, upgraded biogas percentage

	CAPEX AM+25	CAPEXAM-25	Upg.BG Revenue+25	Upg BG Revenue+50	Baseline
Biogas Upgraded (%)	14,9	22,8	23,3	24,8	21,1

For the methanator with the SOEC technology it was found that a reduction in CAPEX and OPEX between 70-80% is needed for the technologies to compete with the amine scrubber towards 2035. This implies that unless a big reduction in technology costs occurs, there is little prospect for methanator and SOEC technology market shares in the electricity and heat sector in a time horizon of the next 20 years.

9

Discussion & Future Work

Discussion of scenario results In the Boiler scenario, it was observed that a small amount of the biogas was utilized in biogas boilers both in 2020 (13 % and 2035 (3,5 %) when allowing for the use of biomass on new boilers. However it was feasible for the system to increase the investments in straw and wood boilers. It was found that the increase in generation of heat from biomass boilers in the boiler scenario does not give rise to a total increase in condensing electricity production and CO_2 emissions. Furthermore the total costs of the modelled energy system is lowered when allowing biomass boilers. No significant changes in the use of upgraded biogas was seen comparing with the baseline scenario. The changes in natural gas use from allowing biomass boilers, was observed to be 2 PJ in 2020 which is a 4.5 % reduction of the yearly NG use. This reduction affects the payback time for the natural gas networks (if the tax framework is not changed).
In the Biomass scenario the restriction in wood in the Danish region caused an increased electrification of the Danish energy system with wind power, which in turn gave rise to an increase in the use of upgraded biogas from 21 % in the baseline scenario to 23,5% in 2035. The upgraded biogas is in 2035 utilized on cost efficient extraction technology in the central DH areas with full load hours below 1000 hours.
Looking at the use of biogas from energy crops, production was all DH areas, which leads to believe that seasonal regulation is efficient in all DH areas types. In the small DH areas the lowest full load hours for the biogas production facility was observed, which indicates that here the biggest value of seasonal regulation is achieved. For the Industry area, which utilized most biogas compared to it's heat demand, a higher amount of full load hours for the capacity was observed. This could imply that the value of the energy crops for the Industry areas is less ascribed to the seasonal regulation ability of the biogas production facility, and more that biogas CHP is attractive when the least expensive heat production units are small heat pumps and straw boilers.

Geographical distribution of Manure In the thesis the largest part of the biomass potential from MAN is allocated to the small areas of western Denmark and the industrial areas, as described in section 7.1. The biomass distribution between DH areas and the industry in a municipality was done rather crude. As such a more sophisticated approach could be taken where the distribution of biomass potential incorporated geographical data for the location of manure potentials in a DH-area. This would also give the opportunity to

include distances from biogas production units to potential users; from industry customers to DH technologies.

Results compared with other studies In the report from Ea [22] the amount of upgraded biogas 2035 is approximately 50 %. This is a relatively large difference from the results obtained 21-23,5% obtained in this study. In the Ea report, the upgraded biogas is for the major part used in central areas, but there is also a use of upgraded biogas in small areas and medium areas, which was not observed in this study. In the recent report from Energistyrelsen [54],50 % of the biogas potential in 2035 in upgraded with methanation, while the remaining 50 % is upgraded by regular upgrading technologies, such as amine- or water-scrubbers. The report uses back-casting to establish scenarios and the share of upgrading is thus chosen exogenously. One of the reasons for choosing a high share of upgrading by methanation is the increased fuel production, that increases the overall supply of energy security by producing fuel for peak producing gas technologies, that can assist an energy system that is electrified with wind power. The sensitivity analysis showed that the costs (capex and opex) of the methanator with SOEC technologies should be approximately 70-80 % lower in order for them to compete with the amine scrubber in 2035. Setting up a scenario with the data from the report from Energistyrelsen and force the model to invest in methanation with SOEC, and comparing this with a scenario where upgrading only is done with regular upgrading technologies. The extra costs would then be a step to pricing the term energy security.

Biogas Externalities With the included externalities in this analysis, it was seen that biogas is not feasible for the energy system. A follow up study it would be interesting to include externalities and/or determine how much lower the biogas should cost if it were to be profitable to the system.

Analysis with current tax and subsidy framework As this report contributes with a socio economic analysis the relevant further work would be to analyse the technologies in a private economic context. The tax and subsidy regulation are key factors for which technologies will in fact be installed. The subsequent analysis could shine a light on whether the existing tax and subsidy framework incentivize the investments found to be socio economically optimal. In the report from Ea [22] the analysis showed that the current tax and subsidy framework leads to higher investments in upgraded gas, than in the scenarios without tax and subsidies.

Model Linearity The model applied in the analysis is linear, which means that start-up, shut-down costs, part load efficiencies and minimum load requirements are not included. The operational economy of starting and stopping power plants can have a large impact on the value of technologies which can provide with up- and down-regulation from a demand side perspective such as upgrading technologies. As such the benefits of upgrading technologies could be understated in this analysis. In the validation section it was observed that the methanator is running for long periods on minimum capacity. Including start-up, and shut-down costs could possibly alter the cost of operating the methanator. The dynamic properties and costs of running the methanator in start,stop mode should be assessed, as it was seen in the verification section 6 that the methanator is running on minimum capacity for long time periods. This could be interesting to follow up in a future study. It should be mentioned that the solution-time would be drastically increased, because a integer-model would have to be used for optimization.

As mentioned in the Energy system Tool section 3 the model has perfect foresight for all future demands and prices. As a consequence knowing demands and outages of all technologies, the model does not have the ability to evaluate the extra need for active power balancing in connection with both energy and wind forecast errors. In the model this can be accomodated with ad-hoc requirements, such as a minimum need for base load capacity as to ensure that enough frequency stabilizing capacity is in operation. Furthermore the need for voltage control and reactive power control equipment in a power system with a high percentage of wind power is not estimated, which in turn could underestimate their system integration costs.

Temporal resolution of the Model The optimization of operation of, and investment in energy technologies was in the analysis not performed at the highest temporal resolution for both seasons "S" and time steps "t". For the season resolution investment optimization was set to 12 seasons. For time steps in each seasons the time steps was aggregated into 6 time steps. In the verification section 6 and appendix B the time aggregation is explained. Ideally the model should be run with the full time scale solution to verify whether the aggregations in both seasons and time steps affects the results. The method of aggregation could underestimates peak load capacity and the need for storages, compared to selecting few weeks with high variability in both demand and wind production. The trade-off's and effects of how the optimal solver solution depends on using either the time aggregation method versus selecting few seasons with full time step resolution, compared to using full time scale resolution, is a topic that could addressed in another study. The study would be beneficial for all users of the model.

Seasonal Regulation As was seen in the validation section, the biogas production for the specific case area was characterized by ramping up production for some time steps even though heat demand is low, with but biogas engines producing a high share of electricity. For biogas producers it would be difficult to plan for the variations for biogas need, as biogas producers have no market price signal to react to. By installing a larger biogas storage and having a slightly higher base production the variations in biogas production during the low heat demand season could be circumvented. Furthermore, practical knowledge of operation with the biomass fraction used for seasonal regulation of biogas production is not known.

Including additional demand for green gasses In relation to further analysis, it would be relevant to include additional competing demand technologies for green gasses, such as vehicles using upgraded biogas. In order for upgraded gas to be utilized on vehicles a pressure of 250 Bar is needed, which would incur extra costs for compression at the upgrading facility. The representation of this demand could alter the optimal investments for upgrading technologies, depending on the retail price of the upgraded gas and the amount. The competition could also lead to more biogas being upgraded with hydrogen and methanation because of the increased fuel demand. Regarding hydrogen production, the transport sector could further be represented by including a demand for hydrogen production used in the fuel production of bio fuels. This has e.g been done in the recent report from the DEA [54] which analyse pathways to a power system free of fossil fuels in the long term perspective of 2050, by creating 5 scenarios with back-casting procedure. In the "Wind" and "Brint" scenarios in 2035, 4-8.5 PJ hydrogen, respectively, is used in the process of producing bio-fuels such as bio-diesel and bio-kerosene.

Additional injection demand for upgraded biogas use in the electricity and heat sector Furthermore the possibility of injecting the upgraded biogas into the distribution network could be relevant to include for further analysis. In [65] it is reported that an actual injection into the distribution network is a cheaper option than injection of upgraded gas into the transmission network. The lower costs are associated with a lower capital cost for the compressor and connection equipment dimensions and lower operational costs due to lower compressor energy needs. However the advantage to use the upgraded gas in other areas than the distribution network is lost and as a consequence, the gas cannot be directed to technologies with high efficiencies in other DH areas. Furthermore the flexibility of using the natural gas storages is lost. The results obtained shows that upgraded biogas is used primarily in central areas, but the upgrading takes place in all types of DH areas except the industry areas. Injection to the local NG network could be relevant for the central areas. Including this option, the model would need balance equations for the local NG networks.

10

Conclusion

In this thesis, a mathematical model add-on that optimizes the investments in and production and use of biogas for a DH area, has successfully been integrated to the version of the electricity and heat optimization model, developed by Ea with the modelling tool Balmorel. The add-on is based on the mathematical model developed by Ea. For the add-on the possibility to upgrade biogas with either an amine scrubber or the combination of a methanator and a SOEC, has been included. Furthermore, the geographical distribution of manure on a municipal level was implemented to the aggregated DH areas used in the Ea model of the electricity and heat sector.
3 scenarios was constructed that outlines coherent possible developments in the Danish electricity and heat sector that can influence the biogas production and use in Denmark, towards 2035. An analysis with the model add-on for the developed scenarios was carried out to answer the thesis research questions, which are reproduced below.

- Which investments in Green gas technologies will be beneficial towards 2035 from a socio economic perspective?
  - To which extent is it feasible to upgrade biogas to natural gas quality, in preference to using it locally?
  - Will upgrading with methanation with hydrogen provided by SOEC's be feasible in a future energy system with limited biomass availability?

The main findings of the baseline scenario is that it is feasible for 3 % of the biogas to be upgraded to NG quality in 2020 and 21 % in 2035. The biogas production from biomass that can be seasonally regulated is primarily used in small DH areas and in industry DH areas, as represented in the electricity and heat model, in CHP biogas engines with 6100 FLH in 2020 and 3900 FLH in 2035. The upgraded biogas is used in the central DH areas, represented in the model, in CHP extraction technologies with 630 FLH in 2035. When allowing for investments of biomass boilers in DH areas with natural gas production, as done in the boiler scenario, there is no change in the share of upgraded biogas, and only a small amount of the biogas is used in biogas boilers. In the biomass scenario, the allowed import of biomass is reduced to 100 % of domestic resources in 2020 and 0 % in 2035. For 2020 there is no change in the share of upgraded biogas compared to the baseline scenario.

In 2035 the share of upgraded biogas is increased to 23,5 % with 830 FLH, as a result of an increased need for peak capacity, driven by increased investments in wind turbine capacity. The technologies methanation and SOEC are not feasible for the energy system in towards 2035 in all scenarios due to high investment and operational costs. It was found that a cost reduction between 70-80 % is necessary for the technologies to be competitive with the amine scrubber technology in 2035.

