AALBORG UNIVERSITY
STUDENT REPORT

DISTRICT HEATING IN NORWAY

An analysis of shifting from individual electric heating to district heating

Master's Thesis

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June 2017

Title: District Heating in Norway – An analysis of shifting from individual electric heating to district heating
Semester description: 4th Semester, MSc in Sustainable Energy Planning and Management
School: School of Architecture, Design and Planning
Semester theme: Master's Thesis
Project Period: 01.02.2017 – 02.06.2017
ECTS: 30

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Pages: 141
(including appendices)

Abstract:

Norway has in recent years often been referred to as the future "green battery" of the European energy system due to its abundant hydro resources. Already today, Norway functions as a "virtual green battery" by importing excess electricity from Europe and exporting electricity when Europe needs it. The Norwegian energy system is largely based on electricity, including the heating sector, which could potentially limit the export capacity.

In this master thesis it was investigated how a shift from individual electric heating to DH would affect the operation of the Norwegian energy system and which potential barriers could be identified for such a shift.

Using the simulation tool EnergyPLAN, the operation of the Norwegian energy system was simulated for a Reference scenario and four designed DH scenarios based on DH production from biomass (25% shift) and HP's (25%, 50%, 100% shift).

It was concluded that a shift from DH would affect the total electricity demand in the Norwegian system, which in turn would free up potential flexible production capacity that could contribute positively to Norway's role as a "virtual green battery" of Europe. It was, however, also concluded that the dammed hydro power did not respond to the change in electricity demand, due to how this was modelled in EnergyPLAN. It is expected that the demand response would be better in reality, and further investigation of this is therefore needed to conclude on the flexibility within the Norwegian energy system.

Barriers were identified in the organisational framework for DH and in the existing infrastructure for DH. It was concluded that the most significant barrier is the lack of infrastructure for waterborne heating systems in the existing building mass, as this would make a shift to DH a large one time expenditure for potential customers.

Preface

This is the resulting master thesis from the 4th semester in the Master's programme of Sustainable Energy Planning and Management at Aalborg University. The master thesis has been carried out in the spring semester 2017, with the semester theme: Master's Thesis.

Acknowledgements

We would like to express our sincere gratitude to our supervisor Assistant Professor Peter Sorknæs for his guidance throughout this master thesis. We thank him for his encouragement and advices that he provided us throughout this semester. He has always made himself available to respond to all of the questions that we had for him and we are grateful to have had him as a supervisor.

We would also like to thank the following people for their provision of valuable insight and data through the master thesis:

- Heidi Juhler - Norsk Fjernvarme
- Anders Andersen and Christian Frandsen - EMD
- Even Loe and Erlend Fossøy - Statkraft
- Åmund Utne and Kristin Bløtekjær - Statkraft Varme
- Roy Ulvang - Avfall Norge
- Eirik Leknes

Lastly,

I, Kristina Bozhkova would like to thank my partner Sissi for her love and the moral support provided throughout this master thesis. I would also like to thank my thesis partner, Kristine Askeland for her hard work on this master thesis and for always making me laugh.

I, Kristine Askeland, would first and foremost like to thank my parents for supporting me through my 7-year long journey through university. Furthermore, I would like to thank my thesis partner, Kristina Bozhkova for all her hard work on both the thesis and on making our days of writing filled with laughter.

Reading Guidelines

All chapters, sections, tables and figures are numbered according to their placement in the report as [chapter.chronological number.]. To exemplify - the first figure in chapter 2 is labelled Figure 2.1. Both figures and tables are complimented with captions containing explanatory text. Sections are labelled [chapter.section.subsection].

References used in this master thesis are according to the Harvard referencing system where references through the report are shown as [Author, Year]. N.D. is sometimes used instead of year, when it was not possible to determine the exact year of the publication. References placed after a dot ". [Author, Year]" are used when the reference refers to an entire paragraph or up to the previous reference in the paragraph. eferences placed before a dot of a sentence, "[Author, Year]." are considered to be referencing only this sentence. Active references are also used, and are shown as Author, Year. The full reference list can be found on page 99. In the electronic version of the report, clicking the references in through the report leads the reader to the relevant entry in the reference list.

A list of acronyms and units used through the report can be found on page iii.

Nomenclature

Acronyms

Acronym	Description
CEEP	Critical excess electricity production
CHP	Combined heat and power
CO_2	Carbon dioxide
COP	Coefficient of performance
DH	District heating
EEA	European economic area
EFTA	European free trade association
EU	European Union
EV	Electric vehicles
GHG	Greenhouse gas
HP	Heat pump
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IEA	International energy agency
NOK	Norwegian krone
NVE	Norges vassdrags- og energidirektorat (Norwegian Water Resources and Energy Directorate)
PES	Primary energy supply
RE	Renewable energy
REMODECE	Residential Monitoring to Decrease Energy Use and Carbon Emissions in Europe
RES	Renewable energy source
SINTEF	Stiftelsen for industriell og teknisk forskning (The Foundation for Scientific and Industrial Research)
SSB	Statistisk sentralbyrå (Statistics Norway)
TSO	Transmission system operator
UK	United Kingdom
VAT	Value-added tax

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Introduction 1

There is widespread evidence that the increase of CO_2 and other greenhouse gasses in the atmosphere are caused by anthropogenic activities and contribute to global warming [IPCC, 2014]. A large share of the emissions are caused by combustion of fossil fuels in the energy sector [Royal Society and National Academy of Sciences, 2014]. The European Union has taken measures towards decreasing the level of GHG emissions and is countering climate change [European Commission, 2011]. In the following sections the European energy system and the future transition of the system is outlined.

1.1 Energy system of the EU

The energy system of the EU is still very dependent on fossil fuels within all energy sectors. In 2013 a total of 73.8% of the total energy consumption in the EU came from fossil fuels, RES accounted for 11.8% and 13.6% was nuclear power. Figure 1.1 illustrates the net imports of the EU from 1990 to 2013 by fuel. It can be seen from the figure that the import of fossil fuels as a whole has increased through the years, although the import of all products from 2005 to 2013 remained relatively steady. All in all, 53.2% of the consumed fossil fuels within the EU in 2013 were imported. [European Environment Agency, 2015]

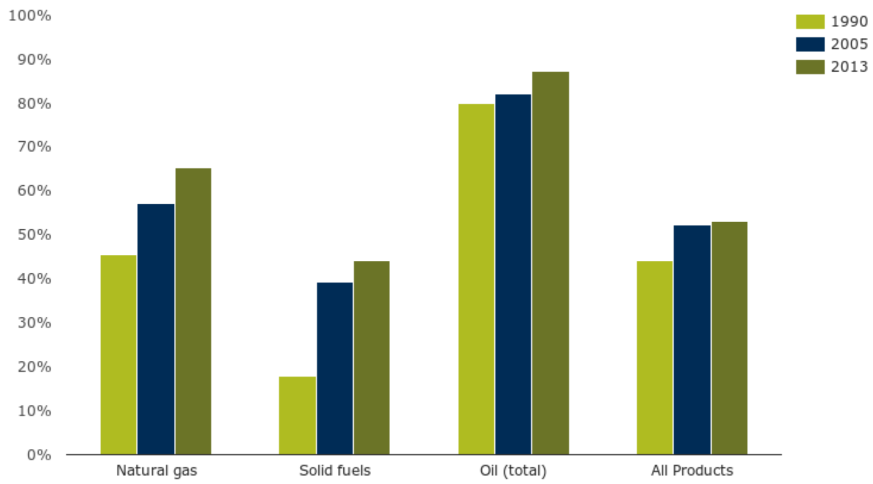


Figure 1.1: Net imports by fuel in the EU. [European Environment Agency, 2015]

More than half of the total annual consumption of energy in the EU is used for heating and cooling; approximately 68% of all oil and gas imports are used for this purpose. [European Commission, 2016b] Security of supply is vital for the European economy. Particularly the

European heating sector is highly dependent on gas imports and is therefore vulnerable to threats to the security of gas supply. [European Environment Agency, 2015]

1.2 The transition of the European energy system

The European energy system, which traditionally has been highly dependent on imported fossil fuels, is currently in transition [European Environment Agency, 2015]. By 2050, the EU has a goal of reducing GHG emissions in Europe by 80-95%. To reach this long term goal, several strategies with shorter time spans have been made, setting intermediate goals for both 2020 and 2030. [European Commission, 2011]

The EU 2020 energy strategy contains the three following goals [European Commission, 2010]:

- 20% decrease in GHG compared to 1990 levels
- 20% increase of the share of RE
- 20% increase of energy savings

In addition to these goals, a 10% share of RES in the transport sector is to be reached by 2020 in all EU countries [European Commission, 2010].

A transition from a traditional fossil fuel based system towards a system based on RES, will generate a need for new balancing options. Whereas the electricity production traditionally is controlled to fit the demand, a RES system's input cannot necessarily be controlled in the same manner, depending on the technology. Technologies such as wind turbines and PV will produce fluctuating energy, thus not necessarily following the demand. This creates the need for flexible energy consumption for example through electricity storage, expansion of the interconnected network of Europe, flexible units, conversion to other forms of energy and integration of the different energy sectors.

Increasing the share of district heating and cooling in the European energy system could also help increase the flexibility of the future European energy system by functioning as flexible energy consumption. Additionally, it could help lower the electricity demand for heating and cooling and make heating and cooling more reliable and more affordable for consumers. [European Commission, 2016a] In February 2016 the European Commission [2016b] has recognised the need to develop the first "EU Heating and Cooling strategy". One of the strategy's objectives is establishing a cooperation between the electricity and heating and cooling sector. This could ease the decarbonising vision of the EU energy strategies for the future by utilising more renewables to the heating and cooling sector. [European Commission, 2016b] Furthermore, DH systems are able to integrate electricity coming from RES and heat from solar and geothermal thermal energy. DH systems are also able to utilise excess heat from industries and interactions between waste-to-energy and DH could potentially be a secure way of phasing out fossil fuels in the future. This way the DH sector could provide flexibility in the European system by storing heat in thermal storages. [European Commission, 2016a]

1.3 Norway's role in the transition of the European energy system

Another already existing options for increasing the flexibility within the European energy system is through the utilisation of Norwegian hydro power capacity. Half of Europe's stored hydro capacity is located in Norway, and could provide a cheap, low-carbon solution to future European balancing needs. [Piria and Junge, 2013] Norway has already controllable hydro power [Statnett, 2012], which could be used to add flexibility to the European energy system. This is often referred to as Norway functioning as a 'green battery' of Europe.

If Europe is to utilise Norway's flexible electricity production and use Norway as a 'green battery', it has to be taken into account that the Norwegian energy system is highly based on electricity, including both the electricity and heating sector IEA [2015]. The electricity production in Norway is almost entirely based on hydro power, which despite being highly controllable, also depends on the water inflow to the hydro power reservoirs. Basing the heating sector on electricity, in particular dammed hydro power, makes the heating sector more vulnerable to cold winters in dry years. Furthermore, a large electricity consumption within the country may decrease the possibilities of utilising Norwegian hydro power resources as balancing power for Europe. One way to do this shift is by following the EU Heating and Cooling strategy and looking into increasing of the DH sector in the country. In order to investigate a potential shift from individual electric heating to DH, a further investigation of the Norwegian energy system, with specific focus on the Norwegian heating sector, is needed. [Norwegian ministry of petroleum and energy, 2015]

Problem analysis 2

In chapter 1, it was discussed whether the highly electrified heating sector in Norway may be a limiting factor to the idea of utilising Norwegian hydro power for balancing in the European electricity sector. Questions were raised whether a change from individual electric heating to DH could have an effect on the flexibility of the Norwegian electricity sector and energy system. The aim of the following section is to give an overview of the Norwegian energy sector, with specific focus on the Norwegian heating sector, and further exploit the concept of using Norway as a 'green battery' for Europe.

2.1 Norway's connection to the EU

Norway is per march 2017 not a member of the EU. However, Norway is connected to the EU through several relations. Through the EEA agreement, Norway and the other EFTA states are equal partners, on the same terms as other EU member states, in the EU internal market. Through this agreement Norway also cooperates with the EU in other areas such as research and development, the environment, consumer protection, education, social policy, tourism and culture. Norway and the other EFTA states are also able to participate in various EU programmes and, through provisions in the agreement, activities of a number of EU agencies. [The Norwegian Mission to the EU, 2016] Other fields of cooperation between Norway and the EU include justice and home affairs, energy and climate, research and education, maritime affairs, and fisheries. [The Norwegian Mission to the EU, 2016]

As a member of the EEA, Norway is committed through the Renewable Energy Directive (DIRECTIVE 2009/28/EC), to the EU 2020 goals. Through this, Norway is also required to reach a RES share of 67.5% in the gross final energy production by 2020. [Regjeringen, 2012]

2.2 Norway as a 'green battery'

Within the energy community, Norway has often, in recent years, been referred to as a possible 'green battery' for Europe because of it's large hydro power potential. Per march 2017, almost half of Europe's hydro reservoir capacity is located in Norway [Statkraft, 2009]. The EU hopes that this potential can contribute as battery capacity in the future energy system of Europe [Gullberg, 2013].

According to Gullberg [2013] Norwegian decision-makers and interest groups perceive the green battery concept differently from other European actors. The talk in Europe has often been surrounded around pumped-storage hydro power as a mean to store electricity in the form of added hydro power potential in times where there is excess electricity in the European electricity system. The Norwegian interpretation of the green battery concept is to utilise imported European wind power, or other fluctuating electricity production, when it is available and export hydro power when the production from wind turbines in Europe is low. [Gullberg, 2013]

It could be argued, that Norway is already to some extent functioning as a 'virtual green battery' for Europe. The Norwegian TSO Statnett imports cheap electricity from surrounding countries when there is an excess production, typically when there is a lot of wind or solar production, and uses this instead of Norwegian hydro power. In return, electricity produced by Norwegian hydro power production is exported to neighbouring countries on demand. [Stone, 2015]

According to Gullberg [2013] pumped-storage hydro face both political, economical and technical challenges in today's market. In short term, it is therefore more likely that Norway would only function as a 'virtual green battery'. In order for Norway to function as a 'virtual green battery', a certain flexibility within the Norwegian energy system is needed in order to respond to changes in demand and production in Europe. In the introduction, the idea of shifting electricity used for heating to DH was introduced as a possibility to reduce electricity consumption and consequently increase the available flexible production capacity that can be utilised for export to Europe.

2.3 Norwegian energy system

The Norwegian energy system is heavily electrified and according to IEA [2015] the electricity consumption compared to the IEA average is high - 23.11 MWh per capita compared to 8.72 MWh per capita as of 2015. One of the reasons behind this could be that in Norway, space heating in households and oil and gas for heating in industries, are replaced with electricity. In the same year the electricity production had an RES share of 98% compared to an IEA average of 24%. [IEA, 2015]

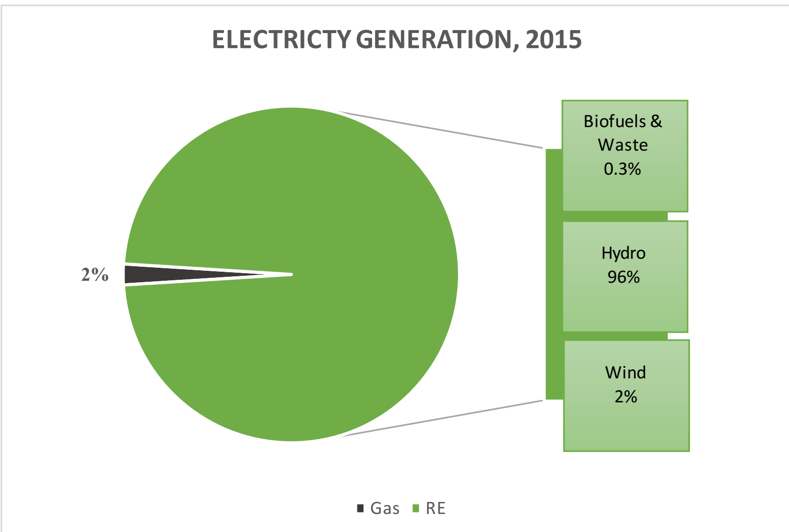


Figure 2.1: Electricity generation of Norway. Based on figure by IEA [2015].

Figure 2.1 illustrates the electricity mix of the country, which consists of mainly hydro power with a share of 96% of the total electricity production. The country's enormous hydro power resources play a important role in delivering electricity for all purposes, including heating. [IEA, 2015]

The total energy consumption in Norway in 2015 was 166 384 GWh, of which 67% was electricity [SSB, N.D.]. The energy consumption from 2007 to 2015 can be seen graphically depicted in figure 2.2.

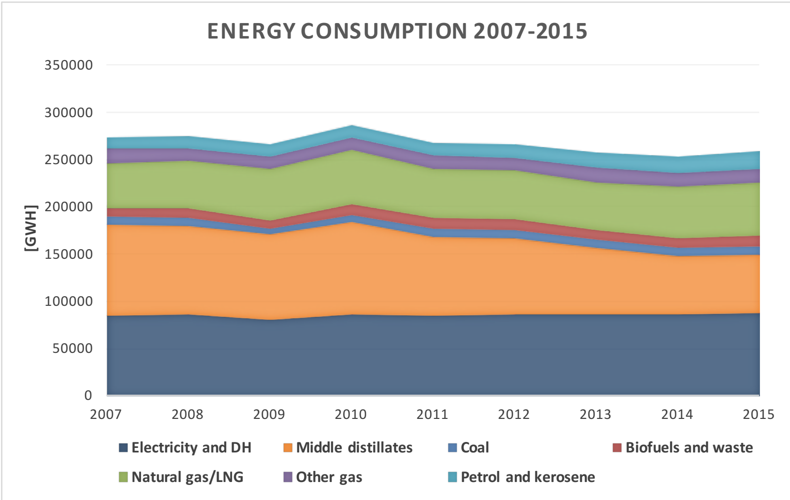


Figure 2.2: Energy consumption divided on different energy sources in Norway from 2007 to 2015. Own figure based on data from SSB [N.D.].

In figure 2.2 it can be seen that the energy consumption varies from year to year, with a notable peak in 2010. The peak is found in the use of middle distillates such as jet fuel and diesel, and it is mainly found in the transport sector. It is difficult to say what caused this peak in the transport sector in 2010, but it must be noted that 2010 was a cold year [Yr, N.D.]. The total energy consumption in this year may therefore be higher than in warmer years. From the figure it is also seen that the electricity consumption varies from year to year and does not show a downward or upward trend. The variation in the electricity consumption could be due to the high share of electric heating in Norway, which naturally increases the consumption in colder years, as the need for heating is higher. It can also be seen that the use of middle distillates is decreasing, which may be partly related to the phasing out of oil in the heating sector towards 2020 when a national ban on oil boilers for heating is expected [Regjeringen, 2016a]. It could potentially also be related to a decreased use of oil in industry.

2.3.1 Electrification of transport and the oil and gas sector

As was seen in figure 2.1 the electricity production is based mainly on renewable sources and consequently the CO_2 emissions from the electricity sector are low. However, Norway still has CO_2 emissions from other sectors, mainly from the transport and industry sector. [SSB, 2016a]

Figure 2.3 shows the CO_2 emissions from different sectors in 2015.

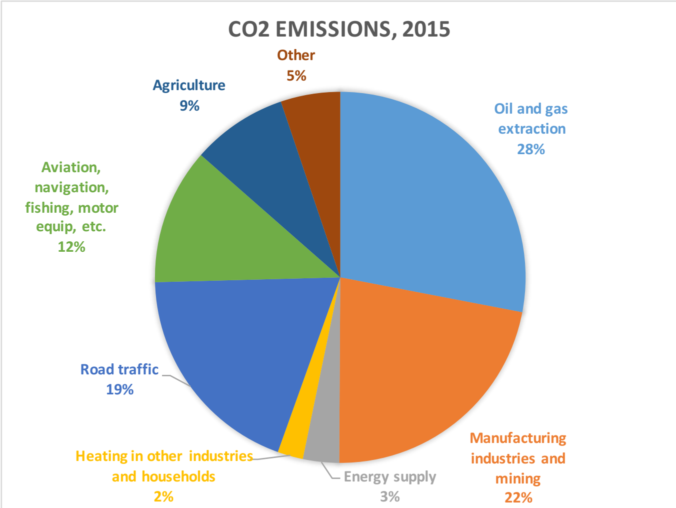


Figure 2.3: CO_2 emissions of Norway in 2015. Own figure based on data from SSB [2016a].

Norwegian greenhouse gas emissions in 2015 amounted to a total of 53.9 Million tonnes CO_2 equivalents. Three sectors stood for almost 70% of the emissions seen in figure 2.3: the largest share of CO_2 emissions is found in the offshore oil and gas extraction sector with 28%, followed by 22% from manufacturing industry and mining, and 19% from road traffic. [SSB, 2016a].

In 2014, the Norwegian Government decided that part of the Norwegian offshore oil and gas industry, was to be electrified, specifically the area Utsira High. This decision is justified by the need to reduce CO_2-emissions from the extraction of oil and gas on the Norwegian continental shelf, which are expected to decrease when using clean electricity from hydro power plants instead of using gas turbines on site. This decision has been met with both support and criticism, but the reality is that the development will start in 2019 and is expected to be finished in 2022. [UngEnergi, 2016] A consequence of the electrification of the offshore oil and gas sector will necessarily be a higher electricity demand from renewable energy sources, mainly hydro power.

The road traffic sector is also in transition towards an electrification of passenger cars. As was stated in section 1.2, the EU 2020 goals include reaching an RES share of 10% in the transport sector by 2020. The electrification of road traffic can contribute to reaching this share, as long as the electricity used is renewable.

In 2015, the share of electric cars in Norway was 2.6% of the total number of registered vehicles. The actual number of electric cars increased by 79% from the year before. [SSB, 2016b] Of newly registered cars in 2016, almost 40% were electric [The Guardian, 2017]. This indicates, that for the moment being, electric cars are increasingly popular as an alternative to traditional fossil fuelled cars. The increase in electric cars does, however, not necessarily indicate that there is a will in the population to be more climate friendly. The increase could very possibly be due to favourable economic conditions for electric vehicles in Norway. Until 2020 electric vehicles are exempted from VAT and the one time vehicle tax based on weight and emissions [Valle, 2016]. Electric vehicles are also guaranteed minimum half price on national ferries and in congestion zones [Valle, 2016]. Local authorities can also give electric vehicles even further economic advantages, such as free parking [Valle, 2016]. As long as the economic incentives for electric vehicles continue, there is reason to believe that the share of electric cars in Norway will increase in the years to come, and consequently increase the electricity demand in the road transport sector.

In general, an electrification of parts of the traditionally fossil fuelled based energy sector, is expected to cause an increase in the national electricity consumption, unless the same amount of electricity savings are implemented. It is also reasonable to believe that the electricity demand profile will change, and in local areas the needed electric capacity could increase.

2.3.2 Heating sector in Norway

The heating sector in Norway is mainly based on electricity [Norwegian ministry of petroleum and energy, 2015] and could be roughly divided into households, service sector and industry as main consumers. Figure 2.4 illustrates the main heating sources used in households in 2012.

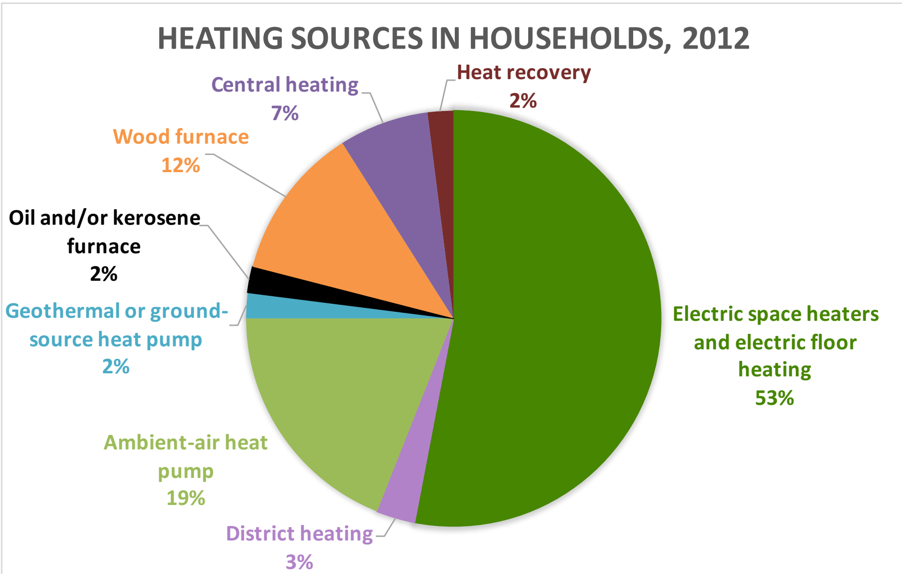
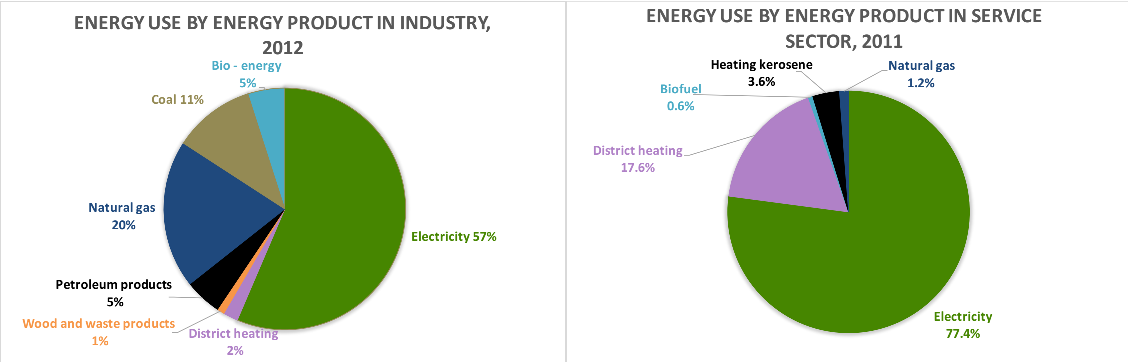


Figure 2.4: Main heating sources in households, Norway 2012. Own figure based on [SSB, N.D.].

From the figure it can be seen that more than half of the technologies used for heating purposes are electricity driven space and floor heaters (53%). The second largest heating source used in 2012, which accounted for 19%, was air-to-air heat pumps, which also use electricity. So in total, electric heating is the major heating source, followed by wood furnace and central heating. District heating accounted only for 3%.

Figure 2.5 illustrates the energy use by energy products in service and industry sectors.



(a) Industry (b) Service sector

Figure 2.5: Illustration of energy usage in industry and service sectors in Norway. Figure based on statistics from SSB [N.D.].

It can be seen from figure 2.5 that both sectors have a large electricity consumption - 77.4% and 53% in service and industry sectors, respectively. The district heating share in service buildings is the highest (17.6%) when compared to households (3%) and industry (2%). The use of fossil fuels is largest in industry. It is however unclear to what extent the distribution of these energy products in both service and industry are related to the heating sector. According to SSB [N.D.], a large share of the energy used in the service sector is due to heating needs. According to Regjeringen [2008] there are also no data on the exact need of heat in industry as some of the energy products used might be due to the need of heat for industry processes and not for space heating. In a report by Regjeringen [2008] it is estimated that around 51% out of the total energy consumption in industry was used for heating the industrial buildings and almost 70% out the heating demand for these buildings was delivered by electricity. It is clear that electricity plays a major role in the energy use of both service and industry sectors.

Based on figures 2.4 and 2.5 it can be concluded that the Norwegian heating sector is to a large extent based on individual electric heating. An increase in electricity consumption in both heat and transport sector, as explained in section 2.3.1, could potentially decrease the flexibility of the Norwegian energy system.

IEA/Nordic Council of Ministers [2016] suggest that an interaction between the electricity and district heating sectors could potentially increase the flexibility of energy systems. This will allow storage of excess electricity in the form of thermal energy, which could be utilised in district heating systems.

District heating in Norway

The expansion of district heating in Norway started as late as in the 1980's [Sandberg and Trømborg, 2016]. Traditionally, low electricity prices has made electric heating a natural source for heat in Norway, different from many of the neighbouring countries such as Sweden and Denmark [Sandberg and Trømborg, 2016].

The total gross production of district heating in 2015 was 5 444 GWh, of which a total of 4 831 GWh was delivered to consumers in households, service sector and industry [SSB, N.D.]. The district heating balance in 2015 can be seen in figure 2.6.

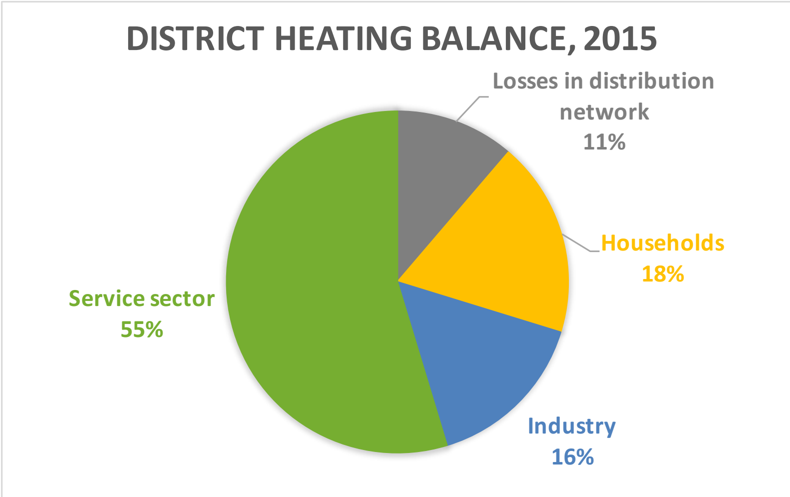


Figure 2.6: District heating balance in 2015. Own figure based on data from SSB [N.D.].

In figure 2.6 it can be seen that the largest share of district heating is delivered to the service sector, with a share of 55% of the gross production. Households and industry had shares of 18% and 16% respectively, while the distribution losses accounted for 11% of the gross production.

District heating is produced from several sources, and the mix of the DH production in 2015 can be seen in figure 2.7.

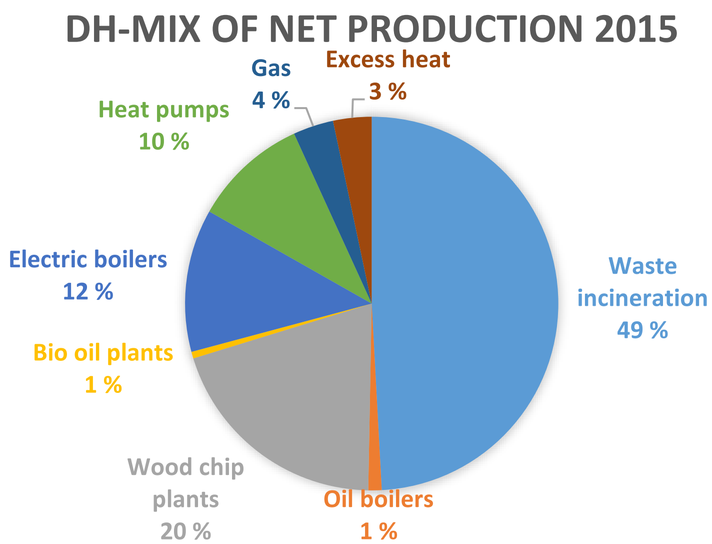


Figure 2.7: National mix of district heating production in 2015. Own figure based on data from SSB [N.D.].

From the figure, it can be seen that almost half of the DH produced in 2015 was from waste incineration. Other notable production shares are from wood chip plants, electric boilers and heat pumps.

According to statistics from SSB [N.D.] from 2006-2015, the share of waste incineration in the district heating mix has always been large - accounting to a minimum of 32% of the mix in all years - but has increased since 2011. The increased share of waste incineration in the DH-mix may be related to the national ban of disposal of waste to landfills in 2009, increasing the need for waste incineration [Aanensen and Fedoryshyn, 2014].