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Part I

Appendix

A

DATA

A.1 Biogas

Table A.1: Methane yield by full digestion of substrates, from [22]

Substrate	CH_4(Nm^3/kg VS)	CH_4 (% of VS LHV)
Fat	0.96	70
Protein	0.51	64
Carbohydrate	0.42	50
Energy content CH_4	35,89 MJ/Nm^3	

Anaerobic Digestion

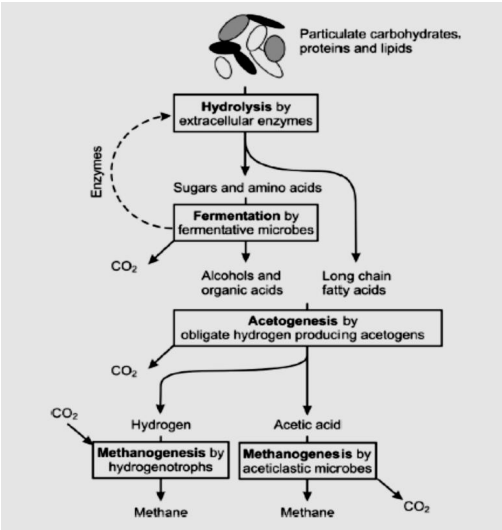

Figure A.1: Steps of Anaerobic Digestion, from [66]

The AD process steps can be observed in figure A.1.

Table A.2: Biogas production facility Investment and O&M costs , from [22]

Basic biogas facility costs	Investment EURO14/ton	O&M Fixed EURO14/ton
	42.4	3.4
Additional costs dependent on biomass input		O&M Variable EURO14/ton
Deep Litter	20.9	7.5
Solid Manure	17.4	6.7
Liquid Manure	0	0
Straw	57.7	15.4
Late Crops	13.4	6.7
Natural Areas (Grasses)	40.2	12
Buffer Zones (Grasses)	13.4	6.7
Ditch Borders(Grasses)	13.4	6.7
Garden-park Waste	57.7	15.4
Aquatic biomass	23.4	7.5
Organic Household Waste	6.7	7.5
Organic Industrial Waste	0	5.1
Energy Corn	6.7	2.4
Energy Beets	6.7	2.4
Grass-clover	6.7	2.4
Beet Tops Silage	6.7	2.4

Low Pressure Biogas Pipes The investment cost depends on the diameter of the pipes and necessary number of fans and compressors. The cost of investment is in EA taken from

a Danish project in the Ringkøbing-Skjern area where a low pressure biogas net is being established. The operational costs for biogas pipe comes from the electricity use in fans and compressors and are set to 2 % of the investment cost. The lifetime is 20 years. The costs can be seen in table A.3.

Table A.3: Low pressure Biogas Pipe, from [22]

Low Pressure Biogas Pipe	Value
Investment	120800 (EURO14/km)
O&M	2400 (EURO14/km/year)
Lifetime	20 (years)

Methane Yield The methane yields from the different biomass fractions is calculated in a report from Ea [22] which base their numbers from AgroTech [1]. In the Ea report the methane yield for straw and organic industrial waste has been adjusted. The yield is based on the VS parameter and the assumption that serial AD is used for production of the biogas for maximum yield. The VS values for various biomass fractions and the resulting methane yield can be observed in A.4.

Table A.4: Methane Yield for serial AD Process, from [22]

Biogas production	Nm^3 CH_4 per ton biomass	Nm^3 CH_4 per ton VS
Manure	11.6	241
Deep litter	55.0	245
Solid Manure	40.1	231
Liquid Manure	4.4	250
Straw	222.1	275
Late Crops	24.8	275
Natural Areas(Grasses)	143.5	277
Buffer Zones(Grasses)	59.5	265
Ditch Borders(Grasses)	55.2	245
Garden-park Waste	47.3	175
Aquatic Biomass	28.3	210
Organic Household Waste	106.3	420
Organic Industrial Waste	198.4	250
Energy Corn	100.0	351
Energy Beets	75.6	398
Grass-clover	40.6	301
Beet Tops Silage	33.7	299

Biomass input distribution and Biogas plant process heat Biogas can be produced from two different facilities that has a different distribution of biomass input. One facility is mainly based on manure (MAN) and the other is mainly based on energy crops (EC). The input distribution can bes seen in table A.6. Process heat with a straw boiler and flaring for

both facilities are accounted for in table A.5. The gross and net methane production can be seen in A.6 and A.5.

Table A.5: Gas flaring and process heat, from [22]

Percentage of gross biogas production	MAN	EC
Gas flaring	1 (%)	1 (%)
Process heat (straw heat boiler)	11 (%)	2.6(%)
Net Biomass Use(corrected for flaring)	5.23(ton/MWh)	1.24(ton/MWh)

Table A.6: Distribution of biomass input for plant configuration types, from [22]

	Distribution for Plant configuration (%)	
Biomass type	MAN	EC
Manure	0.872	0
Deep Litter	0.102	0
Solid Manure	0.003	0
Liquid Manure	0	0
Straw	0	0.170
Late Crops	0	0.141
Natural Areas(Grasses)	0	0.062
Buffer Zones(Grasses)	0	0.050
Ditch Borders(Grasses)	0	0.020
Garden-park Waste	0	0.051
Aquatic Biomass	0	0
Organic Household Waste	0.014	0
Organic Industrial Waste	0.010	0
Energy Corn	0	0.059
Energy Beets	0	0.070
Grass-clover	0	0.100
Beet Tops Silage	0	0.280
Gross Biomass use	5.22(ton/MWh)	1.24(ton/MWh)

Biomass cost The biomass prices is based on [22] which again is based on [1]. The prices is stated an the biogas facility thus including transportation. The prices can be observed in table A.7.

Table A.7: Purchase and transport cost of biomass, from [22]

Biomass Cost	Transport EURO14/ton	Purchase EURO14/ton
Manure	3.35	0
Deep litter	6.71	0
Solid Manure	6.71	0
Liquid Manure	6.71	0
Straw	0	67.31
Late Crops	0	19.32
Natural Areas(Grasses)	0	38.59
Buffer Zones(Grasses)	0	33.55
Ditch Borders(Grasses)	0	32.21
Garden-park Waste	0	6.04
Aquatic Biomass	0	3.02
Household	0	18.85
Organic Industrial Waste	0	40.26
Energy Corn	0	34.89
Energy Beets	0	36.91
Grass-clover	0	22.14
Beet Tops Silage	0	7.54
Process heat	EURO14/GJ	
Straw	8.96	

Biogas Plant Final Economical parameters The investment costs, O&M costs and final biomass costs for the biogas production facilities can be observed in table A.8. The investment costs include investment in biogas low pressure pipes and the additional investment costs ascribed to the distribution of input biomass. O&M costs are also including the extra cost for the input biomass composition.

Table A.8: Economical parameters for biogas production including gas pipes, from [22]

	MAN	EC
Investment (MEURO14/MW)	1.48	0.9
Variable O&M (EURO14/MWh)	27.43	13.92
Biomass (EURO14/MWh)	24.27	35.76

Biogas Storage Costs [22] base the costs of the gas storage on experience from the operation and maintenance of Hashøj biogas production facility. The costs can be seen in table A.9.

Table A.9: Gas storage costs and lifetime, from [22]

Gas Storage	
	Value
Investment	47.5 (EURO14/Nm^3 CH_4
O&M	0.35 (EURO14/Nm^3 CH_4 year)
Lifetime	10 (years)

Table A.10: Conversion factors between currencies and years

DKK14/EURO14	DKK11/EURO90	DKK14/EURO90
7.46	11.5	12.1

Table A.11: Lifetime adjustment by capital factor

Lifetime	Adjusted Lifetime	Annual Rate	Capital Factor adjustment
5	20	4%	3.05
10	20	4%	1.68

A.2 Upgrading technologies

Upgrading by removal of CO_2

Table A.13 shows the summarized economical findings for the amine upgrading facility and net injection

Table A.12: Characteristics for Upgrade Units by removal of CO_2. Values are from SGC in [43]

Upgrade Units	Characteristics	Value
PSA	Electricity consumption	0.2 kWh/Nm3 CH_4
		0.17 kWh/Nm3 (drying and final compression)
	Availability	96-98 %
	O&M (Annually Relative to Investment Cost)	1 %
	Recovery	Up to 98 % , but will increase investment cost
Organic Scrubber	Electricity consumption	0.25 kWh/Nm^3 CH_4 (500 Nm^3/h CH_4),
		0.2 kWh/Nm^3 CH_4 (>1000 Nm^3/h CH_4)
	Availability	96-98 %
	O&M (Annually Relative to Investment Cost)	2-3 %
	Recovery	>98.5%
	Methane concentration	99%
Membrane separation unit	Electricity consumption	0.2-0.3 kWh /Nm^3 CH_4
	Availability	> 95 %
	Service (Annually Relative to Investment Cost)	4 %
	Additional O&M for pretreatment steps	4 %
	Recovery	98-99 % (design ii), 99-99.5 % (design iii)
Water Scrubber	Electricity consumption	Compression 0.1-0.15 kWh/Nm^3 CH_4
		0.05-0.1 kWh/Nm^3 CH_4 (water pump)
		0.01-0.05 kWh/Nm^3 CH_4 (water cooling system)
	Availability	95-96%
	O&M (Annually Relative to Investment Cost)	2-3 %
	Recovery	99%
	Methane concentration	98 %
Amine scrubber	Electricity consumption	0.14 kWh/Nm^3 CH_4
	Heat consumption	0.55 kWh/Nm^3 CH_4
	Availability	96%
	Recovery	>99.9 %
	O&M (Annually Relative to Investment Cost)	3-4%
	Water usage	0.00003 m3/Nm^3 CH_4
	Chemicals	0.00003 kg/Nm^3 CH_4
	Investment Cost	Included: Transport,commissioning,
		heat recovery, analysis equipment

Table A.13: Economic and technical Characteristics for Amine Scrubber facility, from SGC [43]

Amine scrubber	Characteristic	Value
	Electricity consumption	0.14 kWh/Nm^3 CH_4 (upgrading process)
		0.12 kWh/Nm^3 CH_4 (compression for injection)
	Heat consumption	0.55 kWh/Nm^3 CH_4 (stripper process)
	If DH heat supply	+ 0.05 kWh$_{el}$/Nm^3 CH_4
	Availability	96%
	Recovery	>99.9 %
	O&M	3%
	Water usage	0.00003 m3/Nm^3 CH_4
	Chemicals	0.00003 kg/Nm^3 CH_4
	Capacity	1100 Nm^3 CH_4/h
Investment	Upgrade facility	1600 Euro/Nm^3 input CH_4/h
	Injection cost	1350 Euro/Nm^3 CH_4/h

Table A.14: Input/Output characteristics of an amine scrubber with heat provided by a biogas boiler, from [43]

Input	Value per Nm^3 CH_4 input
Biogas	9,97 kWh
Power	0.14 kWh
Heat	0.55 kWh
Output	**Value per Nm^3 CH_4 input**
Upgraded biogas	9.27 kWh

The specific investment of cost for amine scrubbers varying for raw biogas input can be observed in figure A.3. Not included is extra compression and RTO for H_2S removal.
The specific investment of cost for upgrade units by removal of CO_2 varying for raw biogas input can be observed in figure A.3.

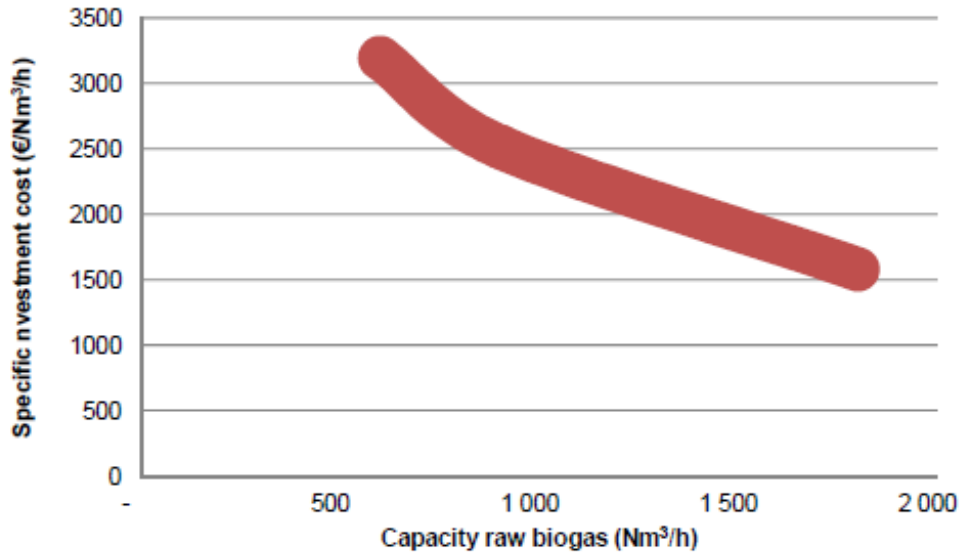

Figure A.2: Specific investment of amine scrubbers cost for raw biogas input, from [43]

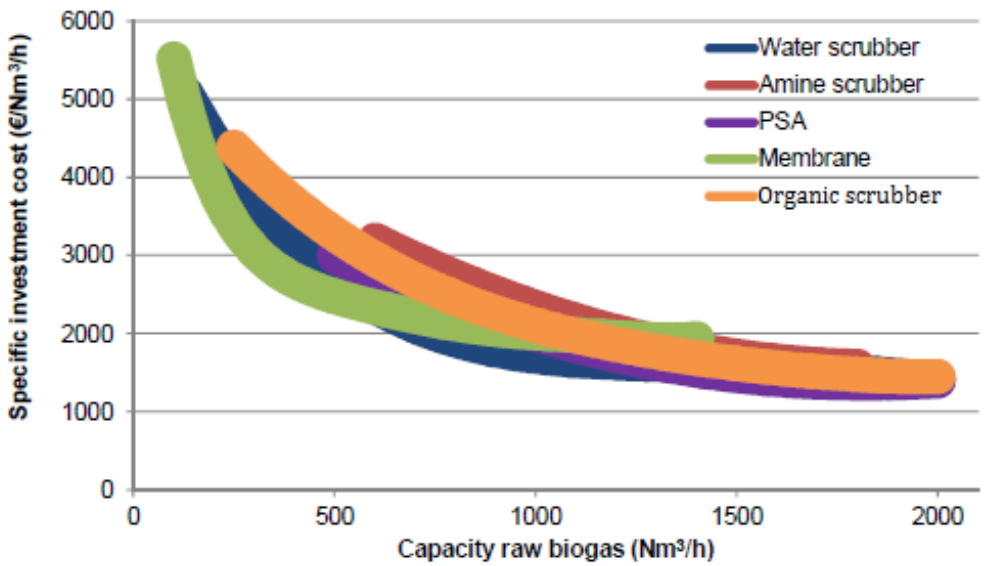

Figure A.3: Specific investment of cost for raw biogas input, from [43]

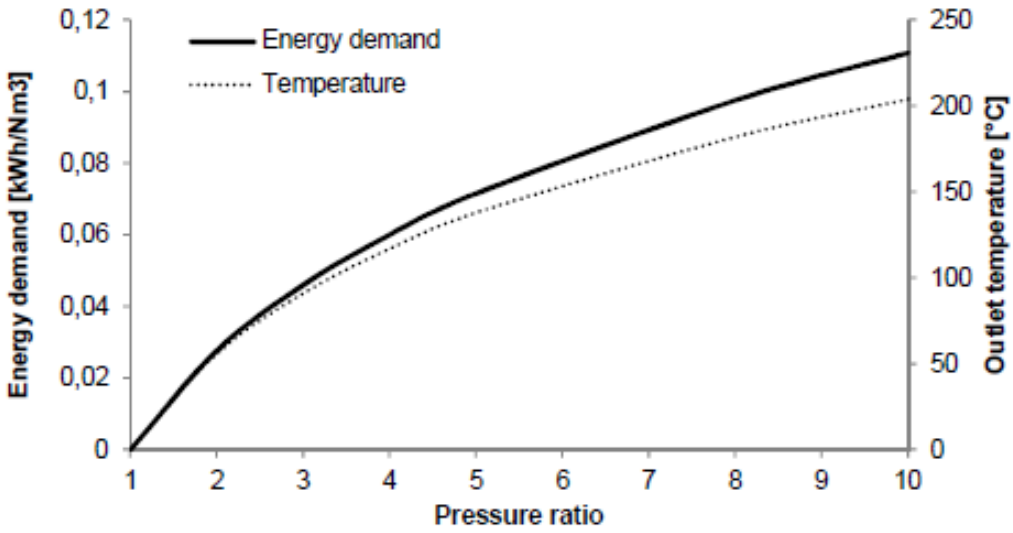

Figure A.4: Energy demand for compression of biogas by a specific pressure ration and the outlet temperature, from [43]

The energy demand for compressing of biogas can be seen in figure A.4. The gas is considered to be cool before compression, and thus compressing may need to to through more stages to control temperature.

Upgrading by SOEC and methanation of CO_2

Table A.15: Economical characteristics of components used for upgrading with SOEC and a methanator

Component	Investment cost	Lifetime
SOEC	1000 (EURO14/Nm^3 H_2)	5 (years)
Methanator	3090 (EURO14/Nm^3 upgraded biogas)	20 (years)
H2 Storage	14(EURO14/kWh)	20 (years)

The investment costs for the SOEC and the methanator are estimated by Topsøe in cite [51]. The components are scaled to match a 7500000 (Nm^3 biogas/year) biogas production facility. The hydrogen storage costs are estimated in [52]. The fixed O&M costs is assumed to be 5 % as in [52]. The investment costs include auxiliary costs such as cleaning biogas for sulphuric components and upgrading equipment.
Electricity for preheating and compression of SNG to 40 bar is included in the SOEC component
99 % of the energy of the upgraded biogas is from CH4, 1 % from Hydrogen gas. The minimum load of the methanator is 20 %, and is included in the model as described in section 5.1.

Table A.16: Flow Characteristic of an SOEC unit

Input	Value per Nm^3 Steam input
Steam	0.52
Power	3.25 kWh
Output	**Value per Nm^3 Steam input**
H2	3.0 kWh
Heat (DH)	0.5 kWh
Heat (Loss)	0.27 kWh

Table A.17: Flow characteristic of a methanator, from Ea in [52]

Input	Value per kWh biogas input	
	Input	
	Biogas	1 kWh
	H2	0.65 kWh
Output	**Value per kWh biogas input**	
	Ugraded biogas	1.54 kWh
	Heat (Steam)	0.11 kWh

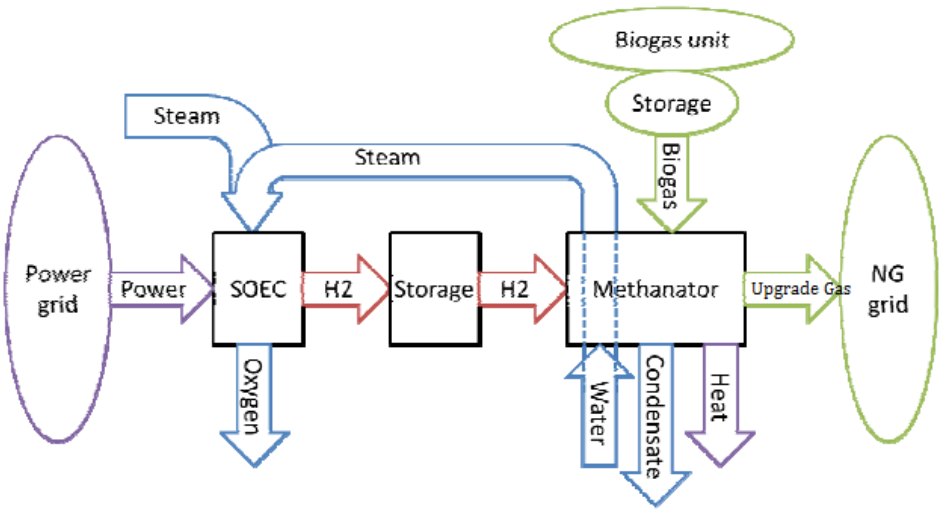

Figure A.5: Flow diagram, SOEC plant where biogas is mixed with hydrogen in a methanator, from [52]

A.3 CO_2 Quota Price Projection

The CO_2 price projection used in the analysis can be seen in figure A.6

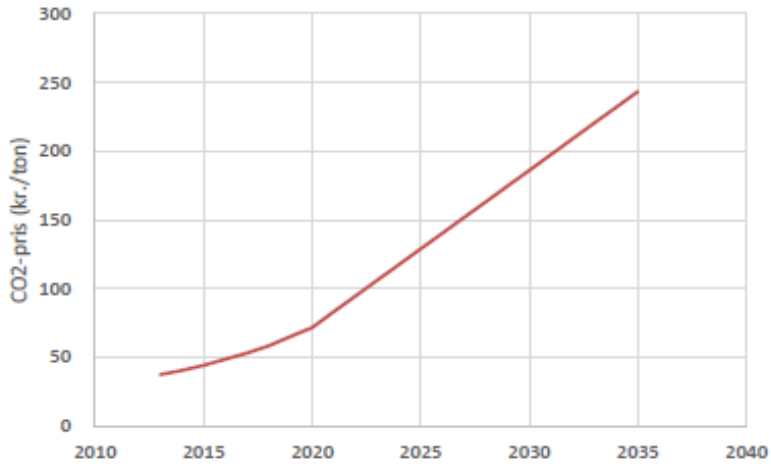

Figure A.6: CO_2 price projection

The Biogas requirements for biogas and upgraded biogas for year 2014 to 2050.

A.4 DH Areas in Balmorel

In Denmark 420 different DH networks presently exists. Around 3% of the DH networks covers 70 % of the heat demand delivered to the grid. To represent all DH networks is time consuming both for data collection and import to the model, but most important of all increasing the computational time of solving the model. Therefore the smallest networks have been aggregated in larger networks.

The procedure for aggregation of the small DH networks , was devised and carried out by EA Energy Analysis in [17]. The large DH areas are DH areas which have a central power plant connected along with DH areas which have a heating demand above 1000 TJ and DH areas which are under 1000 TJ but have a municipal waste plant connected. For DH areas below 1000 TJ an aggregation of capacity is done into 6 areas in regions DK West and 5 in DK East. The Aggregated areas are defined by a dominating fuel and a dominating technology as seen in table A.18. For each real DH area which is under 1000 TJ the dominating fuel and technology is calculated by the data sheet from the "Energiproducenttælling" and the capacity is added to a Balmorel DH area.