Statistics from SSB [N.D.] show that the average price of district heating, excluding VAT, in 2015 was 0.58 NOK/kWh. According to [Aanensen and Fedoryshyn, 2014] the price of district heating increased significantly from the late 1980's up until today. This could be related to an increase of fuel prices for district heating as well as a general increase in prices across all energy sectors [Aanensen and Fedoryshyn, 2014]. The price of district heating varies between the different DH-companies, but is strongly related to the electricity price. For buildings that are obligated to connect to the district heating system, the Norwegian Energy Law decides that the district heating price for these consumers cannot exceed the electricity price in their price area. [Aanensen and Fedoryshyn, 2014] In Norway, one of the reasons that the price of district heating is dependent on the electricity price is regulations preventing DH to cost more than electricity in areas with forced connection to district heating. The regulation of district heating is currently being discussed on a national political level and the Government signals a wish to make district heating an entirely municipal task [Det Kongelige Olje- og Energidepartement, 2016]. It is uncertain how this will affect the development of district heating in Norway, but it is a factor that could possibly affect the development.

According to Norsk Fjernvarme [N.D.c] district heating in Norway could have positive effects on the Norwegian energy system. Many of the existing DH companies in Norway are founded next to larger cities as they are utilising energy that would otherwise be lost such as surplus heat from industrial processes or heat produced through waste incineration. The expansion of DH could play a role in phasing out oil burners in buildings. Another point that Norsk Fjernvarme [N.D.c] has for the expansion of DH in Norway is that it would contribute to a more reliable delivery of heat as DH is not based only on one source, unlike the majority of the current heat supply within the country. [Norsk Fjernvarme, N.D.c] Despite the fact the DH could potentially contribute positively to the Norwegian energy system by delivering cheap heat to customers, in 2015, DH accounted for only 3% out of the total Norwegian energy consumption [SSB, N.D.].

Problem statement 3

3.1 Research Question

In the problem analysis in section 2.3 it was found that the Norwegian heating sector is unique in European perspective due to it largely being based on individual electric heating. As Europe moves towards an energy system based on fluctuating renewable energy sources, the need for flexibility in the system is increased, and the Norwegian energy system with its abundant hydro power resources is expected to play a key role in providing this flexibility.

The Norwegian energy system is also facing changes in the coming years, on the road towards reducing GHG-emissions. A need to decrease emissions in the transport and offshore oil and gas sector, has these sectors moving from fossil fuels towards electricity. Unless efficiency measures are implemented in other sectors using electricity, it is expected that this shift will entail an increase in the national electricity demand and a change in demand patterns and consequently a need for increased capacity of renewable energy sources. Basing the entire Norwegian energy system on electricity from hydro power is also expected to make the energy system more sensitive towards fluctuations in the energy content in the hydro power reservoirs.

District heating is in the European energy system often seen as a way to increase reliability and flexibility in the energy system and decreasing GHG-emissions by increasing the total efficiency of the energy system. However, it is unclear what effects an expansion of the district heating sector will have in a highly electrified Norwegian energy system consisting mainly of controllable dammed hydro facilities and a low penetration of district heating. This leads to the following research question.

How will a shift from the current individual electric heating to district heating affect the operation of the Norwegian energy system and how can potential barriers affect such a shift?

1. *How will the use of different production units in the DH system affect the operation of the energy system?*
2. *How will such a shift affect the potential flexibility within the operation of the Norwegian energy system and its interaction with Europe?*

The purpose of the master thesis is to investigate the effect a shift from electric individual heating will have on the operation of the Norwegian energy system. The energy system is in this context concerns the demand and supply sides of the electricity, heating and transport sector in Norway, together with the needed fuels and production units for these.

Investigating the effect of the operation of the energy system will give information on how the energy system units operate together based on the given inputs. It will also provide information on how the units in the system operate together which in return could give information on the flexibility of the system.

An investigation of the potential barriers is needed in order to discuss the realistic possibility of a shift from individual electric heating to district heating. The barriers that are to be investigated are technical, economical and legal barriers for the shifting of individual electric heating to district heating in Norway.

Furthermore, the thesis investigates the effect different production units in the DH system have on the operation of the Norwegian energy system. This will be done by designing and analysing two future DH system scenarios with different production units by using the modelling tool EnergyPLAN. The scenarios aim at investigating both the effect of changing fuels for heating as well as the effect of changing from individual heating systems to collective heating systems.

The last sub-question aims at specifically exploring how will the flexibility of the Norwegian system be affected by such a shift, and subsequently if there will be any effects to the European energy system.

3.1.1 Delimitations

- This master thesis does not investigate what is the ideal design and ideal combinations of a district heating system.
- District heating in this thesis is considered as a 'black box' model, where only network losses are included. Network design, temperatures, substations, etc. are not considered.
- District cooling is not modelled beyond the Reference scenario.
- Heat savings are not implemented in the Energy PLAN model.
- The EnergyPLAN model only takes into account already existing electricity only producing units. Therefore, no additional electricity only producing units are added to the future scenarios.
- The transport sector in the future scenarios remains as it is in the reference scenario designed in EnergyPLAN.
- The shift's effect on the potential to provide flexibility to the European energy system is only analysed through parameters that are defined in this thesis to contain information on this matter. The European energy system is not modelled.

3.2 Report structure

The following figure 3.1 illustrates the structure of this master thesis report.

The darker blue boxes in the middle of the figure illustrate the different chapters in this master thesis, and how these are connected. Two lighter blue boxes, representing sub-questions to the research question, are connected to the chapter including the research question. These are used to help elaborate on the research question. Following, the theoretical framework and methodology chapters are used to set the framework for

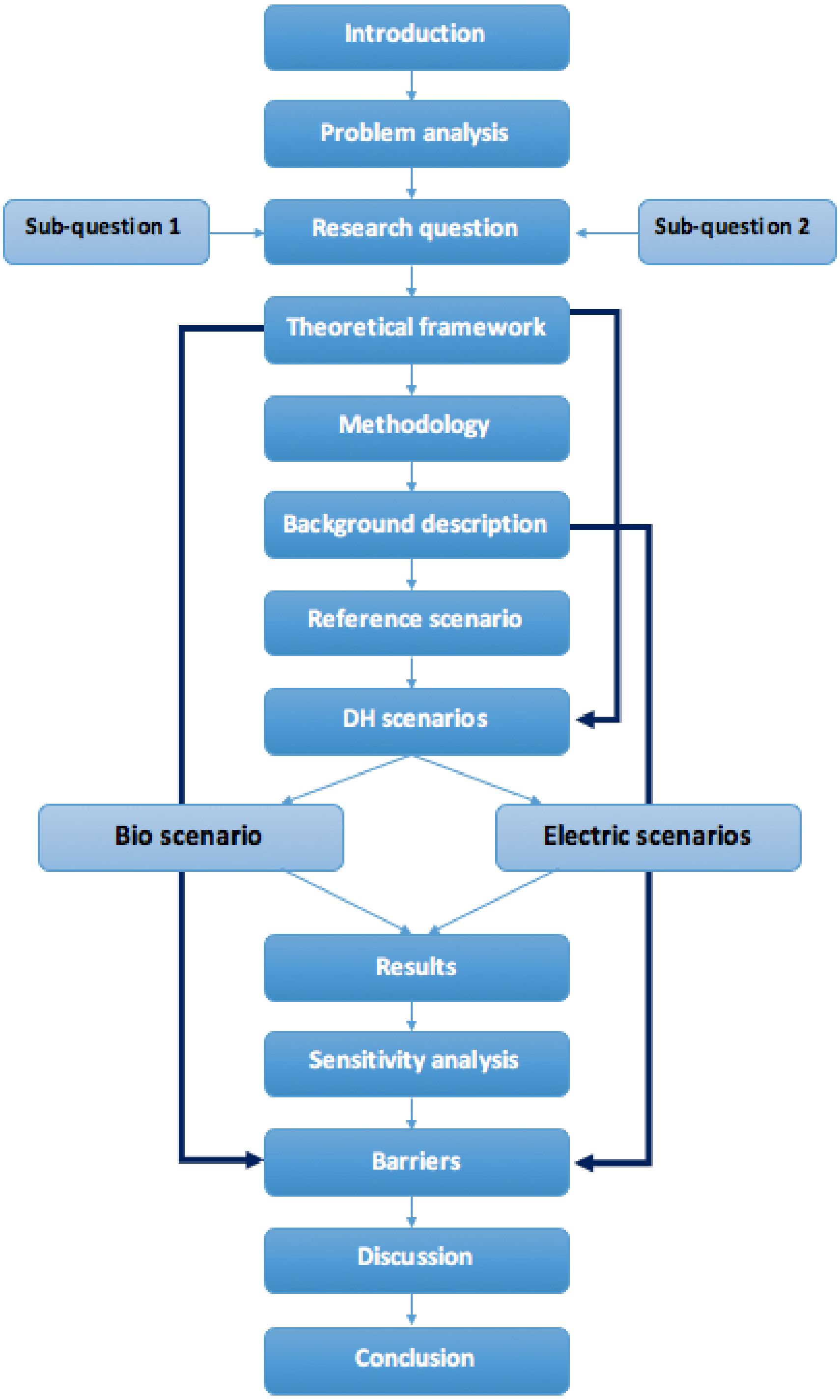


Figure 3.1: Report structure of the master thesis. Own figure.

answering the research question and explain the methods used. The theoretical framework is also used to provide a basis for constructing the DH scenarios and also to help identify different barriers to a shift to DH. The background description chapter provides background information that serves as basis for the Reference scenario and the identification of barriers. The Reference scenario is constructed as a basis for comparison when shifting from individual electric heating to DH. In the DH scenarios chapter four scenarios representing different shifts of individual heat demand are constructed using biomass boiler and HP's as main production technologies. Then, the results from these are presented, followed by a sensitivity analysis. After that, barriers that could potentially hinder the shift from individual electric heating to DH are identified, followed by a discussion chapter, where different aspects from the master thesis are considered. Based on the findings in the previous chapters a conclusion answering the research questions is made.

Theoretical framework 4

The purpose of the following chapter is to define and present the theoretical framework that is used for modelling and anlysing the effects of shifting from individual electric heating to DH in Norway. Firstly, the concept of heating and DH is presented, which forms basis for the modelling of the Norwegian heating sector and the design of scenarios for DH in Norway. Thereafter, the concept of flexibility in the Energy system is defined in order to understand how the shift to DH can affect the flexibility of the Norwegian energy system. Lastly, the theory of technological change is presented to better understand the changes that a shift from individual electric heating to DH entails.

4.1 Heat demand

This section provides an insight on the definition of heat demand and the types of heat demands as described according to Frederiksen and Werner [2013]. It was deemed an important theoretical knowledge to be included in this chapter as the heat demand for Norway was an area of difficulty, however a very important part of this thesis. The heat demand of Norway, as described in section 6.2, is following the logic of the following section.

A heat demand is a demand for heating with two components: a heat energy demand and a heat power demand [Frederiksen and Werner, 2013]. The heat energy demand describes the energy needed for heating over a specific time [kWh] whereas power describes the rate at which the heat is needed [kW]. The heat power demand therefore describes the peak capacity needed to fulfil a heat demand.

Frederiksen and Werner [2013] split heat demands into the following categories:

- Space heating
- Domestic hot water demand
- Industrial demands
- Other heat demands

[Frederiksen and Werner, 2013,pp. 43-63]

The space heating demand originates from the need to create a comfortable indoor temperature [Frederiksen and Werner, 2013,p.43]. The demand for space heating is dependent on the heat losses and gains from and in the building. The heat losses from a building is highly dependent on the outside temperature and buildings in colder climates will, with the same building standards and indoor heat gains, have a higher heat demand than buildings in warmer climates.

Domestic hot water demand is the demand for heated water used in for example taps and showers. This demand is not temperature dependent, but to a larger extent dependent on personal consumption patterns. There are however some general tendencies that can be observed in the hot water demand. According to Frederiksen and Werner [2013] there is a relation between the degree of occupancy and the hot water demand: in winter the degree of occupancy and consequently the hot water demand is higher than in summer when the occupancy is lower. Furthermore, the hot water demand is low during the night and higher in mornings and evenings [Frederiksen and Werner, 2013,p.54].

Industrial heat demands need to be separated from heat demands in buildings in the residential and service sector due to its characteristics. Specifically, industrial heat demands have wide variations in temperature levels, ranging from under 100° to over 400°. The reason for the wide range of temperature in industrial heat demands is the diversity of the processes in which the heat is used. Low temperatures under 100° are typically used for space heating, hot water demands, washing, rinsing and food preparation. Higher temperatures are needed for processes such as evaporation, drying, manufacturing of metals, glass and etc. [Frederiksen and Werner, 2013,pp.60-61]

Other heat demands are described shortly in Frederiksen and Werner [2013] and include:

- Ground heating
- Agricultural heating
- Cold generation
- Process heating
- Domestic services

[Frederiksen and Werner, 2013,pp.62-63] These are not explained in detail in this master thesis, but it is known that they are present.

4.2 District heating

In order to be able to model DH scenarios in this master thesis, an understanding of what is the idea behind DH is needed. This section is used as a basis for the chapter 8 where the design for the future DH scenarios is outlined.

The concept behind district heating systems is to deliver heat efficiently to the end-users for space heating, hot water for domestic needs and industrial processes. The heat is moved through pipeline networks containing pressurised water acting as the heat carrier. Different fuels could be utilised in the DH system - fossil fuels, renewable energy sources such as biomass, solar and geothermal heat, excess heat, etc. According to Frederiksen and Werner [2013] the energy supply to the DH system should be heat obtained from solar thermal fields, geothermal energy and local biomass as well as excess heat from CHP's, waste incineration plants and industry and in general renewable energy sources and heat sources that would otherwise be wasted. Utilisation of large heat pumps and electric boilers would be another way to supply the DH system but only if the carbon content of the electricity used is very low, as is the case in Norway (98% of the electricity coming from RES, see section 2.3). These technologies could also be used to balance the electricity system. Fossil fuels are used for peak loads and as a backup. According to Frederiksen and Werner [2013] in order to have a competitive DH system the heat sources used need to be obtained locally and cheaply, the pipeline networks should not be long, thus reducing investment costs and sufficient heat demands must be present i.e. hot water, space heating, etc. [Frederiksen and Werner, 2013]

According to [Frederiksen and Werner, 2013] there are currently five suitable local fuel and heat sources that can be used for district heating:

- Combined heat and power plants (CHP)
- Waste-to-energy (Waste incineration plants)
- Excess heat from industrial processes
- Combustible renewables
- Geothermal heat

This list does not include for example solar district heating, which is also used in many district heating systems around the world. Furthermore, electricity used directly for heating in for example electric boilers is not included. These are however sources that are already present in the Norwegian district heating system, as described in section 2.3.2.

Frederiksen and Werner [2013] distinguishes between the energy inputs into the district heating system, and groups them into two main groups: primary energy supply and secondary energy supply. The distinction between these two lies in the previous use of the secondary energy supply - this is resulting surplus energy from processes that use primary energy supply, such as for example electricity generation. Figure 4.1 shows how Frederiksen and Werner [2013] illustrate how primary and secondary energy supply should be utilised in district heating.

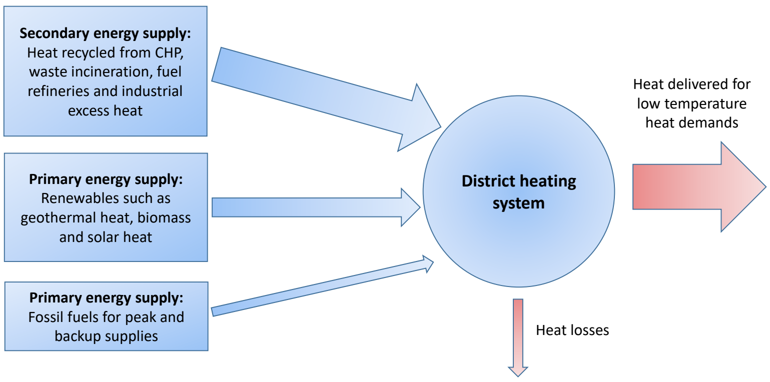


Figure 4.1: The fundamental idea of a district heating system. Figure recreated from Frederiksen and Werner [2013,p.22].

The arrows in figure 4.1 are weighted according to how the supply for district heating should be distributed - secondary energy supply should make up the largest part of the production. Fossil fuels should only be used for peak and back up supplies.