Furthermore 2 industrial DH areas is defined, 1 in DK West and DK East. The DH industry areas covers the producers for whom the heat production only covers their own process heat i.e they are not connected to a DH grid the industry producers of heat which are connected to a DH grid, for which the share of process heat production is assigned to the industry area.
In figure A.7 the heat producing units aggregated into small areas with NG units is shown for western and eastern Denmark. The heat producing units are geographically far apart.

Table A.18: Aggregation of Small DH areas in Balmorel

Area name	Main fuel	Main technology
DK_SA_E_BG	Biogas	None
DK_SA_E_NG_CHP	Natural gas	CHP
DK_SA_E_NG_HO	Natural gas	HO
DK_SA_E_ST_CHP	Straw	CHP
DK_SA_E_ST_HO	Straw	HO
DK_SA_E_WO_HO	Wood chips	HO
DK_SA_W_BG	Biogas	None
DK_SA_W_NG_CHP	Natural gas	CHP
DK_SA_W_NG_HO	Natural gas	HO
DK_SA_W_ST_HO	Straw	HO
DK_SA_W_WO_CHP	Wood chips	CHP
DK_SA_W_WO_HO	Wood chips	HO

A.5 Biogas potentials assigned to DH Areas in Balmorel

Table A.19: Biomass potentials assigned to model DH areas

Model DH Name	Biomass MAN potential (TJ)
DK_E_Industry_A	99,9
DK_W_Industry_A	1824,4
DK_CA_Esb	149,7
DK_CA_Hern	90,3
DK_CA_Kal	42,7
DK_CA_KBH	15
DK_CA_Odense	50,9
DK_CA_Randers	30,9
DK_CA_Roenne	38,4
DK_CA_TVIS	129
DK_CA_Aab	76,2
DK_CA_Aal	35,7
DK_CA_Aarhus	59,2
DK_E_DTU	0,3
DK_MA_Grenaa	57,3
DK_MA_Hil	4,6
DK_MA_Hjoerring	91,4
DK_MA_Holst	73,3
DK_MA_Horsens	34,7
DK_MA_NrdOstSj	6,2
DK_MA_Silk	38,9
DK_MA_Sndborg	49,3
DK_MA_Viborg	96,7
DK_MAM_Frdhavn	20,6
DK_MAM_Had	70,9
DK_MAM_Hammel	27,5
DK_MAM_Hobro	40,3
DK_MAM_Naestved	27,8
DK_MAM_NrAlslev	17,6
DK_MAM_Nyborg	38,9
DK_MAM_Nyk	17,6
DK_MAM_Skagen	20,6
DK_MAM_Slagelse	10,4
DK_MAM_Svend	20,6
DK_MAM_Thisted	57,6
DK_MAM_Aars	49,1
DK_SA_E_BG	85,8
DK_SA_E_NG_CHP	431,8
DK_SA_E_NG_HO	196,9
DK_SA_E_ST_CHP	46,1
DK_SA_E_ST_HO	166,3
DK_SA_E_WO_HO	143,4
DK_SA_W_BG	504,8
DK_SA_W_EB	564,2
DK_SA_W_NG_CHP	2190,4
DK_SA_W_NG_HO	1824,4
DK_SA_W_ST_HO	560,5
DK_SA_W_WO_CHP	315,7
DK_SA_W_WO_HO	1217,6

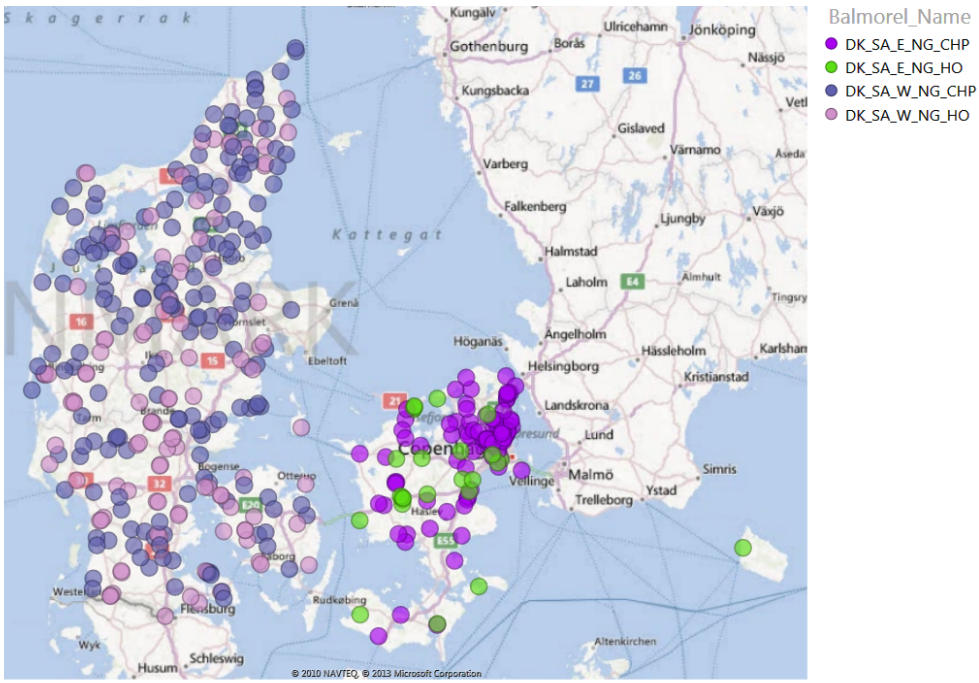

Figure A.7: Geographical distribution of heat producing units in small DH Areas with NG production, from [67]

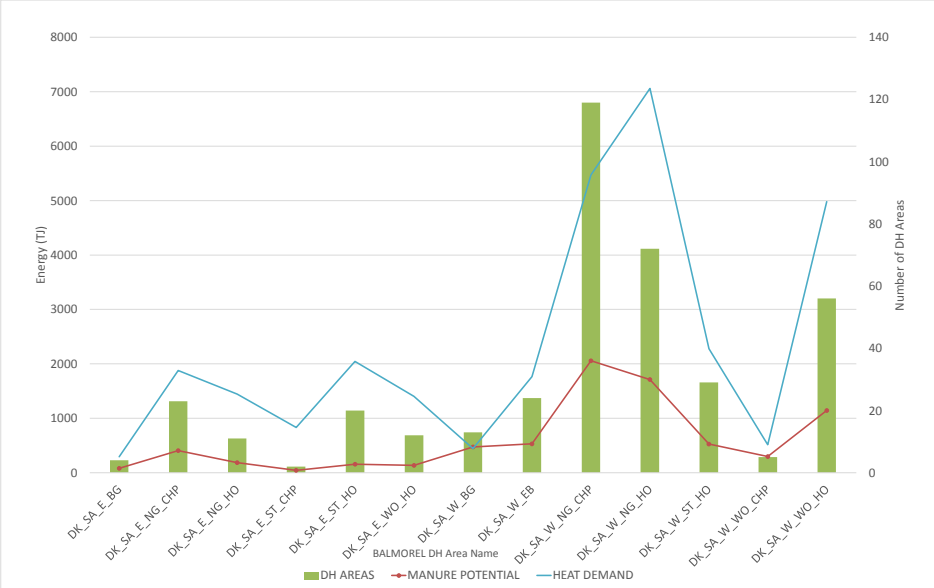

Figure A.8: BG distribution

B

Verification

B.1 Comparison with Ea case scenarios

In figure B.1 the biogas production and heat demand for the validation case can be observed. In figure B.2 the biogas production and the electricity production for the biogas engine is displayed.

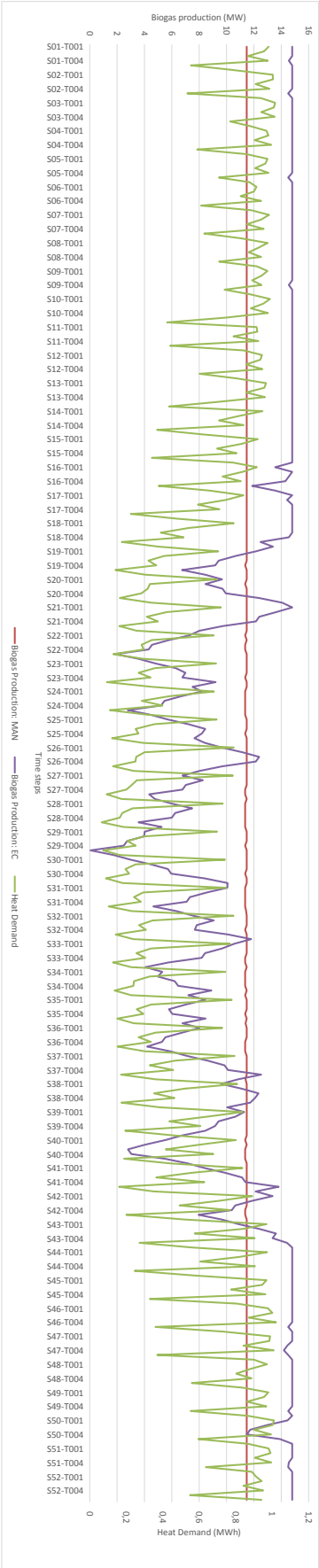

Figure B.1: Biogas Production and heat demand for validation cases

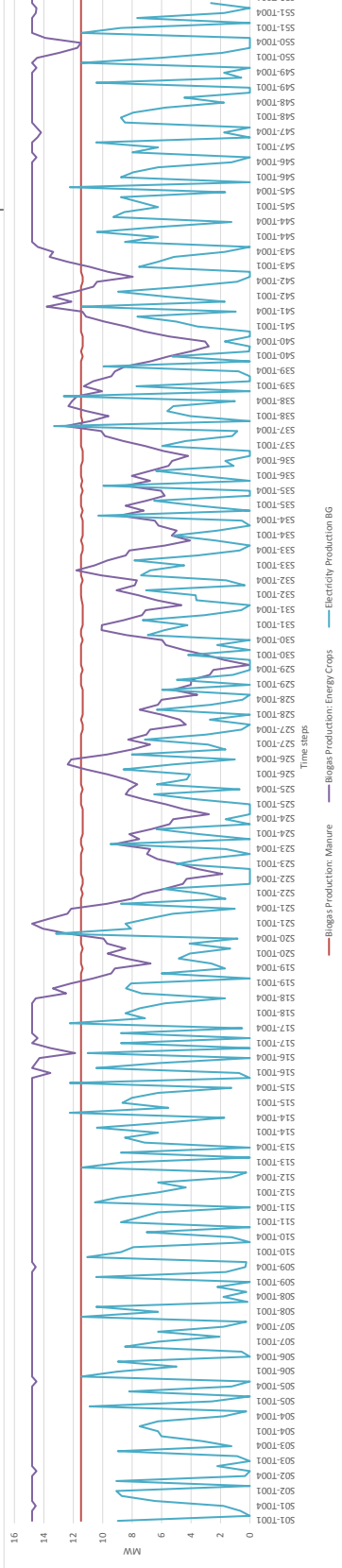

Figure B.2: Biogas Production and heat demand for validation cases

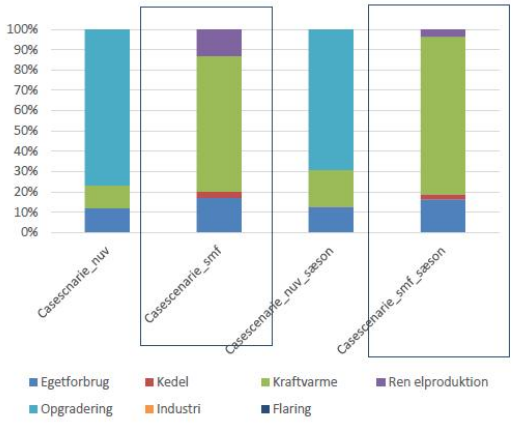

Figure B.3: Annual Biogas use for Ea case scenarios [22]

B.2 Time Step (t)aggregation in Balmorel

To reduce computation time when solving large problems, an aggregation of the time periods t is performed such that timesteps in each season is represented by 6 time steps. When the simulated number of seasons is set to 52, each season can be thought of as representing weeks. Each season can be represented with maximum 168 time periods, such when S=52, 168 time steps can be thought of as representing hours in a week. The algorithm for choosing the aggregation has been developed by Ea energi analyse. The aggregation aims to maintain as much variability between time steps as possible. From table B.1 the time aggregation for all time steps can be observed. Time step t001 is e.g hours H09-H13 in Weekdays Monday-Friday and time step t004 is H18 in week days Monday-Friday. In the table the week days have the abbreviation WD (week day), e.g WD1 is Monday. The other time step aggregations are self explanatory from B.1.