Electric boilers are not included in the figure by Frederiksen and Werner [2013], just like it is not mentioned in the list of suitable local fuel resources for district heating earlier in this section. However, if including electric boilers these would most likely be classified as primary energy supply as electricity is not a surplus energy source. Furthermore, it could be discussed whether electricity should only be used for peak and back up load.

4.3 Flexibility

In order to understand the effect a shift from individual electric heating to district heating will have on the flexibility of the Norwegian energy system, it is needed to define and understand what is meant by 'flexibility'. The purpose of the following section is therefore to analyse what flexibility in an energy system is and how it is used in this master thesis.

Flexibility describes an energy systems' ability to respond to change in demand and supply. Traditional energy producing units provide flexibility in the possibility to regulate the fuel input and the production of energy. Renewable sources such as wind and solar do not provide the same flexibility in production as the input can not be regulated in the same manner as traditional power plants based on combustion technology.When the prevalence of RES is expanded the flexibility of the energy system consequently changes. If there is not enough flexibility in the system, it may be needed to curtail production from wind and solar, which can have negative economical consequences on owners of these units, by reducing the production revenues. [Cochran et al., 2014]

In a paper by Cochran et al. [2014] the following characteristics needed for a flexible power system are identified:

- Flexible generation
- Flexible transmission
- Flexible demand-side resources
- Flexible systems operations

Flexible generation include power plants that are able to regulate up and down quickly and that can operate also at low energy output levels. Having *flexible transmission* is described as having transmission networks with limited bottlenecks and access to networks with a broad range of balancing resources, including power exchange between neighbouring countries. Included in *flexible demand-side resources* is storage and demand responds through smart grids, market signals and load control. The characteristic of *flexible system operations* refer to operation of existing energy systems, such as forecasting for renewable energy production, more frequent decision making closer to real time and better collaboration between operators. However, flexible system operation is dependent on having sufficient physical flexibility in the energy system. [Cochran et al., 2014]

The need for flexibility in the energy system is also described in IEA/Nordic Council of Ministers [2016] which operates with the following options for adding flexibility to an energy system:

- Flexible supply
- Flexibility by linking the electricity sector and district heating
- Storage
- Flexible demand

Where *flexible supply* includes flexible production units such as hydropower with reservoirs and thermal power plants. *Flexibility by linking the electricity sector and district heating* is related to the use of co-generation plants which can switch between producing only electricity and electricity and district heating. Furthermore, this could add to the flexibility of the system by introducing electricity consuming heat production unit that can be run on excess electricity in the system. *Storage* units can increase the flexibility of the system by allowing to store energy when there is a surplus and utilise it at times where energy is needed. Storages for both heat, electricity and fuels can contribute to adding flexibility to the system. *Flexible demand* refers to demand response needed for providing back-up power when renewables are not producing, increasing the value of renewables in hours with high production and balancing fluctuating renewable electricity closer to real time. Introducing price signals can help increase flexibility by giving customers an economical incentive to shifting electric load from hours with lack of electricity to hours with surplus electricity, shaving peaks by reducing demand in peak hours where there is a lack of electricity and shifting fuels to electricity in periods with surplus production. [IEA/Nordic Council of Ministers, 2016]

Both Cochran et al. [2014] and IEA/Nordic Council of Ministers [2016] point to the need for having flexible energy sources to increase the flexibility in an energy system, such as controllable hydro power. Even though there are differences in what is defined as measures to increase flexibility in an energy system, the overall idea is the same: flexibility in a system is dependent on the ability to regulate the energy system according to production and demand, using flexible production units, energy exchange, energy storage and demand response in the system. An integration of different energy sectors, specifically relevant for this master thesis - the electricity and heating sector, can increase the flexibility by increasing the possibility for both flexible production and flexible consumption.

What concerns *flexible transmission*, one could argue that this is also dependent on the flexibility in the energy system on the other side of the transmission line. The idea of Norway providing flexibility to the European energy system is based on the fact that the Norwegian energy system has flexible generation units in their abundant hydro resources that provides flexibility within the country. However, the flexibility within the Norwegian energy system is also dependent on the capacity of the flexible units. Norway's ability to provide flexible transmission depends therefore, not only on the transmission capacity, but also the ability to utilise excess electricity production imported from Europe and the possibility to increase Norwegian production when electricity is needed to be exported to Europe.

The following sections seek to elaborate on the export and import between Norway and Europe, in order to understand how capacity and flexibility within the country affects the flexible transmission to Europe, and how to quantify this flexible transmission potential.

4.3.1 Export capacity

The export capacity between Norway and Europe is, as previously explained, first and foremost limited by the capacity of the interconnections to Europe. However, looking beyond the capacity of interconnections, the export capacity of Norway also depend on the energy balance within the country and on the available capacity for production of electricity. Assuming that Norwegian electricity production first and foremost is supposed to cover the Norwegian electricity demand, in order to be able to export electricity, excess production capacity is needed. Figure 4.2 shows the relation between the potential hydro power production and electricity demand in 2015 in Norway.

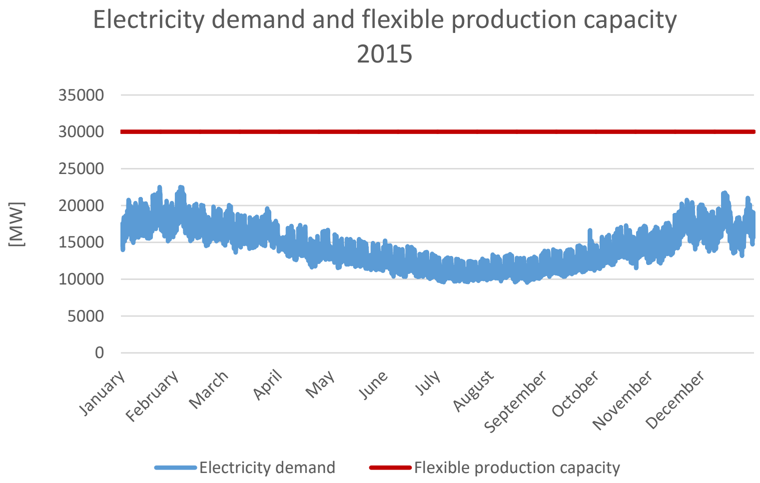


Figure 4.2: Relation between installed hydro power capacity and electricity demand. Own figure based on data from [Nordpool, N.D.].

In figure 4.2 it can be seen that the electricity demand at no point exceeds the potential hydro power production capacity in 2015.

The export capacity of Norway is therefore dependent on the available capacity for production on dammed hydro power plants, exceeding the export capacity in the specific hour. Hydro power is not an unlimited source of energy, and is dependent on the energy content available in the hydro reservoirs. The energy content in the reservoirs is therefore an additional limit to the export capacity. However, excess production capacity available, does not necessarily entail that the export capacity will be utilised. It must be assumed, that increasing the production for export purposes will only be done when it is economically viable.

4.3.2 Import capacity

As for the export capacity, the capacity of interconnections will also serve as a physical limit for the import capacity. The import capacity of Norway is more difficult to set a physical number on, as this depends on several factors.

Consumption of electricity is highly dependent on consumption patterns, whether they are individual, from industry, service sector etc. The production is dependent of electricity within the country which is dependent on the different technologies used for production, the electricity market situation and the demand in the country.

As described in section 2.2 Norway functions as a 'virtual green battery' today by importing electricity instead of producing when there is an excess electricity production in Europe. Dammed hydro power is highly controllable, and are required to be able to change from nominal production to zero within 30 seconds [Statnett, 2012]. As long as the total electricity consumption minus other fluctuating renewable production exceeds the interconnection capacity it is assumed that there is an import capacity in Norway.

If an expansion of the district heating sector in Norway should help contribute to the import capacity in the country it would be through the addition of flexible units running on electricity that could utilise imported electricity instead of reducing the production of the hydro power plants. However, a conversion of electrical energy to thermal energy would entail a shift from a high grade form of energy to a lower grade of energy. As the electricity would be stored as heat instead of electricity it would also conflict with the green battery idea, as the heat cannot directly be converted back to electricity. However, at there may be some hours where it is economically more feasible to convert imported electricity into heat instead of turning down the electricity production from dammed hydro power. A production of heat that is stored to be used later could potentially free up electricity production capacity for hours where it is needed elsewhere than for heat production, and could in that way function as a 'virtual green battery'. An implementation of heat storages in the district heating system could therefore potentially increase the flexibility of the energy system.

4.3.3 Quantifying flexibility

Through the previous sections it was analysed how import and export capacity, as means to quantify the flexibility the Norwegian energy system can provide for Europe. While it is possible to set a physical limit on both depending on the capacity of interconnections, and on the available production capacity, the possibility of providing flexibility to the European energy system is not simply a matter of physical capacity. As briefly mentioned in section 4.3.1 it is also assumed, that the question of flexibility also is one of economical matter. This can again be related to the *demand response* which was presented as a measure to increase flexibility of an energy system in both Cochran et al. [2014] and IEA/Nordic Council of Ministers [2016] and relying on price signals to increase the flexibility of a system. According to IEA/Nordic Council of Ministers [2016] these price signals are already present in the system, where in periods with large production of electricity from renewable sources, the prices are low, while when the production is low, the prices are higher. This is a natural consequence of the electricity market pricing being based on the principle of supply and demand, where a high demand and a low supply would lead to high electricity prices, while a low demand and a high supply would lead to lower electricity prices [Nordpool, N.D.]. A model of the operation of the Norwegian energy system using a market economic optimisation, could therefore be expected to give information regarding the flexibility of the system when investigating the import and export of electricity. An increase in the number of hours with import and export could indicate a better demand response to the European energy system and thereby describe an increase in flexibility to the European energy system.

What concerns flexibility within the Norwegian energy system, it is according to IEA/Nordic Council of Ministers [2016] assumed that a better integration between the Norwegian electricity and heating sector, which is also the basis for analysing what is the effect that a shift from individual electric heating to district heating. It is assumed that district heating would increase the flexibility of the system by spreading the production to different sources and providing increased potential for demand response through adding the potential of heat storage on a central level. The flexibility within the Norwegian energy system can also be related to the import and export to Europe. In a technical optimisation, focusing on fulfilling the energy demands within the country, the amount of import and export will depend on the physical capacity of the energy system, and thereby be related to the flexibility of the system. In a technical optimisation, a decrease in import and export is expected to indicate an increase in the flexibility within the Norwegian energy system.

Based on the previous analysis of flexibility, the following parameters are identified to give information about the flexibility of the system:

- Technical optimisation
  - Hours with available flexible production capacity larger or the same as the interconnection capacity
  - Difference between electricity consumption and production capacity in a certain hour
  - Number of hours and total amount of electricity import and export
- Market economic optimisation
  - Number of hours and total amount of electricity import and export

These parameters will be analysed and compared in the simulation of a Reference scenario based on the current Norwegian energy system, and scenarios where a shift from individual electric heating to district heating is made, using the simulation tool EnergyPLAN.

4.4 Theory of technological change

A shift from individual electric heating to district heating will entail a technological change. The following sections aim to describe the theory of technological change and how it is interpreted in this master thesis.

In order to understand the theories of technological change and how a shift from individual electric heating to DH is a technological change, a definition of 'technology' is needed.

According to Misa [1992] technology is often defined as knowledge. It is pointed out that, according to Mokyr and Parayil, knowledge is part of the technology, and other authors believe that knowledge is a way of describing technology. The definition of the word has however evolved with time, some authors suggest that a clear definition is not necessary and thus it would be left to be interpret more freely. However Misa [1992] also argues that such ambiguous definition may be too confusing. Furthermore, Hughes characterised technology with four elements: "... materials, technique, power, and tools ...". The final interpretation in Misa [1992] was that technology is closely related to the living world. Gökalp develops this idea and adds the connection of political institutions to technology. [Misa, 1992] Another definition of technology is made by Müller, Remmen and Christensen who point out "Technique, Knowledge, Organisation and Products" as key elements, where organisation could be seen as different governmental institutions taken together with all supporting legislations [Lund, 2014b]. Later Hvelplund [2013] adds profit as the fifth key element of technology, which according to Lund [2014b] is a valuable element when analysing changes made in energy systems. The following figure 4.3 illustrates the definition of technology according to Hvelplund [2016].

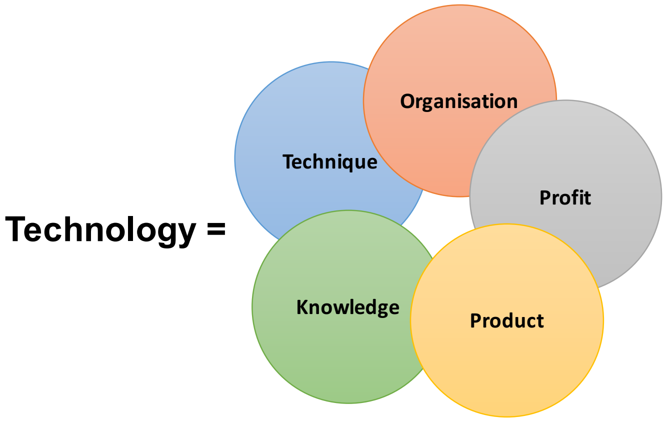


Figure 4.3: Definition of technology. Based on Hvelplund [2016].

When one of these five elements are changed, then a technological change has occurred. When two or more elements are changed, this is considered to be an indication of a radical technological change. [Hvelplund, 2013] Hvelplund [2016] also explains that when one is dealing with a technological change it is important to analyse what is the change that needs to be done and to identify which elements within the technology that should be changed, how they are changed and evaluating the difficulties of these changes and to whom. Additionaly, it should be evaluated if the change is a technological change or a radical technological change. And if it is a radical technological change - how difficult is it? He identifies that a difficult radical technology change occurs when there are difficulties concerning:

- " Need of new technology;
- Need of new organisations;
- Need of new knowledge;
- New and so far weak actors that should earn profit;
- Old and politically strong actors should lose profit". [Hvelplund, 2016]

Relating the theory of technological change and radical technological change to the research question in this master thesis, it needs to be analysed how the shift from individual electric heating to DH represents a technological change. The district heating sector only represents a small share of the heating sector in Norway today, and it could be considered that the sector is still under development. A change from a heating sector based largely on individual electric heating to a heating sector based on DH is assumed to entail a change in several of the elements of technology defined in the previous. The changes in *organisation* can be identified in the legislative system of Norway, where new laws and support schemes are needed to frame the legislative framework concerning DH, as well as incorporating DH into existing framework. DH is not an entirely new area in the Norwegian energy sector, but has recently been subject to changes in the organisational elements, both related to the legal framework and also related to the organisational bodies. This is described further in section 6.4. Furthermore, a shift from individual electric heating to DH would entail a change in the *profit* element of technology, as new actors may be introduced in the energy market, and the profit element could change from the traditional electricity market players to new DH actors. Whether or not there is a change in the product when shifting from individual electric heating to DH depends upon what is considered as the *product*. If the product is considered to be what is delivered in the distribution network, it could be argued that there is a change in product. However, if the *product* is considered to be heat, it could be argued that there is not a change in the product, but simply a change in the *technique* in how heat is produced and delivered. It could also be argued that there is a change in the *knowledge* element of technology as well, as there is a need for new knowledge for customers on how to distribute heat in buildings, knowledge of new markets for suppliers and knowledge of how to deliver DH efficiently in Norway.

In this master thesis, it is chosen to focus upon the change in the *organistation* and *technique* elements of technology when investigating the shift from individual electric heating to DH. It is chosen not to investigate the *profit* and *knowledge* elements as these are outside the scope of the thesis. Furthermore, it is chosen not to include the *product* element, as the product in this master thesis is considered to be heat. This is illustrated in figure 4.4.

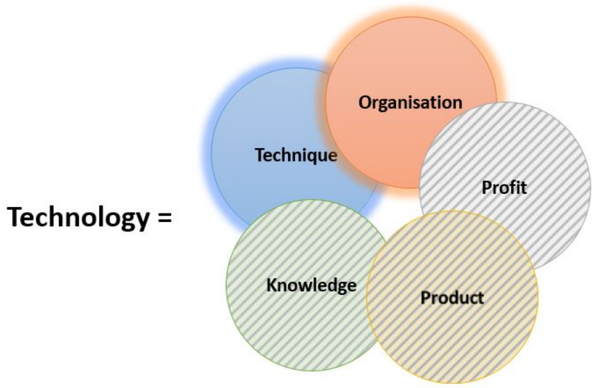


Figure 4.4: Technological change elements considered in this master thesis. Based on Hvelplund [2016].

In figure 4.4 the highlighted elements are used further in the investigation while the striped elements are disregarded. This provides basis for an investigation of what potential barriers can be related to the change in these elements of technology.

Methodology 5

The purpose of the following chapter is to present and analyse the methods used in this master thesis. The methodology starts with introducing the overall research method, moving on to the data collection methods and the modelling tool used for the simulation of the operation of the Norwegian energy system.

5.1 Research method

The overall research method used in this master thesis is a mixed research method. This method is characterised by mixing both qualitative and quantitative research methods. In general, a quantitative research method can be described as a method seeking to quantify a problem or information, while the qualitative research method is one of explanatory character. Quantitative methods are often number based and focus on the objective descriptions while qualitative methods to a larger extent focus on subjective descriptions [Oak Ridge Institute for Science and Education, N.D.].

In this master thesis, quantitative research methods are used to quantify the problem, for example when modelling and simulating the operation of the Norwegian energy system using the simulation tool EnergyPLAN. Data collection of numeric inputs for the modelling of the Norwegian energy system through the review of documents and use of e-mail correspondence can also be classified as quantitative methods.

Qualitative methods were used to broaden the understanding of the Norwegian energy system and the quantitative research and also for general descriptions and analysis of for example the barriers. The main quantitative methods used in this master thesis are literature review and communication through email correspondence.

By using a mixed research method, the two research methods are complementing each other. Consequently, the limitations that the two methods have when used alone are minimised and the two methods together contribute to a more thorough research. However, this type of research is associated with more time consuming research processes, than if only either qualitative or quantitative research methods are used. [Ivankova et al., 2006]

The mixed research method is also related to triangulation technique. The triangulation is characterised with the use of more than two methods, theories, data sources or researchers. The triangulation is also divided in within-method and between-method triangulation. The within-method triangulation uses either numerous quantitative or numerous qualitative methods, while the between-method triangulation uses both qualitative and quantitative methods. [Johnson et al., 2007]

In this master thesis, the between-method triangulation is used, where multiple data collections are gathered. These methods are described in the following sections.

5.2 Data collection

Data can be separated into primary and secondary data as well as quantitative and qualitative data.

The primary data are characterised with gathering of new information that has been collected through experiments, interviews, surveys, etc. Secondary data are used in this research. These are types of data that have been already previously gathered, processed and analysed from somebody else. When using secondary data, the researcher is unaware of how these data have been collected and analysed, so it is important that data are taken from various sources. Before using such data, these data need to be examined and according to Kothari [2004] there are three characteristics that the data have to posses in order be to considered to be used in a research:

- **Reliability** - an investigation of how reliable the data are is done, evaluating data sources and prioritising them.
- **Suitability** - the data used need to be suitable for the specific research, as some data that might be suitable for one research might not necessarily be suitable for another research.
- **Adequacy** - here the accuracy of the data is examined in the specific research, as some data might be more accurate i.e. in a different scope of a research, and some might not. [Kothari, 2004]

The data collection method illustrated in 5.1 is used for the purpose of this research research.

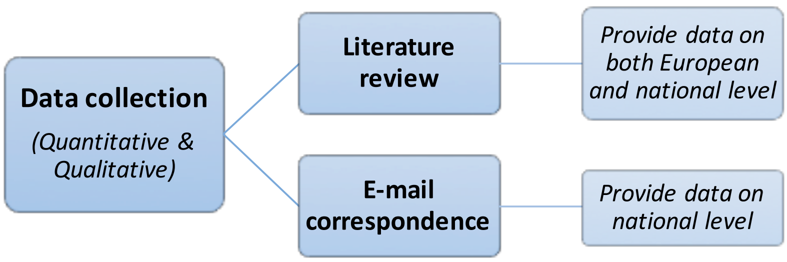


Figure 5.1: Data collection method chosen for the purpose of this research. Own figure.

As seen from the figure, the data collection from both literature review and e-mail correspondence is based on both quantitative and qualitative data. Further down the two methods, literature review and e-mail correspondence, are explained and the choice of sources for these methods are presented.

5.2.1 Literature review

The literature review is a method that provides an understanding of a topic. This could be either previously done research on the topic, different solutions on a problem or simply to gather more knowledge in regards to a research. [Hart, 1998] Cronin et al. [2007] divide the literature review in traditional and systematic literature review.

The traditional literature review, also called narrative literature review, is used to provide broad background information in order for the reader to gather a more generic knowledge on a topic. Researchers use this type of literature review to also define a problem or to narrow down information that would lead to a research question. [Cronin et al., 2007]

The systematic literature review is characterised by using more precise approach of refining information. It has strict rules of how the review should be conducted, an exclusion and inclusion criteria are defined, literature used is limited to the selected search criteria and is used to examine already narrowed down research question. The main purpose of this type of literature review is to exhaust the information on a certain topic completely. [Cronin et al., 2007]

For the purpose of this research a traditional literature review is done. No specific inclusion or exclusion criteria were used. The literature review encompasses of documents which provide background information on the research, the information gathered narrows down the problem and lead to a research question.

Additionally, the sources chosen for the literature review in this master thesis are divided in quantitative and qualitative data which are subdivided into primary and secondary sources. The primary sources include data from official research journals, peer-reviewed journals and national statistical databases. The primary sources category is prioritised over the secondary sources. The secondary sources include international statistical databases, articles and media that do not necessarily have a scientific based information.

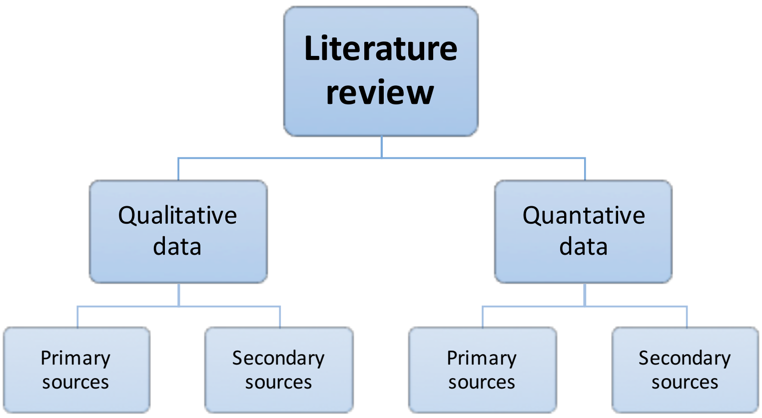


Figure 5.2: Classification of sources in the literature review. Own figure.

5.2.2 E-mail

The e-mail correspondence was chosen for the purpose of this research, as the e-mail method of gathering information is very flexible. It could stretch over weeks or months and could be used whenever needed. Both researchers and respondents have time to think before sending an e-mail to ask or answer questions. The main purpose of using this method in this master thesis was to build upon the data gathered through the literature review and to ensure the validity of some of the data. To certain extent this method subjectivise the collected data and could be biased to the respondents opinions and views.

Main contacts that have been established with the e-mail correspondence are with the following, however the list is not necessarily prioritised:

- Norsk Fjernvarme
- Avfall Norge
- Enova
- Statkraft
- NVE
- SINTEF

These contacts are mainly national organisations that have an overall overview of the topic that has been discussed, rather than a specific knowledge e.g. data on individual DH plants, CHP's, etc.

5.3 Choice of modelling software

The choice of modelling software was done on the basis of a review made from Connolly et al. [2009] on different modelling tools that could integrate renewable energy into various energy systems. In the review almost 40 tools for modelling are analysed. [Connolly et al., 2009] The analysis is done on different characteristics of the tools on which the choice of modelling tool for this research is based.

The criteria for choice of modelling software was based on:

1. Tool that includes analysis of electricity, heat and transport sectors
2. Tool that is able to integrate a 100% renewable energy system
3. Tool that could model a national based energy system
4. Tool that would be able to perform an analysis on hourly bases
5. Tool that is freely accessible

These criteria were chosen as for the purpose of this master thesis the energy system of Norway is needed to be modelled including the electricity, heat and transport sectors. With a modelling tool that is able to include all three sectors, it is possible to investigate the changes made in one or more sectors and subsequently investigate the effects they have on the overall energy system. The investigation in this thesis is based on the interaction between the electric and heating sectors in Norway. Although, the transport sector is not changed in the scenarios modelled for the future, it is still important to be included as the transport sector still affect the energy system of Norway. As the Norwegian energy system is highly based on RES, the possibility of designing a 100% RES system was chosen as criteria. This was an important factor as the desired model for this thesis would have to be able to manage large penetration of RES within the energy system. A national based modelling software was needed as the energy system that was modelled in the thesis is also on a national level. An hourly based model was needed as it is important to be able to investigate hourly changes in the energy system of Norway when changes are implemented. Lastly, the model had to be freely accessible as well as having a relatively large number of users. This was deemed as important as also available information and handbooks of the model provide clarity of how the model works in case of doubt, where a model with small amount of users and almost no or none at all freely accessible documents on the model.

The tools that matched the first two criteria were EnergyPLAN, INFORSE, Mesap PlaNet and LEAP. Out of these, only EnergyPLAN and Mesap PlaNet matched the third and fourth criteria. At the end, EnergyPLAN was chosen as Mesap PlaNet has a commercial availability and has much less users than EnergyPLAN, according to Connolly et al. [2009].

5.3.1 EnergyPLAN

EnergyPLAN is a deterministic input/output model made in Delphi Pascal. The tool is used to model national or regional systems. The whole energy system could be analysed by including electricity, heat and transport sectors. It works on an hourly basis and therefore distribution files used are also based on hourly values thus they have 8 784 data entries according to every hour of a leap year. Distribution files for common years which lack this additional day have the same amount of entries. This is done by repeating the last 24 hours of the year twice. [Lund, 2014a]

The full flowchart interactions in the EnergyPLAN model are presented in figure 5.3.

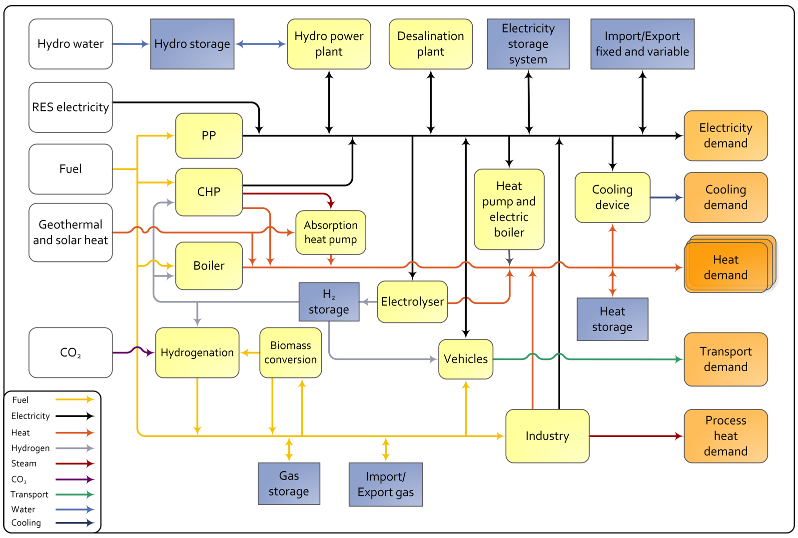


Figure 5.3: EnergyPLAN model flowchart. [Lund, 2014a]

Choice of simulation strategy

The EnergyPLAN tool provides several simulation strategies that can be chosen for the model simulations. There are two main options:

- **Technical Simulation**
  The technical simulation strategy mainly focuses on minimising the use of fossil fuels in the energy system and in the same is trying to fulfil the demands that has been set. In the same time, this simulation accounts for total annual costs of the system.
- **Market Economic Simulation**
  The market economic simulation strategy, on the other hand, focuses firstly on trying to minimise the energy system's operation costs. The energy demand of the system, would then be fulfilled with technologies and fuels that would be the least costly. [Connolly, 2015]

The technical simulation strategy was chosen for the purpose of this research. This strategy has four sub-technical simulation strategies:

1. **Balancing heat demands** - under this simulation alternative the heat producing units are operating according to the heat demand of the energy system, and therefore, units that produce both heat and electricity rely on the heat demand and would not produce electricity if there is no need for heat.
2. **Balancing both heat and electricity demands** - in this strategy the electricity export is being minimised by reducing the use of CHP with either boilers or HP when surplus of renewable electricity is available.
3. **Balancing both heat and electricity demands but reducing the use of CHP when grid stabilisation is needed** - the simulation acts the same way as in the second simulation, with the difference that the use of CHP's is reduced not only when there is excess of electricity in the system but also when the system needs additional grid stabilisation.
4. **Balancing heat demands using tariff** - it operates as in the first strategy with the difference that CHP's do not operate according to the heat demand but rather to the electricity demand. When they produce electricity during peak hours, they are paid three times more or so called "Triple tariff". [Connolly, 2015]

It needs to be taken into account that EnergyPLAN has a prioritisation of technologies used in the DH production. The priority is given first to:

1. Solar thermal
2. Waste incineration CHP
3. Industrial excess heat
4. CHP
5. HP
6. Thermal storage
7. Boilers

In addition to that, EnergyPLAN does not connect the waste incineration CHP's and excess heat from industry with its thermal storage. Therefore, any excess production from these would result in loss of heat.

For the purpose of this master thesis, the technical simulation strategy was chosen with combination of the second sub-technical simulation strategy. Three scenarios are modelled: one Reference scenario, where the heat sector in the energy system is based mainly on individual electric heating and a very small share of district heating and DH scenarios, where an investigation of the shift from individual electric heating to a DH is analysed, using different production units combinations. The main idea of this master thesis is to be able to simulate the Norwegian energy system as realistic as possible and being able to balance both the heat and electricity demands. However, some of the inputs for the Reference and DH scenarios are based on assumptions and therefore it is known that the modelled scenarios might be different from the reality. It is, however, possible to still use the modelled scenarios to view what changes have been made and how they affected the system designed in EnergyPLAN.

Background description 6

The purpose of the following chapter is to provide a background description of all factors affecting the Norwegian heating sector and the expansion of the Norwegian district heating sector. This includes a geographical overview of Norway and the connection to the European energy system, an analysis of the Norwegian heating sector and a description of the current regulations affecting the district heating sector in Norway. The background description would also provide the reader with a summary that is drawn out of the chapter which is then taken into account when designing the reference and future scenarios as well as use when identifying barriers to DH expansion.

6.1 Geography

Norway is a Scandinavian country located in Northern Europe on the west side of the Scandinavian peninsula. It borders Sweden, Finland and Russia by land and the Norwegian, Barents, Skagerrak and North sea by water. The largest city and capital of the country is Oslo [Thuesen et al., 2017]. The location and borders of the country are illustrated in figure 6.1.

Figure 6.1: Map of Norway in Europe. Screenshot from Google Maps [2017] 09.04.17.

Norway's territory comprises of approximately 304 km^2 of land and 20 km^2 of water [Worldatlas, 2015]. The country is narrow with a lot of fjords, high mountains and a long coastline. A large part of the country, mainly in the middle along its length, is formed on a rock consisting of gneiss, granite and others [Bryhni, 2017].

As of 2016, the population of Norway is 5 258 317 inhabitants [SSB, N.D.]. The population density in the country is shown in figure 6.2 from which it can be seen that the areas with the highest population concentration are around the coastline of the country [Thorsnæs, 2016].

Figure 6.2: Population density in Norway in 2016, acquired from [Geonorge, 2017].