Table B.1: Time aggregation in Balmorel

	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
t001									X	X	X	X	X											
t002														X	X	X	X		X	X				
t003						X	X	X													X	X		
t004																		X						
t005	X	X	X	X	X																		X	X
t006							X	X	X	X	X	X	X	X	X	X	X	X	X	X	X			
	WD1	WD2	WD3	WD4	WD5	WD6	WD7																	
t001	X	X	X	X	X																			
t002	X	X	X	X	X																			
t003	X	X	X	X	X																			
t004	X	X	X	X	X																			
t005	X	X	X	X	X	X	X																	
t006						X	X																	

C

Energy System Tools

C.1 Mathematical syntax to GAMS syntax

In this section the mathematical syntax used to describe the model application and the main functionalities of Balmorel is listed as it's proper GAMS syntax in the table below. To the right is the GAMS syntax, to the left is the Mathematical syntax used in the report.

MATH	**GAMS**
Sets and indices	
$a, \mathbb{A}$	AAA
e	e
f	FFF
$g, ig, \mathbb{G}$	G,IGALIAS
$t, tf, tl, \mathbb{T}$	TTT
$s, sf, sl, \mathbb{S}$	IS3
$r, \mathbb{R}$	IR
in	in
out	out
Parameters	
C^{inv}	GINVCOST
C^{fix}	GOMFCOST
C^{var}	GOMVCOST
C^{ext}	ITAX_X_Y, where X could be e.g "CO2"
DE	IDE_SUMST
DH	IDH_SUMST
R	GKDERATE
K	GKFX
W	IM_X, where X could be e.g CO2
η	GDATA(G,'GDFE')
η^{loss}	XLOSS
$KX^{\max}$	XMAXINVC
A_f	POLREQ(YYY,POLAREA,'MAXX'),Where X could be "Straw"
FB	FB

FLW	FLW
BGQ	BIOGASREG
CAP^{min}	MINCAP
$WHOUR$	IHOURSINST
Variables	
VG	VGH_T,VGE_T
VX	VX_T
VK	VGKN
VS	VHSTOVOLT (for heat storage)
VF	VGF_T
Z	VOBJ
VL	VHSTOLOADT (for heat storage)
VU	VGH_T,VGHN_T (generation on storage units)
VW	VNBGFLOW_T

D

Additional Charts for Results Section

D.1 Heat generation Denmark

The annual heat generation for the medium waste areas (MA) and the small waste areas (MAM) can be observed in figures D.1 and D.2, respectively.

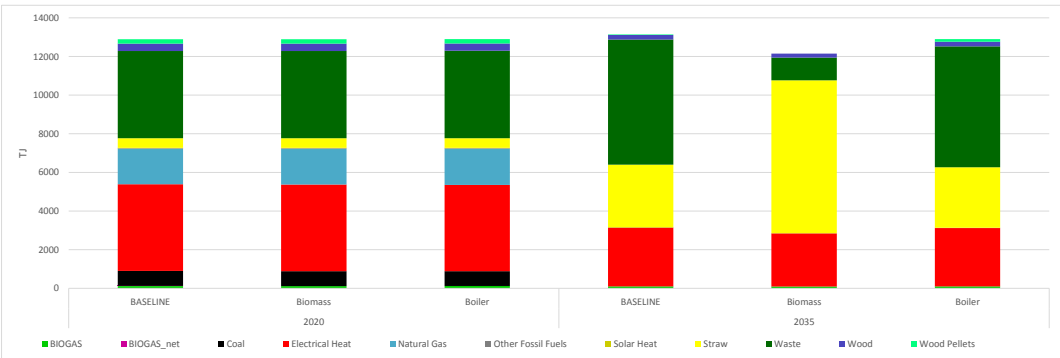

Figure D.1: Heat generation, Medium Waste Areas

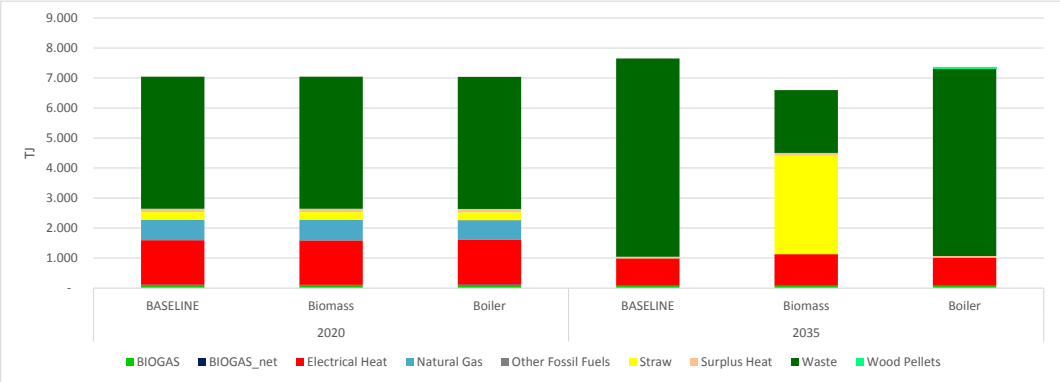

Figure D.2: Heat generation, Small Waste Areas

E

GAMS CODE

E.1 New Equations

Here GAMS code of the new equations in the add-on.

```
EQUATIONS
* BALANCE EQUATIONS FOR FLOW AND STORAGE


QNBGIOBALANCE(AAA,S,T,G,e)      'Balance of in and out flows for existing and new technologies,Handles technologies which
QNBGFLOWRATIO_IN(AAA,S,T,G,e)     'Flowratio between energy types on intput, existing and new generation'
QNBGFLOWRATIO_OUT(AAA,S,T,G,e)    'Flowratio between energy types on output, existing and new generation'

QNBGSTOBALANCE(AAA,S,T,G,e)     'Balance of storage between timesteps'

* STORAGE CAPACITY EQUATIONS
QNBGSTORAGEMAX(AAA,S,T,G,e)     'Storage limit cannot exceed the installed capacity '

* FLOW CAPACITY EQUATIONS
QNBGLOADMAX(AAA,S,T,io,G,e)  'Limit outgoing maxflow on existing and new capacities that is NOT INBGSTO (INBGNOTSTO in
ligningerne i BAL, dog uden decompff og refurb'
QNBGLOADMIN(AAA,S,T,io,G,e)  'Limit outgoing minflow on existing and new capacities — relevant for methanator and bioga

* BIOGAS REQUIREMENT for EACH AREA . 1 and 3 or 0 should be set.
QEQNBGAREA1(AAA)                  'A certain amount of MANURE biogas should be produced'
QEQNBGAREA2(AAA)                  ' The crop biogas cannot exceed 3 x the maure biogas potential'
QEQNBGAREA3                       'A certain amount of CROPS biogas should be produced'
QEQNBGAREA(AAA)                 'A certain amount of upgraded biogas should be utilized'
QEQNBGAREAsoec(AAA)             'a certain amunt is upgraded'
*Flow demand for biogas

QNBGFLOWDEMAND(AAA,S,T)    'The amount of biogas used (VGF_T and VGFN) at each timestep for biogas technologies in an a


QFLOWGRADDW(AAA,S,T,G,IGALIAS,e)  'Gradient flow downwards for technologies'
QFLOWGRADDWTC1(AAA,S,T,G,IGALIAS,e)  'gradient flow upwards for technologies'
QFLOWGRADDWTC2(AAA,S,T,G,IGALIAS,e)  'gradient flow upwards for technologies'

QFLOWGRADUP(AAA,S,T,G,IGALIAS,e)  'gradient flow upwards for technologies'
QFLOWGRADUPTC1(AAA,S,T,G,IGALIAS,e)  'gradient flow upwards for technologies'
QFLOWGRADUPTC2(AAA,S,T,G,IGALIAS,e)  'gradient flow upwards for technologies'


;
```

```
*-----------------------------------------------------------------------------
* BALANCE EQ
*-----------------------------------------------------------------------------

* $(sum(io,FB(IA,G,io,e)) for alle IA,G,e der har input og output
* flowknudepunktsligning: Styrer at summen af det de flows der kommer ind i et knudepunkt
*skal være
*det samme som summen af de flows der kommer ud af knudepunktet, styret af et ind og ud flow
* forhold sum(e,FB(e))

QNBGIOBALANCE(IA,IS3,T,G,e)$(sum(io,FB(IA,G,io,e)))..

* SUM(e,VF(g,e,in))/SUM(e,FB(g,e,in)) = SUM(e,VF(g,e,out))/SUM(e,FB(g,e,out))
* of a given technology [g]

            sum(e1$FB(IA,G,'out',e1),FB(IA,G,'out',e1))*

            sum((IGALIAS,e1)$FLW(IA,IGALIAS,G,e1),VNBGFLOW_T(IA,IS3,T,IGALIAS,G,e1))

            =E=

            sum(e1$FB(IA,G,'in',e1),FB(IA,G,'in',e1))*

            sum((IGALIAS,e1)$FLW(IA,G,IGALIAS,e1),VNBGFLOW_T(IA,IS3,T,G,IGALIAS,e1))
           ;

*This equation ensures that the right compositiuon of energy flows e enters a vertice.
* For all areas that has g,e that has a

QNBGFLOWRATIO_IN(IA,IS3,T,G,e)$(FB(IA,G,'in',e))..
*15-04 try to change 'inøø' to io

* FB(e)/SUM(e,FB(e)) = VFLOW(e)/SUM(e,VFLOW(e))

            SUM(e1$FB(IA,G,'in',e1),FB(IA,G,'in',e1))*SUM(IGALIAS$FLW(IA,IGALIAS,g,e),  VNBGFLOW_T(IA,IS3,T,IGALIAS,G,
            =E=
            FB(IA,G,'in',e)*SUM((IGALIAS,e1)$FLW(IA,IGALIAS,g,e1),VNBGFLOW_T(IA,IS3,T,IGALIAS,G,e1))
            ;


QNBGFLOWRATIO_OUT(IA,IS3,T,G,e)$(FB(IA,G,'out',e))..
* FB(e)/SUM(e,FB(e)) = VFLOW(e)/SUM(e,VFLOW(e))

            SUM(e1$FB(IA,G,'out',e1),FB(IA,G,'out',e1))*SUM(IGALIAS$FLW(IA,G,IGALIAS,e),VNBGFLOW_T(IA,IS3,T,G,IGALIAS,
            =E=
            FB(IA,G,'out',e)*SUM((IGALIAS,e1)$FLW(IA,G,IGALIAS,e1),VNBGFLOW_T(IA,IS3,T,G,IGALIAS,e1))
             ;



QNBGSTOBALANCE(IA,IS3,T,G,E)$(sum(IGALIAS,FLW(IA,IGALIAS,G,e)) and IGNBGSTO(G))..
* Current storage balance plus flow in
            VNBGSTOVOLT(IA,IS3,T,G,e)
 /*Load storage*/
            +IHOURSINST(IS3,T)*sum(IGALIAS$FLW(IA,IGALIAS,G,e),VNBGFLOW_T(IA,IS3,T,IGALIAS,G,e))
 /*Unload storage*/
            -IHOURSINST(IS3,T)*sum(IGALIAS$FLW(IA,G,IGALIAS,e),VNBGFLOW_T(IA,IS3,T,G,IGALIAS,e))
            =E=
* Equals storage balance at next time point plus flow out
            VNBGSTOVOLT(IA,IS3,T++1,G,e)

            ;

*TODO:
*EFF(G)bruges om heatstorages og ikke biogas/ H2 storage. Derfvor er den slettet
*fra den adaptede ligning.
*Her er der ikke beregnet noget energitab i storage, men kun driftsomkostinger.

*Two new domains has been added to the storage variable VNBGSTOVOLT to handle different
* storages technologies (g)
```

```
*with different flow types (e)
* IHOURSINST has been set such that VNBGFLOW_T is assumed to be in MW and
* VNBGSTOVOLT in MWh



*-----------------------------------------------------------------------------
* STORAGE CAPACITIES
*-----------------------------------------------------------------------------

*SUM(IGNBGSTO, IAGK_Y(IA,IGNBGSTO)+IAGKN(IA,INBGSTO)) -> limits areas
*SUM(IGALIAS,FLW(IA,IGALIAS,G,e) -> limits areas and G
*IGNBGSTO only storage g's, therefore limiting e when working with the above condition

QNBGSTORAGEMAX(IA,IS3,T,G,e)$(SUM(IGALIAS,FLW(IA,IGALIAS,G,e)) and IGNBGSTO(G) )..

                 SUM(IGNBGSTO$IAGK_Y(IA,IGNBGSTO),IGKFX_Y(IA,IGNBGSTO)+
                                                 IGKVACCTOY(IA,IGNBGSTO)
                                                                       )

                 +SUM(IGNBGSTO$IAGKN(IA,IGNBGSTO),VGKN(IA,IGNBGSTO)
                 )
                 =G=

               VNBGSTOVOLT(IA,IS3,T,G,e)
                  ;

*-----------------------------------------------------------------------------
* FLOW CAPACITIES
*-----------------------------------------------------------------------------


QNBGLOADMAX(IA,IS3,T,io,G,e)$(sameas(io,'out') and (FB(IA,g,io,e) and IGNBGNOSTO(G)))..
* Outgoing flow of a given fuel is upwards limited by...

                 sum(IGALIAS$FLW(IA,G,IGALIAS,e),VNBGFLOW_T(IA,IS3,T,G,IGALIAS,e))

                  =L=
*GKDERATE(IA,G,IS3,T)*
                 IOF0P089*FB(IA,G,io,e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)
                                                                +IGKFX_Y(IA,G))
                  ;

QNBGLOADMIN(IA,IS3,T,io,G,e)$(sameas(io,'out') and (FB(IA,g,io,e) and IGNBGNOSTO(G)) and CAP(g,'min'))..
* Outgoing flow of a given fuel is upwards limited by...

                 sum(IGALIAS$FLW(IA,G,IGALIAS,e),VNBGFLOW_T(IA,IS3,T,G,IGALIAS,e))

                  =G=
**GKDERATE(IA,G,IS3,T)
                 IOF0P089*CAP(g,'min')*FB(IA,G,io,e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)
                                                                +IGKFX_Y(IA,G))
                  ;

*-----------------------------------------------------------------------------
*BIOGAS REQUIREMENTS
*-----------------------------------------------------------------------------

* Exact required fuel use for biogas areas and technology group

$ifi %test%==no QEQNBGAREA1(IA)$NBG_DK(IA)..
$ifi %test%==yes QEQNBGAREA1(IA)$NBG_DK1(IA)..

      SUM((IS3,T)$FLW(IA,'BiogasPlant-MAN-10-30','BIOGASPLANT','biogas'), IOF3P6*IHOURSINST(IS3,T)*VNBGFLOW_T(IA,IS3,T,

$ifi %VNOBGFORCE%==no        =e=
$ifi %VNOBGFORCE%==yes       =l=

     IBIOGASREQMAN_Y(IA)*IOF1000


        ;