The largest share of the population live in the southern areas, stretching from Oslo in the east along the coast to county Møre og Romsdal in the north-west. In 2017 only 10.4% of the population lives in the northern part of Norway, north of county Nord-Trøndelag [Thorsnæs, 2016]. The settlement pattern in Norway has been characterised by spread settlement in rural areas, not settlements clustered around larger farms. The settlement in the northern parts of Norway is located very close to the coast line and often centred around fishing villages, with little to no population in the rural areas in between these. [Thorsnæs, 2016]

The oldest towns were founded on trade, and typically located around ports on the coast. This includes Bergen, Oslo, Trondheim and Stavanger, which are still the largest cities in the country. Towns are often located around train stations. After 1945 the population growth has been concentrated to cities and towns and the urban areas around, while the rural population has decreased. [Thorsnæs, 2016]

There has been an upward trend of an increased share of the population living in urbanised areas in Norway from 2006 to 2016 seen in figure 6.3. In the interval of ten years the number of inhabitants living in cities rose with 17.24%, reaching 4.2 million in 2016 [SSB, 2017].

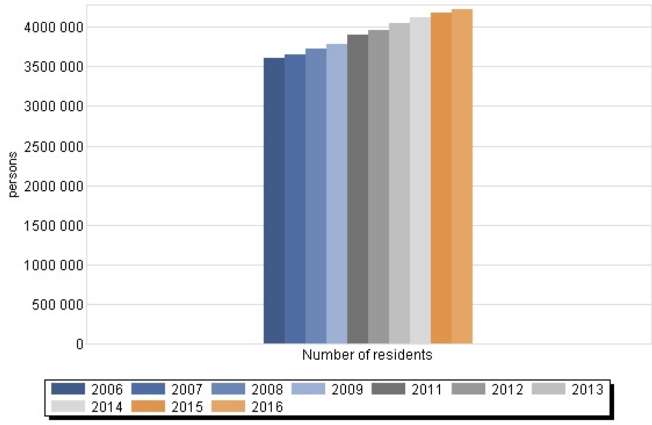


Figure 6.3: Number of residents living in cities [SSB, N.D.]

Norway is the third largest producer of crude oil and natural gas which plays an important role in the economy of the country. Besides its oil production, Norway is the largest hydro power producer in Europe - the country has big natural water reserves that are utilised in producing electricity from hydro power stations which powers the country almost entirely. [Norwegian Environment Agency, 2015]

6.2 Heating sector

In 2.3.2 it was described how the heating sector of Norway is highly based on electricity. In general, it is difficult to know the exact heating demand in Norway and how it is distributed, as data is not measurable and available in the same manner as in countries that have widespread use of district heating and measure their electric heating separately from the rest of the electricity used for electric appliances, lighting, etc. As there are no measured data available, the information regarding the Norwegian heating sector is therefore based on estimations using different methods and different data sources.

The heating demand for the purpose of this master thesis could be roughly split into a space heating demand and a hot water demand, where one would assume that the space heating demand is temperature dependent. However, according to Juhler [2017] the demand for space heating is not strictly temperature dependent, as the Norwegians also heat according to comfortability. For example, it may be assumed that floor heating in bathrooms is mainly used for comfortability. This may be related to the relatively low average electricity prices in the country being 1.36 NOK per kWh, compared to the EU average - 1.87 NOK per kWh as of 2015 [Eurostat, 2017].

According to Norsk Fjernvarme [2016] and Euroheat & Power [2015] an estimation that the total heat market in Norway is approximately 50 TWh was made. However, it is not specified how did Norsk Fjernvarme [2016] and Euroheat & Power [2015] come up with this estimation. For the purpose of this report, this number was used as it was assumed that the organisations which made the estimation are reliable, as Norsk Fjernvarme [2016] is the national DH organisation in Norway and Euroheat & Power [2015] is the international DH organisation in Europe. However, it is known that this estimation of 50 TWh might not be correct and would potentially affect the analyses made in this thesis. Based on a report from Enova [2015] the heat demand in Norway is distributed on the different fuels as shown in figure 6.4.

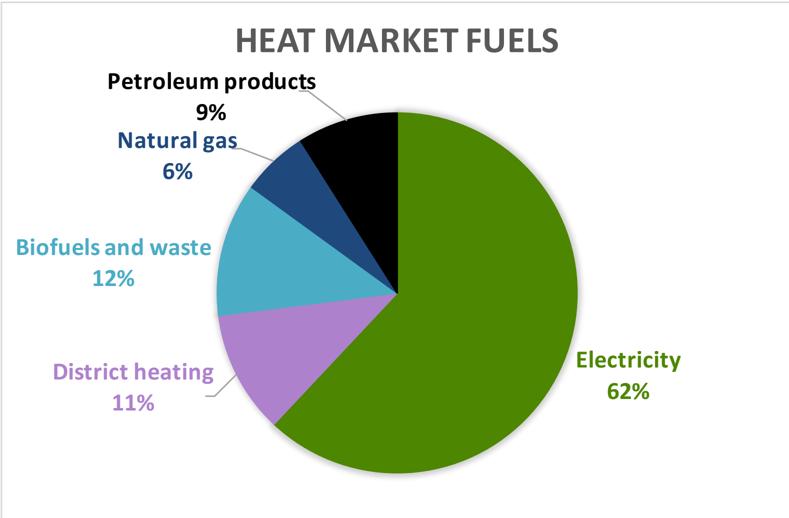


Figure 6.4: Heat market divided by fuels. [Enova, 2015]

The figure is based on fuel shares in the heat market from Enova [2015] which are based on numbers from SSB [N.D.] for 2013. These have been altered to fit the current share of district heating (10%) in the heat market. The original share of district heating in 2013 was 7%, however knowing the current DH share of 11% and the heat market of 50 TWh suggests that the increase of the DH with 4% reduces the share of the other fuels. It was assumed that all four remaining fuels reduced their shares each by 1% as it was not able to determine if one fuel is reduced more than other. This resulted with figure 6.4 seen above.

6.2.1 Heating in the residential sector

According to Enova [2015] more than half the Norwegian heating demand is found in the residential sector, accounting to 39.3 TWh.

For the EU project REMODECE the electricity consumption in 100 Norwegian households was investigated and monitored by SINTEF and Enova to gain information of the electricity use in the Norwegian residential sector. It was found, that in 2006, the year the study was conducted, the electricity use in Norwegian households was distributed as shown in figure 6.5.

From the figure it can be seen that room heating accounts for 64% of the electricity use and hot water for 15%. It is however specified in Feilberg and Grinden [2009a] that these percentages may vary from year to year according to the outside temperature, although 2006 was a reasonably warm year. According to Yr [N.D.] both 2006 and 2015 were 1.8° C warmer than a normal year. Therefore, it is assumed that the distribution of electricity

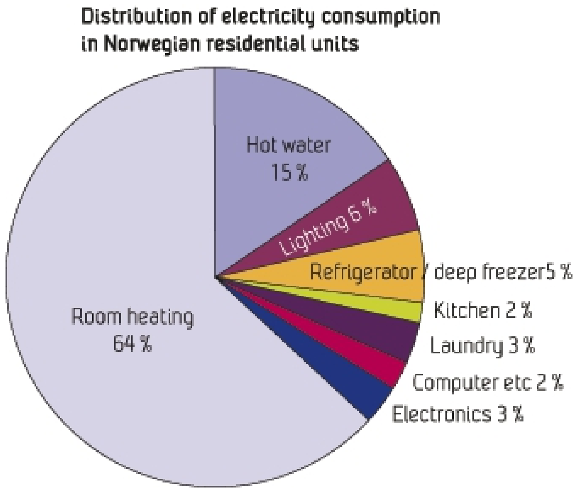


Figure 6.5: Use of electricity for different appliances in Norwegian households in 2006.[Feilberg and Grinden, 2009a]

consumption in households in Norway shown in the figure above would be valid for 2015 as well.

In relation to the REMODECE project, a daily distribution profile for the electricity used for different units can also be found in Feilberg and Grinden [2009b]. This distribution is seen in figure 6.6.

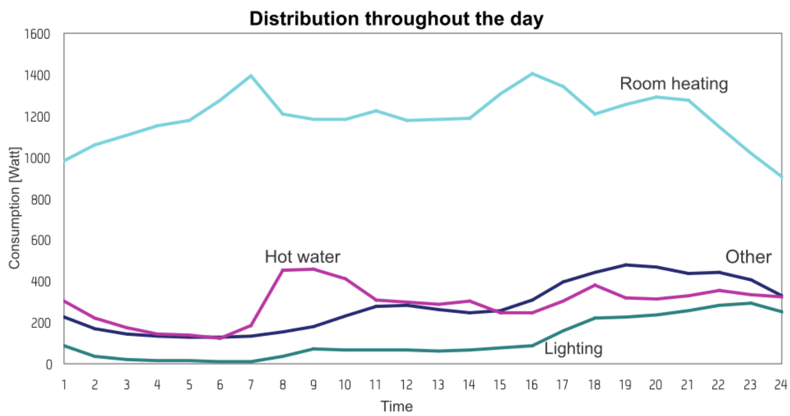


Figure 6.6: Distribution profile for electricity use in Norwegian residential households in 2006. Figure from [Feilberg and Grinden, 2009b].

Here, the cyan line represents the electricity used for heating over 24 hours, and the purple line represents the hot water demand. It can be seen that the hot water demand has a peak around 8-9 in the morning, probably due to showers, and a less apparent peak around 18-19 in the evening. The electricity used for space heating has a peak in the morning around 6-7 in the morning and another peak at 15-16 in the afternoon. [Feilberg and Grinden, 2009b]

The results from the REMODECE project only concern residential households and do not contain any information regarding electric heating used in non-residential buildings, for example within the service sector and industry. For this, it has not been possible to find any specific data regarding the electric heat consumption. Furthermore, the REMODECE project only concerns electricity use in households and does not investigate other heating sources. It has been attempted to contact SINTEF and Enova to find newer or more expansive data for the use of heating and electric heating in all sectors. According to e-mail contact with these, the data from the REMODECE project is the newest data available and there has not been any new research done in this area.

6.2.2 Heat demand in service and industrial sectors

If it is assumed that the remainder of the total heat demand in Norway, excluding the residential sector (39.3 TWh), is used in the service and industry sector, they have a total heat demand of 10.7 TWh. It is not known how this is distributed between the two sectors.

Havskjold et al. [2011] has made calculations for the heat demand in buildings based on the building regulation standards. They estimate a total heat demand of approximately 44.5 TWh in 2008, of which service sector and industry buildings account for 37% and 11% respectively. The total heat demand calculated by Havskjold et al. [2011] is 5.5 TWh lower than the one given in Norsk Fjernvarme [2016] and Euroheat & Power [2015] for the heat market.

It is not known how the heat demand is distributed in the service and industry sectors, as it has not been possible to find a similar distribution profile as the one for residential in figure 6.6.

6.2.3 Cooling demand

According to [Enova, 2015] the total thermal market is 81.7 TWh yearly. If 50 TWh of these make up the heat market. It is uncertain if the difference of 31.7 TWh is assumed to be a cooling demand, if so, this is a very high cooling demand compared to what is found in for example Havskjold et al. [2011], where the cooling demand in 2011 was said to be 1.1 TWh. It is possible that the remaining of the thermal market according to Enova [2015] consists partly of natural cooling, but this is not further described in the report.

As it is not well described what is included in the 81.7 TWh from Enova [2015], it is decided in this master thesis to proceed with an assumed cooling demand of 1.1 TWh as specifically stated in Havskjold et al. [2011]. The cooling demand is mainly from the service and industrial sector, with 65 - 70% estimated to be from buildings in the service sector [Havskjold et al., 2011].

It is known that 169 GWh of the cooling demand is covered by district cooling [SSB, N.D.]. The rest is assumed to be covered by electricity [Havskjold et al., 2011]. It is not known which cooling technologies covers the electric cooling demand. For the purpose of this master thesis it is however assumed a COP of 1, based on the requirements in the building regulations, making the electricity use for cooling identical to the cooling demand [Havskjold et al., 2011].

6.2.4 Potential district heating expansion

Naturally, a district heating system will not be economically feasible if there are no customers connected to the district heating network. This master thesis does not aim to design the network of district heating pipes and customers connected to these. However, in the evaluation of the potential district heating demand it is important to consider the potential customer base, which among other parameters will depend on the building density.

Figure 6.2 on page 36 provides an overview over the population density in Norway. A map of the building density in the country can be seen in figure 6.7.

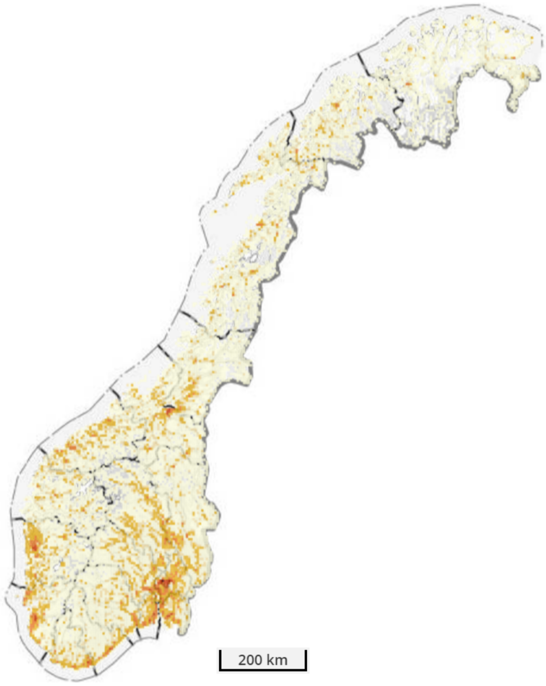


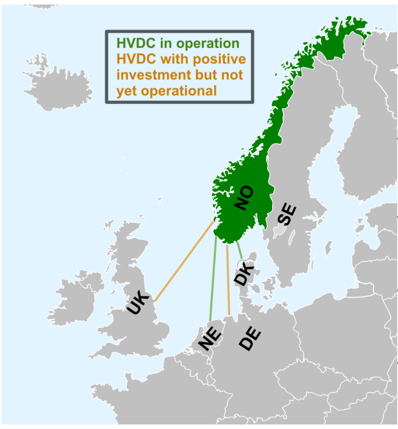
Figure 6.7: Building density in Norway in 2017. Figure from SSB [N.D.].

It can be seen, that the building density map presented above and the population density map presented in figure 6.2 on page 36 seem to be related. A relation between the two does make sense, as a higher population would require more residential buildings as well as more service sector buildings both due to a higher demand for services (hospitals, schools etc.) as well as a higher demand for jobs and consequently office buildings in the area.

Although it is not possible to say how many customers are connected to the different pipelines and is not possible to specify length and consequently cost of pipelines, this is something that needs to be considered in a real system. Therefore, this is something that could be discussed when identifying potential barriers for the future development of DH in Norway.

6.3 Transmission lines

As previously stated in 3, Norway's binding legislative relation to the European union enables the country to be a part of the European internal market and is able to freely trade electricity with the EU member states on the base of liberalised open market. According to NVE [2016c], Norway was a net exporter of electricity - averagely 11.3 TWh yearly, with the exception of 2011 when it was a net importer - 7.6 TWh. More than half of the country's production capacity is flexible. There is a little over 82 TWh of hydro power storage availability. Norway's HVDC connections are illustrated in figure 6.8. The country's HVDC connections are through Skagerrak 1, 2, 3 and 4 to Denmark and through NorNed to the Netherlands. There are also several HVAC connections to Sweden which cannot be seen on the figure below. There are two more HVDC links from Norway that are under construction (orange colour) - to the UK which is planned to be operational in 2021 and one connection to Germany which is planned to be operational in 2020. [NVE, 2016c] The total installed interconnection capacity currently is 6 095 MW, which will increase to 8 895 MW by 2021.



Country	Link name	Capacity	Operation
Norway – Sweden	Various lines along the border	3695 MW	In operation
Norway – Denmark	Skagerrak 1, 2, 3 and 4	1700 MW	In operation
Norway – Netherlands	NorNed	700 MW	In operation
Norway – Germany	NordLink	1400 MW	In operation in 2020
Norway - UK	NSL	1400 MW	In operation in 2021

Figure 6.8: Existing and future connections from Norway to Europe. Own figure based on a map from Wikipedia [N.D.] and data from NVE [2016c]

6.4 District heating policy

This section aims at presenting an overview of the current policies influencing the district heating development in Norway.