```

```
$ifi %test%==no QEQNBGAREA2(IA)$NBG_DK(IA)..
$ifi %test%==yes QEQNBGAREA2(IA)$NBG_DK1(IA)..

        SUM((IS3,T)$FLW(IA,'BiogasPlant-CROPS-10-30','BIOGASPLANT','biogas'), IOF3P6*IHOURSINST(IS3,T)*VNBGFLOW_T(IA,I


       =l=

     IBIOGASREQMAN_Y(IA)*IOF1000*IOF3

*TO GET


        ;

QEQNBGAREA3..

      SUM((IA,IS3,T)$FLW(IA,'BiogasPlant-CROPS-10-30','BIOGASPLANT','biogas'), IOF3P6*IHOURSINST(IS3,T)*VNBGFLOW_T(IA,

$ifi %VNOBGFORCE%==no        =e=
$ifi %VNOBGFORCE%==yes       =l=

     IBIOGASREQCROPS_Y*IOF1000
*TO GET ibiogascrops to GJ


        ;


QEQNBGAREA(IA)$NBG_DK2(IA)..

    IBIOGASREQ_Y(IA)

        =e=
*MAKE SURE YOU HAVE THE RIGHT VALUES TJ,MWH OR GJ!
$ifi %gkfxSR%==yes SUM((IS3,T)$FLW(IA,'BiogasPlant-CROPS-10-30','BIOGASPLANT','biogas'), IHOURSINST(IS3,T)*VNBGFLOW_T(

$ifi %gkfxSR%==no SUM((IS3,T)$FLW(IA,'BiogasPlant-MAN-10-30','BIOGASPLANT','biogas'), IHOURSINST(IS3,T)*VNBGFLOW_T(IA,
;

QEQNBGAREAsoec(IA)$NBG_DK2(IA)..

    IBIOGASREQ_Y(IA)/4

        =e=
*test upgrade

SUM((IS3,T)$FLW(IA,'methanator','BiogasUpg','Biogas_net'), IHOURSINST(IS3,T)*VNBGFLOW_T(IA,IS3,T,'methanator','BiogasU
;

/*
    SUM((G,IS3,T)$( IGNBGUPG2(G)and (IAGK_Y(IA,G) or IAGKN(IA,G))),
         IHOURSINST(IS3,T)*IOF3P6*VNBGFLOW_T(IA,IS3,T,G,'Biogasupg','BIOGAS') )
+
SUM((G,IS3,T)$(INBGF(G) and (IAGK_Y(IA,G) or IAGKN(IA,G))),
    IHOURSINST(IS3,T)*IOF3P6*( VGF_T(IA,G,IS3,T)$IAGK_Y(IA,G)
                                    + VGFN_T(IA,G,IS3,T)$IAGKN(IA,G)) )
*/



*-----------------------------------------------------------------------------
*Flow Demand
*The biogas used on each production facility at each time step should equal the flow
*from biogasproduction or biogas storage
* Furthermore, the fuel used should not be included in the QOBJ i BAL, as the cost is
* assigned to the production and storage.
*-----------------------------------------------------------------------------

$ifi %test%==no QNBGFLOWDEMAND(IA,IS3,T)$( nbg_dk(IA))..
$ifi %test%==yes QNBGFLOWDEMAND(IA,IS3,T)$( nbg_dk2(IA))..
```

```
                                    SUM((IGALIAS)$FLW(IA,IGALIAS,'net','biogas'), VNBGFLOW_T(IA,IS3,T,IGALIAS,'net','biog
                                     =e=
                                    SUM(G$(INBGF(G)and IAGK_Y(IA,G)),VGF_T(IA,G,IS3,T))+SUM(G$(INBGF(G) and IAGKN(IA,G)),
          ;



*-----------------------------------------------------------------------------
* OLD COMPONENT GRADIENTS (Working on biogas ec crops plant)
*-----------------------------------------------------------------------------

*IKKE UDKOMMENTERET

QFLOWGRADUP(IA,S,T+1,G,IGALIAS,e)$(GRAD(G) and FLW(IA,G,IGALIAS,e))..
* Increase in flows between t and t+1 are constrained by the gradient and the length of the period in the next timestep

VNBGFLOW_T(IA,S,T+1,G,IGALIAS,e)-VNBGFLOW_T(IA,S,T,G,IGALIAS,e)-VQUP1(IA,S,T,G,IGALIAS,e,'IMINUS')+VQUP1(IA,S,T,G,IGALI
                 =L=
IHOURSINST(S,T+1)*GRAD(G)*FB(IA,G,'out',e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)+IGKFX_Y(IA,G))

;
/*
QFLOWGRADUPTC1(IA,SFIRST,TFIRST,G,IGALIAS,e)$(GRAD(G) and FLW(IA,G,IGALIAS,e))..
* Initialise for first timestep and first season: Flow needs to be lower than capacity

VNBGFLOW_T(IA,SFIRST,TFIRST,G,IGALIAS,e)
                 =L=
FB(IA,G,'out',e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)+IGKFX_Y(IA,G))
;
*/


QFLOWGRADUPTC2(IA,S+1,TFIRST,G,IGALIAS,e)$(GRAD(G) and FLW(IA,G,IGALIAS,e))..
* Increase in flows between tlast and tfirst in between seasons is contrained by:



$ifi %hedetime%==yes VNBGFLOW_T(IA,S+1,TFIRST,G,IGALIAS,e)-VNBGFLOW_T(IA,S,'t168',G,IGALIAS,e)-VQUP2(IA,S+1,TFIRST,G,IGA
$ifi %hedetime%==no VNBGFLOW_T(IA,S+1,TFIRST,G,IGALIAS,e)-VNBGFLOW_T(IA,S,'t006',G,IGALIAS,e)-VQUP2(IA,S+1,TFIRST,G,IGAL

                 =L=
IHOURSINST(S+1,TFIRST)*GRAD(G)*FB(IA,G,'out',e)*FB(IA,G,'out',e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)+IGKFX_Y(IA,G)
;



QFLOWGRADDW(IA,S,T+1,G,IGALIAS,e)$(GRAD(G) and FLW(IA,G,IGALIAS,e))..
* Decrease in flows between t and t+1 are contrained by:

VNBGFLOW_T(IA,S,T,G,IGALIAS,e)-VNBGFLOW_T(IA,S,T+1,G,IGALIAS,e)-VQDOWN1(IA,S,T,G,IGALIAS,e,'IMINUS')+VQDOWN1(IA,S,T,G,IG
                 =L=
IHOURSINST(S,T+1)*GRAD(G)*FB(IA,G,'out',e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)+IGKFX_Y(IA,G))
;



QFLOWGRADDWTC2(IA,S+1,TFIRST,G,IGALIAS,e)$(GRAD(G) and FLW(IA,G,IGALIAS,e))..
* Increase in flows between t and t+1 are contrained by:

$ifi %hedetime%==yes VNBGFLOW_T(IA,S,'t168',G,IGALIAS,e) -VNBGFLOW_T(IA,S+1,TFIRST,G,IGALIAS,e)-VQDOWN2(IA,S+1,TFIRST,G,
$ifi %hedetime%==no VNBGFLOW_T(IA,S,'t006',G,IGALIAS,e) -VNBGFLOW_T(IA,S+1,TFIRST,G,IGALIAS,e)-VQDOWN2(IA,S+1,TFIRST,G,

                 =L=
IHOURSINST(S+1,TFIRST)*GRAD(G)*FB(IA,G,'out',e)*(VGKN(IA,G)$IAGKN(IA,G)+IGKVACCTOY(IA,G)+IGKFX_Y(IA,G))
;
```

E.2 Additions to and editing of existing equations.inc

GAMS code showing additions and editing of original E&F model equations that has been necessary to implement to incorporate the add-in functionalities.

QOBJ

Objective function addition and editing.

```
* Operation and maintainance cost: ADDED


      +  SUM((IA,G,IGALIAS,e)$(NBGOMVAR(G,e)and FLW(IA,G,IGALIAS,e)),NBGOMVAR(G,e)*SUM((IS3,T), IHOURSINST(IS3,T) * VN

* Cost of fuel flow consumption during the year: ADDED

  + SUM((IA,G,IGALIAS,e)$(FLW(IA,G,IGALIAS,e)) ,
                 IFLOWP_Y(IA,G,IGALIAS,e) * SUM((IS3,T), IHOURSINST(IS3,T) * VNBGFLOW_T(IA,IS3,T,G,IGALIAS,e)))

*Biogas use is not accruing any costs: EDIT

$ifi not %NEWBIOGAS%==yes SUM((IAGK_Y(IA,G),FFF)$IGF(G,FFF),
$ifi %NEWBIOGAS%==yes     SUM( (IA,G,FFF)$( IGF(G,FFF) and ((IAGK_Y(IA,G)-INBGGAREA(IA,G)) and IAGK_Y(IA,G))),
                                IFUELP_Y(IA,FFF) * IOF3P6 * SUM((IS3,T), IHOURSINST(IS3,T) * VGF_T(IA,G,IS3,T))
                            )

$ifi not %NEWBIOGAS%==yes +SUM((IAGKN(IA,G),FFF)$IGF(G,FFF),
$ifi %NEWBIOGAS%==yes     +SUM((IA,G,FFF)$(IGF(G,FFF) and ((IAGKN(IA,G)-INBGGAREA(IA,G)) and IAGKN(IA,G))),
                                IFUELP_Y(IA,FFF) * IOF3P6 * SUM((IS3,T), IHOURSINST(IS3,T) * VGFN_T(IA,G,IS3,T))
                            )
```

QEEQ

Electricity balance equation

```
*Production of Power from the network NET to the NBG techs; ADDED

-SUM((IA,G)$( (RRRAAA(IR,IA)) AND FLW(IA,'net',G,'power') ) ,VNBGFLOW_T(IA,IS3,T,'net',G,'power'))-SUM((IA,G)$( (RRRAA

*Production of power from NBG techs IGALIAS to the network NET

*+SUM((IA,IGALIAS)$( ((RRRAAA(IR,IA)) AND FLW(IA,IGALIAS,'net','power')),VNBGFLOW_T(IA,IS3,T,IGALIAS,'net','power'))
```

QHEQ

Heat balance equation

```
*Production of heat from the DH network NET to the NBG techs: ADDED

-SUM((G)$FLW(IA,'net',G,'heat') ,VNBGFLOW_T(IA,IS3,T,'net',G,'heat'))

*Production of heat from NBG techs IGALIAS to the DH network NET

+SUM((G)$FLW(IA,G,'net','heat') ,VNBGFLOW_T(IA,IS3,T,G,'net','heat'))
```

QPOLEQFUEL

Biogas policy equation from "policies" add-on.

```
* Exact required fuel use for policy ares and tecnology group
QPOLEQFUEL(POLAREA,POLICY)$(IPOLREQ_Y(POLAREA,POLICY) and POLTYP(POLICY,'EQFUELUSE')) ..


$ifi %VALIDATE%==no SUM((IA,IS3,T,IGALIAS)$FLW(IA,IGALIAS,'Biogasupg','biogas_net'), IHOURSINST(IS3,T)*VNBGFLOW_T(IA,IS

$ifi %VALIDATE%==yes  IPOLREQ_Y(POLAREA,POLICY)
$ifi %VALIDATE%==yes+ VQPOLEQFUEL(POLAREA,POLICY,'IPLUS')- VQPOLEQFUEL(POLAREA,POLICY,'IMINUS')

        =E=
$ifi %VALIDATE%==yes    SUM((G,IA,IS3,T)$(POLTECH(POLICY,G) and IPOLAREAGEO(POLAREA,IA) and (IAGK_Y(IA,G) or IAGKN(IA,G
$ifi %VALIDATE%==yes        IHOURSINST(IS3,T)*IOF3P6*( VGF_T(IA,G,IS3,T)$IAGK_Y(IA,G) + VGFN_T(IA,G,IS3,T)$IAGKN(IA,G))

$ifi %VALIDATE%==no SUM((G,IA,IS3,T)$(POLTECH(POLICY,G) and IPOLAREAGEO(POLAREA,IA) and (IAGK_Y(IA,G) or IAGKN(IA,G))),
$ifi %VALIDATE%==no IHOURSINST(IS3,T)*( VGF_T(IA,G,IS3,T)$IAGK_Y(IA,G) + VGFN_T(IA,G,IS3,T)$IAGKN(IA,G)))
```