6.4.1 Support schemes for district heating

Enova manages the state subsidies of the energy fund whose purpose is to promote a climate friendly restructuring of the energy sector - both consumption and production [Finansdepartementet, 2012]. One way the fund is utilised, is through Enova's support scheme providing financial support for development of district heating and -cooling[Enova, b]. The following measures are some of the measures eligible for support[Enova, b]:

- Establishment of power plants and infrastructure based on renewable energy sources
- Expansion and densification of already existing district heating and -cooling facilities
- Conversion from fossil fuel production to renewable energy production in existing power plants

The support provided from Enova is an economical investment support that can help make investments economically feasible for the investors [Enova, b]. The financial support is supposed to cover the added cost of investing in energy- and environmentally friendly projects. A requirement to receive support from Enova is that the financial support is necessary for the realisation of the project. [Enova, a]

Between April 2016 and April 2017, 19 projects received financial investment support from Enova, with the economical amount received per project ranging from 190 000 to 45 000 000 NOK. In total, the 19 projects have received 180 000 000 NOK in financial support. [Enova, b]

There are currently no national support schemes for home owners related to the connection to DH. Only one municipality, Oslo municipality, has a municipal support scheme that may be used for home owners to connect to DH, where support is provided for the installation of waterborne heating systems based on renewable energy. [Oslo Kommune, N.D.]

6.4.2 Laws and regulations regarding district heating

District heating is regulated through the energy act which applies to the "generation, conversion, transmission and distribution of energy" [Olje- og energidepartementet, 2017]. Chapter 5 in the energy act regulates the licensing for district heating plants, mandatory connections and delivery, prices and shut downs of district heating plants.

According to §5.1 a district heating plant has to have a license to be built and operated. This also applies to plants being rebuilt or expanded. The energy act does not specify clearly which requirements are to be fulfilled in order to be granted a license, but leaves this up to the ministry. It is also up to the ministry to decide for which size of plants the provisions in the energy act is to be applicable for. The ministry referred to is the Ministry of Oil and Energy, and the act is applicable for district heating plants exceeding 10 MW [Det Kongelige Olje- og Energidepartement, 2016]. The specific conditions for licensing are found in the energy regulatory [Olje- og energidepartementet, 2015]. These specific conditions will not be further described in this section, but a suggested change in the national licensing scheme will be further discussed in section 11.1.1.

According to §5.3, if a district heating plant has a heating system that can be connected, the ministry may order the plant to connect with other district heating plants.

Through §5.4 the licensee is required to supply customers with district heating, either themselves or through agreements with other suppliers in accordance with the plan or as agreed upon with the customers. [Olje- og energidepartementet, 2017]

The price of district heating is regulated in §5.5, which states that the price of district heating shall not be higher than the price of electricity within the supply area.

The plan and building act provides rules regarding a building's connection to infrastructure, including connection to district heating networks. The law's §27.5 states that if a building is to be built within a license area for district heating, it may be defined in plans. Plans in this context, refers to plans pursuant to the plan and building act. These are:

- Central government planning regulations (§6.3)
- Regional planning regulations (§8.5)
- Municipal planning regulations (§11.1)

- Zoning plan (§12.1)

In regards to district heating, the municipalities are the ones that are responsible for decisions regarding mandatory connection to district heating [Det Kongelige Olje- og Energidepartement, 2016].

The ministry is through §27.6 allowed to give additional regulations regarding the connection to district heating and the adaptation to use utilisation of district heating.

District heating was before 01.01.16 more closely regulated in the regulation on technical requirements for buildings (TEK10). In § 14.8 it was stated that buildings with mandatory connection to district heating are required to have heating systems adapted for connection to district heating [Direktoratet for Byggkvalitet, 2015]. This requirement is now removed and there are no longer specific requirements in TEK10 for heating systems adapted for connection to DH.

Previously, TEK10 also included minimum requirements for alternatives to electric heating, stating in §14.7 that buildings are to be built so that minimum 40% (60% for buildings over 500 m^2) of the heat demand can be covered by alternative heating sources than direct electricity. This requirement was also removed from 01.01.16.

There are therefore no current regulations in TEK10 specifically concerning the connection and adaptation to district heating, but there is still a requirement in §14.4 concerning flexible heating systems and adaptation to use of low temperature heating for buildings over 1000 m^2, which can favour district heating to some extent.

7 Reference scenario

In order to investigate the effect of a shift from individual electric heating to district heating, a reference scenario is constructed. The following chapter presents the reference scenario constructed for this master thesis.

The base scenario represents the current Norwegian energy system with individual electric heating, with certain modifications for comparability. It has been chosen to construct the Reference scenario using data from year 2015. This year was chosen, as at the time of starting the data collection, this was the most recent year with complete data sets for the production in both the district heating sector and electricity sector. In cases where data from 2015 have not been available, the most recent data available have been used. This concerns, among others, data on capacities and prices. Some capacities are also based on calculations using production estimations on full load hours from NVE [2015].

The modifications from the current energy system are the inclusion of future interconnection capacity that is to be available in 2021 as well as an exclusion of a power plant planned to be decommissioned in 2018. These modifications are made in order to ensure comparability in the evaluation of the effect of shifting from individual electric heating to district heating. It is also chosen not to include costs of interconnections as the interconnection capacity is not changed between the reference scenario and the district heating scenarios.

All inputs used in the reference model, including descriptions of these, can be found described in appendix A.1 to A.4.

It should be pointed out that the biomass in the following can refer to both solid biomass and also a mix of biogas, solid biomass and organic waste, which is not included in the waste incineration plants. The biomass CHP plants are based on wood chips, while the DH boilers use a mix of biofuels. Furthermore, it should be noted that HP's used in DH consist of a combination of heat pumps and electric boilers, due to how EnergyPLAN treats boilers. This is described further in appendix A.2.3.

The energy system was in chapter 3 defined to be the Norwegian electricity, heating and transport sectors. However, as the objective of this master thesis is to investigate the effect a shift from individual electric heating to district heating has on the energy system, only the electricity and heating sectors are changed between the scenarios, while the transport sector is kept as in the Reference scenario. Furthermore, it is not expected that the shift would directly affect the transport sector, and the transport sector is therefore not analysed in the results of the scenarios. A shift from individual electric heating is expected to have an effect on the electricity and heating production of the system, the interaction between the electricity and heating sector and the import and export of the system. The change in these parameters can give information on the flexibility of the system, as defined in section 4.3. When changing the operation of a system, other parameters such as cost and emissions are also affected. These parameters are important to assess the economical costs of a system and how the system fulfils the requirements from the EU to increase the renewable share and reduce the emissions.

The results of the simulation of the Reference system is therefore to be investigated for the following:

- Electricity production
- Individual heating production
- District heating production
- Thermal storage content
- Hourly electricity demand and hydro power capacity
- Import of electricity
- Export of electricity
- Total annual costs
- Emissions
- Renewable share

The operation of the Reference scenario is simulated using a technical simulation balancing both heat and electricity demands in the simulation tool EnergyPLAN. EnergyPLAN and the choice of simulation strategy is further described in section 5.3.1.

7.1 Results from the Reference scenario

In the following section the results from the technical simulation of the Reference scenario are presented and analysed.

Figure 7.1 presents the electricity production in Norway in the Reference scenario.

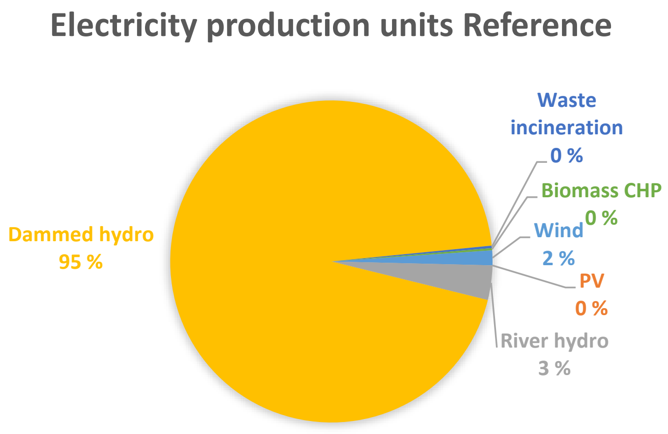
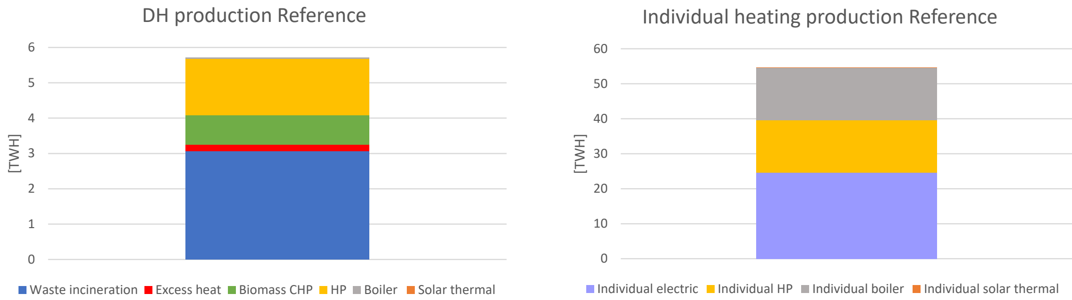


Figure 7.1: Electricity production divided on production units in the Reference scenario. Own figure.

As it is seen in the figure, the dammed hydro power has the largest share of the electricity production with 95%, followed by the river hydro with 3% and the wind power with 2%.

The PV, biomass CHP and waste incineration plants shares appear to be 0% as their shares represent too small electricity production compared to the other production units. If compared to figure 2.1 on page 6, the total share of hydro power production is simulated to be 2% higher in the Reference scenario. It needs to be taken into account that the natural gas CHP is not included in the model of the Reference scenario, and the additional hydro power production may be used to cover this. Furthermore, it may look like the production from waste incineration and the biomass CHP accounts for 0% of the production in the Reference scenario, but this is due to the decimals not being included. However, the actual combined share of these units is 0.4%. If assuming the natural gas production in figure 2.1 is replaced with hydro power, the simulation of the Reference scenario give similar results to the production data from 2015.

Figure 7.2 shows the district heating and the individual heating production in the Reference scenario.



(a) District heating divided on different production units.

(b) Individual heating divided on production different units.

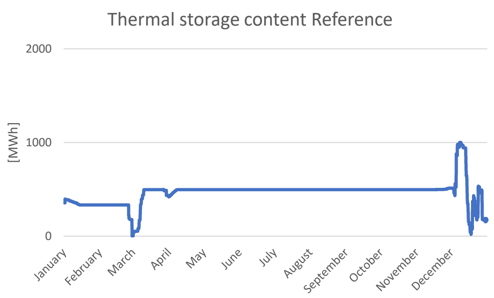
Figure 7.2: Heating production in Reference scenario. Own figure.

The waste incineration plant produces the most heat in the district heating system in the Reference scenario. It is assumed, for the purpose of this master thesis, that it operates on a constant basis throughout the year. However, it might be that in reality it may be possible that the waste incineration ramps its production up and down depending on the amounts of waste or the amount of heat needed in the system. According to statistics from SSB [N.D.] some of the heat produced by waste incineration plants is cooled to air, which could indicate that it is not operated according to heat demands. It should be noted that HP represents a combination of electric boilers and heat pumps with a combined COP of 1.34, which is described in appendix A.2.3. Following in the production of DH are the biomass CHP, excess heat and boilers, which include fossil based and biomass based boilers, and would be referred to just as "boilers" from now on. The solar thermal production is so small that is not possible to be seen on the graph 7.2a. It accounts for 0.004 TWh yearly.

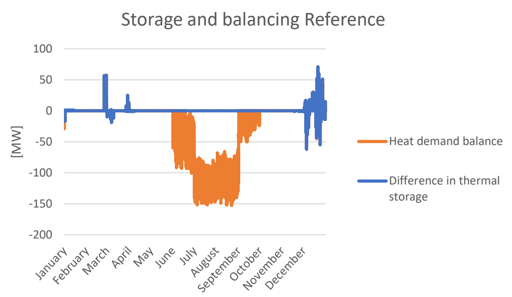
It is difficult to directly compare the results from figure 7.2 to figure 2.7 as this figure is based on the fuel mix for DH production while the results from the Reference scenario are based on the different production technologies. However, according to data from SSB [N.D.] the DH production from waste incineration was 49% in 2015, while in the Reference scenario it is 54%. Furthermore, the heat pumps and electric boilers were used to cover 22% of the DH-demand in 2015, while in the Reference scenario they cover 28% of the demand. The production on boilers is therefore also different from the real life operation shown in figure 2.7. The differences in production between the technical simulation of the Reference scenario and real life may be due to the DH systems being operated on local level and not on national level in real life. Furthermore, differences may occur due to inaccuracies in calculated capacities input in the model of the Reference scenario.

The individual heating production is mainly based on electricity, where electric heaters represent the largest share, followed by electric driven HP. The individual boilers represent another large share of the heating production, as these may be used in the production of heat used for central heating or in individual furnaces. As in the DH production, the boilers illustrated are both biomass and fossil based, but are referred as boilers from now on. Solar thermal heating has again a very small share and is not visible in the graph 7.2b. It accounts for 0.01 TWh yearly.

The thermal storage content of the DH system in the Reference scenario is illustrated in figure 7.3a, while in figure 7.3b, on the right, the difference in the thermal storage content and the heat demand balance are presented.



(a) Thermal storage content in Reference scenario.



(b) Heat demand balance and difference in thermal storage content.

Figure 7.3: Thermal storage operation in Reference scenario. Own figure.

The thermal storage is used in throughout the year, with the exception of the period between May and November. This is explained with figure 7.3 on the right.

As seen from the figure 7.3b, the difference in thermal storage and the heat demand balance are illustrated, where the heat demand balance is expressed as the heat demand minus the heat production. In EnergyPLAN the excess heat and waste incineration plant are operating on a constant basis and these are not connected to the thermal storage in EnergyPLAN. This is the reason why this results with excess heat production in the period between May and November, where the heat demand is lower from the heat produced from the waste incineration and the excess heat. However, in reality the operation of the waste incineration plant may be possible to be regulated and it is also possible that a thermal storage may exist, thus the heat production and excess heat may be stored. If it was possible to store the heat from these until it was needed, this could reduce the use of boilers in the system. However, this is also dependent on the size of the thermal storage and the heat losses from the storage.

The hourly electricity demand and the hydro capacity are presented in 7.4.

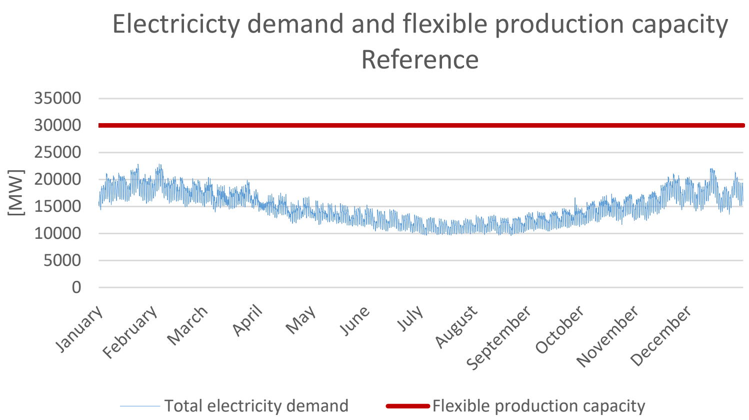


Figure 7.4: Relation between flexible production capacity and electricity demand in the Reference scenario. Own figure.

From figure 7.4, it can be seen that the electricity demand in every hour throughout the year is not exceeding the hydro power capacity, meaning that in theory there is possibility to produce more electricity, if export is needed.

Table 7.1 summarises the results for CO_2, total RES shares in the primary energy supply and in electricity, as well as the total annual cost for the Reference scenario.

Table 7.1: Results for CO_2 emissions, RES share and cost for the Reference scenario.

Variable	
CO_2 emissions [Mt]	98.343
RES share of PES [%]	28.7
RES share electricity [%]	143.3
Total annual costs [MNOK]	164 769

From table 7.1 it can be seen that the RES share of PES is relatively low when compared to the RES share for the electricity. This is due the inclusion of the transport and offshore sectors, which are primarily based on fossil fuels, which also accounts for the main share of CO_2 emissions in Norway. The total annual costs are subject to uncertainties in the cost inputs which are found in appendix A.4 and are further discussed in section 12.6.