E.3 NBG_data.inc

Here are the data belonging to biogas add-on.

```



*=======================
*DATA
*======================

scalar TargetBG;
TargetBG = 1;
scalar TargetBGU;
TargetBGU = 1;


*==============================================================================
* System specific Assignments
*==============================================================================

*------------------------------------------------------------------------------------------------------------------------------------
* FLOW BALANCE (Technology operation conditions (relative))
*------------------------------------------------------------------------------------------------------------------------------------
Table       FB(AAA,GGG,io,e)
*                                        [MWh/h]   [MWh/h]   [MWh/h]   [MWh/h]        [ton/h]  [MWh/h]
                                         power     heat      biogas    Biogas_net      biomass  steam
hydrogen
DK_MA_Holst.biogasplant.in               0         0         1         0               0
0       0
DK_MA_Holst.biogasplant.out              0         0         1         0               0
0       0
DK_MA_Holst.BiogasUpg-AM-10-30.in        0.014     0         1         0               0
0       0
DK_MA_Holst.BiogasUpg-AM-10-30.out       0         0         0         0.944           0
0       0
DK_MA_Holst.BiogasPlant-MAN-10-30.in     0         0         0         0               5.228
0       0
DK_MA_Holst.BiogasPlant-MAN-10-30.out    0         0         1         0               0
0       0
DK_MA_Holst.BiogasPlant-CROPS-10-30.in   0         0         0         0               1.240
0       0
DK_MA_Holst.BiogasPlant-CROPS-10-30.out  0         0         1         0               0
0       0
DK_MA_Holst.biogasupg.in                 0         0         0         1               0
0       0
DK_MA_Holst.biogasupg.out                0         0         0         1               0
0       0
```

```
DK_MA_Holst.SOEC.in                     1.083     0         0         0                0
0.1746  0
DK_MA_Holst.SOEC.out                    0         0.166     0         0                0
0       1
DK_MA_Holst.Methanator.in               0         0         0.650     0                0
0       0.424
DK_MA_Holst.Methanator.out              0         0         0         1                0
0.074   0
;


*-----------------------------------------------------------------------------------------------------------------
* FLOW BALANCE (Transmissions)
*-----------------------------------------------------------------------------------------------------------------
Table       FLW1(AAA,GGG,IGGGALIAS,e)
                                                                  power     heat      biogas
Biogas_net       biomass
DK_MA_Holst.net.BiogasPlant-CROPS-10-30
1
DK_MA_Holst.net.BiogasPlant-MAN-10-30
1
DK_MA_Holst.BiogasPlant-MAN-10-30.biogasplant                                          1
DK_MA_Holst.BiogasPlant-CROPS-10-30.biogasplant                                        1
DK_MA_Holst.biogasplant.net                                                            1
DK_MA_Holst.biogasplant.BiogasUpg-AM-10-30                                             1
*DK_MA_Holst.biogasplant.Biogas-Industryheat-10-30                                     1
DK_MA_Holst.biogasplant.BiogasSto-10-30                                                1
*                                                                 power     heat      biogas
Biogas_net       biomass
DK_MA_Holst.BiogasSto-10-30.net                                                        1
DK_MA_Holst.BiogasSto-10-30.BiogasUpg-AM-10-30                                         1
*                                                                 power     heat      biogas
Biogas_net       biomass
DK_MA_Holst.net.BiogasUpg-AM-10-30                                1
DK_MA_Holst.BiogasUpg-AM-10-30.BiogasUpg
1
DK_MA_Holst.BiogasUpg.net
1
*                                                                 power     heat      biogas
Biogas_net       biomass
*DK_MA_Holst.Biogas-Industryheat-10-30.net                                              1
;

Table       FLW2(AAA,GGG,IGGGALIAS,e)
                                                                  power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.net.BiogasPlant-CROPS-10-30
1
DK_MA_Holst.net.BiogasPlant-MAN-10-30
1
DK_MA_Holst.BiogasPlant-MAN-10-30.biogasplant                                          1
DK_MA_Holst.BiogasPlant-CROPS-10-30.biogasplant                                        1
DK_MA_Holst.biogasplant.net                                                            1
DK_MA_Holst.biogasplant.BiogasUpg-AM-10-30                                             1
DK_MA_Holst.biogasplant.BiogasSto-10-30                                                1
*                                                                 power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.BiogasSto-10-30.net                                                        1
DK_MA_Holst.BiogasSto-10-30.BiogasUpg-AM-10-30                                         1
*                                                                 power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.net.BiogasUpg-AM-10-30                                1
DK_MA_Holst.BiogasUpg-AM-10-30.BiogasUpg
1
DK_MA_Holst.BiogasUpg.net
1
*                                                                 power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.net.SOEC                                              1
1
DK_MA_Holst.SOEC.Net                                                        1
DK_MA_Holst.SOEC.hydrogenstorage
1
```

```
*                                                                    power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.hydrogenstorage.methanator
1
*                                                                    power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.BiogasSto-10-30.methanator                                                  1
*                                                                    power     heat      biogas
Biogas_net       biomass steam   hydrogen
DK_MA_Holst.methanator.Net
1
DK_MA_Holst.methanator.BiogasUpg
1
DK_MA_Holst.methanator.SOEC
1
;

Parameter FLW(AAA,GGG,IGGGALIAS,e);

$ifi %NEWBIOGAS%==yes
$ifi %SOECUP%==no FLW(AAA,GGG,IGGGALIAS,e)=FLW1(AAA,GGG,IGGGALIAS,e);

$ifi %NEWBIOGAS%==yes
$ifi %SOECUP%==yes FLW(AAA,GGG,IGGGALIAS,e)=FLW2(AAA,GGG,IGGGALIAS,e);


$ifi %VALIDATE%==yes FLW('DK_SA_E_BG',GGG,IGGGALIAS,e)$(FLW('DK_MA_Holst',GGG,IGGGALIAS,e))= yes ;
$ifi %VALIDATE%==yes FB('DK_SA_E_BG',GGG,io,e)=FB('DK_MA_Holst',GGG,io,e);

$ifi %VALIDATE%==yes FLW('DK_MA_Holst',GGG,IGGGALIAS,e)= no ;
$ifi %VALIDATE%==yes FB('DK_MA_Holst',GGG,io,e)=no;

$ifi %VALIDATE%==no FLW(nbg_dk,GGG,IGGGALIAS,e)$(FLW('DK_MA_Holst',GGG,IGGGALIAS,e))= yes ;
$ifi %VALIDATE%==no FB(nbg_dk,GGG,io,e)=FB('DK_MA_Holst',GGG,io,e);

display FLW;

display FB;


* OMONEY EUR90/? ,TJEK VÆRDIER!
Table NBGOMVAR(GGG,e)
                                  power     heat      biogas     Biogas_net       biomass hydrogen
steam
BiogasPlant                                           0          0                        0
BiogasPlant-MAN-10-30                                 31         0                        0
BiogasPlant-CROPS-10-30                               32         0                        0
BiogasSto-10-30                                       0          0                        0
BiogasUpg-AM-10-30                                    0          0                        0
NET                                                   0          0                        0
methanator                                            0          0                        0
SOEC                                                  0          0                        0
;

parameter CAP(g,l);

CAP('BiogasPlant-MAN-10-30','min') =0.99;

$ifi %SOECUP%==yes CAP('methanator','min') =0.2;


* Unit capacities
parameter GRAD(g);

GRAD('BiogasPlant-CROPS-10-30')= 0.00297619;
* 1 til 14 dage

SCALAR IOF3     'Multiplier 3'        /3/;
SCALAR IOF0P089     'Multiplier 3'        /0.89/
```

```
Table FLOWP(YYY,AAA,GGG,IGGGALIAS,e)

*Biomass is euro90/ton, Biogas_net is NG price plus co2 price in euro90/mwh
/*                                                                  BIOMASS
2014 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2015 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2016 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2017 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2018 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2019 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2020 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2021 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2022 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2023 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2024 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2025 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2026 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2027 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2028 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2029 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2030 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2031 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2032 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2033 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2034 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2035 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2036 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2037 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2038 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2039 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2040 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2041 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2042 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2043 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2044 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2045 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2046 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2047 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2048 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2049 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3
2050 .    DK_MA_HOLST  .    net  .    BiogasPlant-CROPS-10-30 18.3

*+                                                            BIOMASS
2014 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2015 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2016 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2017 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2018 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2019 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2020 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2021 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2022 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2023 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2024 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2025 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2026 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2027 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2028 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2029 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2030 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2031 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2032 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2033 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2034 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2035 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2036 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2037 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2038 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2039 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2040 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2041 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2042 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2043 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
```

```
2044 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2045 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2046 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2047 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2048 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2049 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
2050 .    DK_MA_HOLST  .    net  .    BiogasPlant-MAN-10-30 2.7
*/
                                                  BIOGAS_NET
2014 .    DK_MA_HOLST  .    BIOGASUPG .    net  -22.68
2015 .    DK_MA_HOLST  .    BIOGASUPG .    net  -23.47
2016 .    DK_MA_HOLST  .    BIOGASUPG .    net  -23.55
2017 .    DK_MA_HOLST  .    BIOGASUPG .    net  -23.63
2018 .    DK_MA_HOLST  .    BIOGASUPG .    net  -23.72
2019 .    DK_MA_HOLST  .    BIOGASUPG .    net  -23.84
2020 .    DK_MA_HOLST  .    BIOGASUPG .    net  -24.32
2021 .    DK_MA_HOLST  .    BIOGASUPG .    net  -24.53
2022 .    DK_MA_HOLST  .    BIOGASUPG .    net  -25.09
2023 .    DK_MA_HOLST  .    BIOGASUPG .    net  -25.3
2024 .    DK_MA_HOLST  .    BIOGASUPG .    net  -25.86
2025 .    DK_MA_HOLST  .    BIOGASUPG .    net  -26.43
2026 .    DK_MA_HOLST  .    BIOGASUPG .    net  -26.63
2027 .    DK_MA_HOLST  .    BIOGASUPG .    net  -26.84
2028 .    DK_MA_HOLST  .    BIOGASUPG .    net  -27.41
2029 .    DK_MA_HOLST  .    BIOGASUPG .    net  -27.61
2030 .    DK_MA_HOLST  .    BIOGASUPG .    net  -28.18
2031 .    DK_MA_HOLST  .    BIOGASUPG .    net  -28.38
2032 .    DK_MA_HOLST  .    BIOGASUPG .    net  -28.59
2033 .    DK_MA_HOLST  .    BIOGASUPG .    net  -29.15
2034 .    DK_MA_HOLST  .    BIOGASUPG .    net  -29.36
2035 .    DK_MA_HOLST  .    BIOGASUPG .    net  -29.92
2036 .    DK_MA_HOLST  .    BIOGASUPG .    net  -29.92
2037 .    DK_MA_HOLST  .    BIOGASUPG .    net  -30.28
2038 .    DK_MA_HOLST  .    BIOGASUPG .    net  -30.28
2039 .    DK_MA_HOLST  .    BIOGASUPG .    net  -30.28
2040 .    DK_MA_HOLST  .    BIOGASUPG .    net  -30.64
2041 .    DK_MA_HOLST  .    BIOGASUPG .    net  -30.64
2042 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31
2043 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31
2044 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31
2045 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31.36
2046 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31.36
2047 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31.72
2048 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31.72
2049 .    DK_MA_HOLST  .    BIOGASUPG .    net  -31.72
2050 .    DK_MA_HOLST  .    BIOGASUPG .    net  -32.08

;

*2020 .    DK_MA_HOLST 662734

Table BIOGASREQ(YYY,AAA,FFF) 'yearly required Biogas use in area DK_MA_holst'
*Mwh/year
                        BIOGAS
2014 .    DK_MA_HOLST 542348
2015 .    DK_MA_HOLST 562413
2016 .    DK_MA_HOLST 582477
2017 .    DK_MA_HOLST 602541
2018 .    DK_MA_HOLST 622606
2019 .    DK_MA_HOLST 642670
2020 .    DK_MA_HOLST 605342
2021 .    DK_MA_HOLST 706916
2022 .    DK_MA_HOLST 751099
2023 .    DK_MA_HOLST 795281
2024 .    DK_MA_HOLST 839463
2025 .    DK_MA_HOLST 883645
2026 .    DK_MA_HOLST 927828
2027 .    DK_MA_HOLST 972010
2028 .    DK_MA_HOLST 1016192
2029 .    DK_MA_HOLST 1060375
2030 .    DK_MA_HOLST 1104557
2031 .    DK_MA_HOLST 1148739
2032 .    DK_MA_HOLST 1192921
```

```
2033 .    DK_MA_HOLST 1237104
2034 .    DK_MA_HOLST 1281286
2035 .    DK_MA_HOLST 1325468
2036 .    DK_MA_HOLST 1325468
2037 .    DK_MA_HOLST 1325468
2038 .    DK_MA_HOLST 1325468
2039 .    DK_MA_HOLST 1325468
2040 .    DK_MA_HOLST 1325468
2041 .    DK_MA_HOLST 1325468
2042 .    DK_MA_HOLST 1325468
2043 .    DK_MA_HOLST 1325468
2044 .    DK_MA_HOLST 1325468
2045 .    DK_MA_HOLST 1325468
2046 .    DK_MA_HOLST 1325468
2047 .    DK_MA_HOLST 1325468
2048 .    DK_MA_HOLST 1325468
2049 .    DK_MA_HOLST 1325468
2050 .    DK_MA_HOLST 1325468

;


$ifi %test%==yes BIOGASREQ('2020','DK_SA_E_BG','BIOGAS')= 100392;
*Skal være i GJ per år


FLOWP('2020',nbg_dk,'net','BiogasPlant-CROPS-10-30','BIOMASS') = 18.3;

FLOWP('2020',nbg_dk,'net','BiogasPlant-MAN-10-30','BIOMASS') = 2.7;

FLOWP('2020',nbg_dk,'BIOGASUPG','net','BIOGAS_NET') = -24.32;

FLOWP(YYY,nbg_dk,'net','BiogasPlant-CROPS-10-30','BIOMASS') = FLOWP(YYY,'DK_MA_HOLST','net','BiogasPlant-CROPS-10-30',

FLOWP(YYY,nbg_dk,'net','BiogasPlant-MAN-10-30','BIOMASS') = FLOWP(YYY,'DK_MA_HOLST','net','BiogasPlant-MAN-10-30','BIO

FLOWP(YYY,nbg_dk,'BIOGASUPG','net','BIOGAS_NET') = FLOWP(YYY,'DK_MA_HOLST','BIOGASUPG','net','BIOGAS_NET');


Table BIOGASPOTMAN(YYY,FFF,AAA)

*BIOGAS FROM MANURE POTENTIAL IN TJ FOR EACH DH AREA

                 DK_CA_Esb DK_CA_Hern DK_CA_Kal DK_CA_KBH DK_CA_Odense DK_CA_Randers DK_CA_Roenne DK_CA_TVIS DK_CA_Aab
2014 .    biogas
2015 .    biogas
2016 .    biogas
2017 .    biogas
2018 .    biogas
2019 .    biogas
2020 .    biogas 74.85     45.15      21.35     7.5       25.45        15.45         19.2
64.5       38.1      17.85     29.6         0.15     49.95           28.65        2.3       45.7
36.65       17.35         3.1            19.45      24.65         48.35        10.3           35.45
13.75         20.15        13.9            8.8            19.45         8.8        10.3
5.2             10.3         28.8           24.55       42.9       215.9          98.45
23.05          83.15         71.7          252.4      282.1      1095.2         912.2         280.25
157.85         608.8         912.2
2021 .    biogas
2022 .    biogas
2023 .    biogas
2024 .    biogas
2025 .    biogas
2026 .    biogas
2027 .    biogas
2028 .    biogas
2029 .    biogas
2030 .    biogas
2031 .    biogas
2032 .    biogas
2033 .    biogas
2034 .    biogas
2035 .    biogas 149.7     90.3       42.7      15        50.9         30.9          38.4
129        76.2      35.7      59.2         0.3      99.9            57.3         4.6       91.4
```

```
73.3        34.7          6.2            38.9       49.3          96.7          20.6           70.9
27.5          40.3         27.8            17.6            38.9          17.6       20.6
10.4            20.6         57.6            49.1        85.8        431.8           196.9
46.1           166.3         143.4         504.8      564.2      2190.4         1824.4        560.5
315.7          1217.6        1824.4

;

scalar testtest;
testtest= sum(aaa,BIOGASPOTMAN('2020','biogas',AAA));

display testtest;

* In TJ
Table BIOGASPOTCROPS(YYY,FFF)
     BIOGAS
2020 3700
2035 12240

;
```

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