Table 7.2 shows the import and export of electricity in the Reference scenario. In addition the number of hours with import and export of electricity have been calculated and added to the table.

Table 7.2: Import/export in reference scenario.

Variable	
Total import [TWh/year]	0
Number of hours with import [Hours]	0
Total export [TWh/year]	10.75
Number of hours with export [Hours]	5639

Lastly, the total electricity demand in the Reference scenario, including both individual electric heating and DH, is presented in table 7.3 along the maximum electricity load of the system in the year.

Table 7.3: Electricity demand in Reference scenario.

Variable	
Total electricity demand [TWh/year]	130.48
Total electricity demand individual heating [TWh/year]	31.11
Total electricity demand DH [TWh/year]	1.19
Max. electricity load [MW]	22882

DH scenarios 8

To be able to compare the effects a shift from individual electric heating to DH have, it is needed to construct scenarios where the change is implemented to compare it to the Reference scenario. A Reference scenario was constructed and analysed in chapter 7. One of the research questions in chapter 3 questions is how different combinations of production units will affect the operation of the system. In order to investigate this, at least two scenarios with differences in the production technologies need to be constructed.

Different implementations of production technologies are expected to give different results and therefore also different information about the operation of the Norwegian energy system. A shift from electricity to other sources of heating will give information about the effect of changing from electricity to other fuels. A shift from individual electric heating to district heating based largely on electricity will give information about the effect of going from individual heating to collective heating.

The following chapter seeks to describe and analyse the design of district heating scenarios for the shift from individual electric heating. Firstly, the production technologies are shortly described and analysed in relation to their potential for district heating production in Norway. This will form a basis for the design of scenarios. Furthermore, the different scenarios are constructed and analysed.

8.1 Production technologies

In the following section, different district heating production technologies are presented, and the potential for the different technologies in the Norwegian district heating system are considered. In addition, the way how EnergyPLAN prioritise the technologies in the production of DH is explained.

It is chosen to focus the analysis on the production units prioritised by Frederiksen and Werner [2013] in section 4.2, as well as also including electricity based production units and solar DH. The following units are therefore considered possible for implementation in the Norwegian district heating system in the following:

- CHP
- Waste incineration (CHP)
- Excess heat from industry
- Boilers with combustible renewables
- Geothermal heat
- Electric boiler/HP
- Solar thermal heating

8.1.1 Combined heat and power (CHP)

The idea behind combined heat and power is to produce and utilise both electricity and heat from a power plant and thereby achieve a higher total efficiency than traditional electricity or thermal only power plants [Frederiksen and Werner, 2013]. There are several types of CHP plants, several fuels that can be used and different modes of operation. EnergyPLAN differs between the modes of operation as well as the fuel input, as described in section A.2.

As described in section 2.3 the Norwegian electricity production is mainly based on production from hydro power plants, and the prevalence of traditional thermal power plants and CHP-plants is low. In section A.2 it was found, that there currently is only one large scale CHP plant in operation in mainland Norway with an electric capacity of 180 MW, but that this is to be decommissioned in 2018. This leaves only 100 MW electric capacity of small scale biomass CHP plants installed, excluding CHP plants based on waste incineration.

Even though there are advantages using CHP plants for district heating production, it could be discussed whether or not they should be considered as secondary sources for DH production if they are constructed simply for the production of heating. Norway is a country that has abundant hydro resources for electricity production, which limits the necessity of CHP plants for electricity production. However, if extra electric capacity is needed in the system, the addition of CHP plants would contribute to the electricity production. The CHP plants considered for the DH scenarios are only biomass based, as fossil fuels are currently being phased out in the European energy system. Biomass is, however, not an unlimited resource. It has been chosen only to consider nationally available biomass resources in this master thesis. The realistic potential for biomass in Norway, excluding waste for waste incineration, is 20-22 TWh [Melbye et al., 2014]. It could also be considered using imported biomass for the production of heat, however, this does contradict with the idea of using locally available resources for DH.

In EnergyPLAN when inputting CHP's under the technical simulation strategy 2, they are prioritised according to the electricity demand and not according to the heat demand. When used for DH, the CHP's are given priority after the solar thermal production units and excess heat. [Lund, 2014a]

8.1.2 Waste incineration

Recovery of heat from waste incineration, also known as waste-to-energy, is an old and common method of using energy from waste that would otherwise be wasted. Waste incineration plants are usually of a large size and the thermal energy from the plants can be used in district heating boilers, converted to electricity in thermal power plants, used in CHP plants or used to drive chillers used for district cooling. [Melbye et al., 2014]

Arguments against the use of waste incineration for production of hot water for district heating is, that the amount of waste should rather be reduced than used for energy purposes. Frederiksen and Werner [2013] presents a waste hierarchy on the most favoured options for waste management strategies, presented in the following order, from most to least favourable options:

1. Reduce
2. Reuse
3. Recycle
4. Energy recovery
5. Landfill

According to Melbye et al. [2014] waste is a resource that is characterised by high competition. This is partly due to the Norwegian and Swedish waste market being closely connected and there is larger waste incineration capacity than waste resources. Melbye et al. [2014] therefore estimates, that the potential for waste for waste incineration in Norway is already exploited through the existing waste incineration facilities. The potential is therefore the same as in input for the Reference scenario, 4.86 TWh/year. In EnergyPLAN, the waste incineration is prioritised after CHP. Furthermore, the waste incineration is not included in the thermal storage utilisation in DH, therefore a potential heat production that exceeds the heat demand would be lost. [Lund, 2014a] However, in reality it may be that thermal storage is connected and that the potential excess heat production is utilised.

8.1.3 Geothermal heat

The principle behind geothermal heat is to utilise the geothermal energy from the ground. The term geothermal energy is commonly used for both deep and shallow geothermal energy, where the deep energy is found at high temperatures at large depths underneath the surface of the earth, while shallow geothermal energy is low temperature heat found in the upper part of the Earth's crust [Fornybar.no, N.D.]. Deep geothermal energy originates from the Earth's core and from the the decomposition of radioactive materials in the Earth's crust, and is found at depths larger than 300 m. Shallow geothermal energy is found at shallow depths, ranging from 0-200 m, and originates from stored solar heat in the ground [Frederiksen and Werner, 2013]. According to Frederiksen and Werner [2013] there is a discussion whether shallow geothermal heat could actually be classified as geothermal heat, since it does not originate from the Earth's core, but from solar energy stored in the ground. The potential for deep geothermal heat has large geographical variations, and the variations in Europe can be seen illustrated in figure 8.1.

From the map, it can be seen that the deep geothermal energy potential in Norway is limited compared to other places in Europe. According to Frederiksen and Werner [2013] the limited potential found in Scandinavia, is due to bedrock lying close to the surface in the Scandinavian peninsula. This makes the thermal gradients small which is unfavourable for the exploitation of geothermal energy in the area. That there is a limited deep geothermal potential in mainland Norway is also supported by a research group for geothermal energy in relation to the national strategy for research, development, demonstration and commercialising of new energy technology - Energi21 [Energi 21, 2010]. In order for deep geothermal energy to be feasible on mainland, a further development of the technology is needed [Energi 21, 2010]. In 2015 there were no deep geothermal installations in operation in Norway [Midttømme et al., 2015]. Because of the limited potential for deep geothermal energy in Norway, this is not considered further in this master thesis.

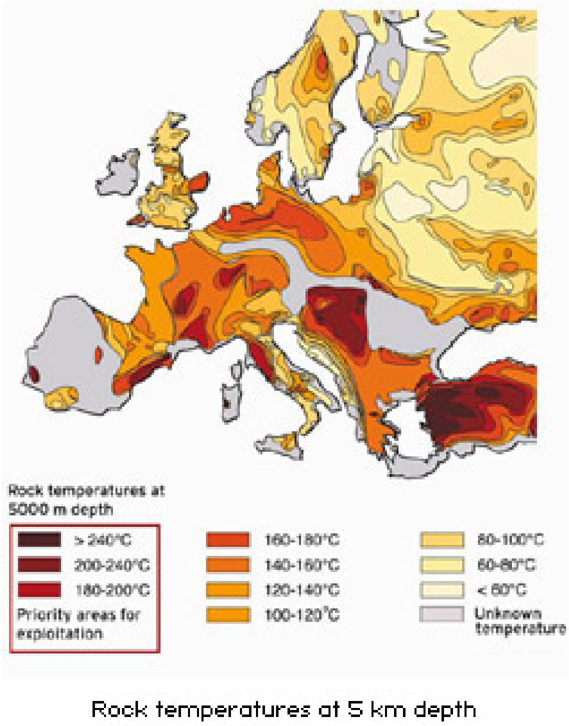


Figure 8.1: Deep geothermal potential in Europe. Figure from European Commission [N.D.].

Even though the deep geothermal potential in Norway is limited and difficult to exploit with the currently available technology, it is still possible to look at the exploitation of shallow geothermal energy in Norway. Shallow geothermal energy can be utilised in geothermal heat pumps, which is what the main share of geothermal energy in Norway is based on [Lund and Boyd, 2015]. According to Energi 21 [2010] shallow geothermal heat can also be found in ground water in Norway, with a temperature of 4-8°. In this master thesis, shallow geothermal energy has only been considered utilised as ambient heat sources for compression heat pumps in DH, but these are not separated from other heat sources. It should however be kept in mind, that there is not an unlimited area available for the installation of geothermal HP's and this may limit the potential. A further description of heat pumps for DH can be found in section 8.1.6

8.1.4 Solar thermal

Solar thermal units used for the production of heat in DH systems are usually ground or roof/facade based thermal collectors which utilise the solar radiation in the production of heat. The production from solar thermal DH is not controllable unless installed in combination with a thermal storage. [Frederiksen and Werner, 2013]

It has been difficult to estimate the potential for solar heating in DH in Norway. In theory, the potential is limited by the area available for installation and the solar radiation in these areas. There are reports available for calculations of solar energy potential, however, these are often based on the estimation of potential roof areas where solar heating panels or PV panels potentially can be installed. In theory, there is no reason why roof areas cannot be used for solar DH units, but it is not known if this will be utilised for DH in Norway. Currently, there is only one large scale solar heating facility producing heat for DH in Norway. The Norwegian district heating association (Norsk Fjernvarme) and the Solar energy association (Norsk Solenergiforening) are currently working on mapping the potential for solar heating for district heating in Norway [Norsk Fjernvarme, N.D.b]. It is chosen, not to look further into the potential for solar heating in Norway in this master thesis, but rather include the effects of implementing solar heating in the sensitivity analysis in chapter 10. An additional reason for not looking further into an expansion of solar heating when designing the DH scenarios is that it is a fluctuating renewable resource and it is difficult to pinpoint exactly what capacity is needed, as this is dependent on the solar radiation through the year.

8.1.5 Excess heat from industry

Excess heat from industry is according to Frederiksen and Werner [2013] one of the most fundamental heat sources in a DH system as this is heat that would otherwise be lost. The excess heat from industry could be also used by recycling it and reusing it on site either for industrial processes or heating purposes of the industrial buildings. However, in this thesis the excess heat is used only as a heat source for DH and whatever is used locally on site is not considered.

In a report concerning the potential for efficiency improvements in industry from 2009, Enova [2009] estimated that there was a potential for the Norwegian industry to sell 10 TWh of excess to for example district heating plants. It is not known what temperature this heat has. Furthermore, it is not known if this excess heat is located in proximity to DH networks or what would be the potential cost of purchasing this heat from the industries. However, for the purpose of this master thesis, it is considered that the heat can be used directly, free of charge in the DH networks. In EnergyPLAN, the excess heat is prioritised right after the solar thermal units but before CHP's. It is also not connected to the thermal storage of the DH system, although in reality this could be done.

8.1.6 Electric boilers and heat pumps

In the production of heat in DH systems, both electric boilers and heat pumps could be used when there is excess electricity production in an energy system. They also could be used when electricity prices are low, which also usually is connected to excess electricity production. Another utilisation of these in DH systems could be for peak load. In Norway, there are DH systems that use electricity driven production units to deliver heat due to the large hydro power production in the country and relatively low electricity prices as mentioned in 6.2. [Frederiksen and Werner, 2013]

The potential of electric boilers and heat pumps is limited by the electricity available. Furthermore, the heat pump potential may be limited by area available for installation of geothermal HP's. However, these potential limits are not considered further in this master thesis. In EnergyPLAN, the only possibility of inputting electric boilers is for use when there is critical excess electricity production in the country. It is however assumed that electric boilers in Norway also are used in other situations, and placing them only in the

CEEP regulation strategy would not give an accurate picture of how the electric boilers are used in the system. HP's are, in the chosen technical regulation strategy 2, used together with CHP units to cover heat demand and balance electricity supply and demand. It is assumed that treating the electric boilers as HP's with a COP of 1 would give a more accurate representation of the use of electric boilers in Norway. In this master thesis, both HP's and electric boilers are therefore treated as compression heat pumps where the COP is used to represent the share of boilers and HP's in the system. The consequence of this is, however that the priority of HP's and boilers are the same. The combination of boilers and HP's are simply referred to as HP in this master thesis. The calculation method for the combined COP can be seen in appendix A.2.3.

8.2 Design of DH scenarios

As described in the introduction to this chapter, the purpose of the chapter is to construct scenarios representing a shift from individual electric heating to DH using different production technologies and analyse the effects on the operation of the Norwegian energy system.

The research question only focuses on how a shift from electric heating to DH affects the operation of the energy system, it does not specify how large a share of electric heating is to be replaced by DH. Different amount of heat displacement is, however, expected to give different results for the operation of the energy system.

Table 8.1 presents different shares of displacement and the resulting electricity consumption, total individual electric heating, individual electric heater, individual heat pump and DH demands. It is chosen to firstly move demand from individual electric heaters to district heating instead of from heat pumps, as the efficiency for heat pumps is higher than for electric heaters. It is chosen to move 25%, 50% and 100% of the individual electric heat demand. This is not necessarily realistic, and whether or not these shifts are realistic is discussed further in chapter 12.

Table 8.1: Heat displacement.

Displacement	**Total elec. consumption [TWh/year]**	**Total indv. elec. heating [TWh/year]**	**Indiv.elec. heaters [TWh/year]**	**Indv. HP [TWh/year]**	**DH prod. [TWh/year]**
Reference - 0%	129.012	31.1	24.6	6.52	5.44
25%	121.24	23.32	16.82	6.52	14.20
50%	113.46	15.55	9.05	6.52	22.97
100%	97.91	0	0	0	50.04

As can be read from the table, a replacement of individual electric heating with district heating increases the DH production to 50 TWh in the 100% displacement. This also decreases the total electricity consumption. This of course will be the case when the individual electric heating is displaced with another sources of heat besides electricity.

The inputs for individual HP in table 8.1 represent the electricity used for heating, where 6.52 TWh produces 15 TWh of heat.

The shifts are implemented in EnergyPLAN through adjusting the total electricity demand, the electricity demand for heating and the DH demand. Furthermore, the distribution files used for the DH demand are kept as in the Reference scenario, as it is assumed the distribution is the same. In the distribution files for electricity demand it is taken into account that a share of the electricity demand is shifted to DH and this share is removed from the distribution files for the electricity demand.

All production technologies evaluated in the design chapter are listed in table 8.2. It should be noted that the potential biomass for CHP and biomass boilers shown in the table is the total potential fuel input and that if the full potential is used in one of them it excludes the use in the other.

Table 8.2: Potential production technologies for DH scenarios.

Technology	**Potential fuel input in DH [TWh/year]**	**Storage connection**	**Primary/ Secondary**
Biomass CHP	20-22	Yes	Secondary
Waste incineration	4.86	No	Secondary
Excess heat	10	No	Secondary
Geothermal	N/A	No	Primary
Biomass boiler	20-22	Yes	Primary
Solar heating	N/A	Yes	Primary
Electric boiler	N/A	Yes	Primary
HP	N/A	Yes	Primary

The amount of DH demand also affects which production technologies can be used for the production of district heating. Some of the district heating production technologies are limited by their potential, as can be seen in table 8.2. They are also evaluated according to their storage connection in EnergyPLAN, as it is seen that some technologies are not possible to be included in the thermal storage. Furthermore, the technologies are considered as either primary or secondary heat sources according to Frederiksen and Werner [2013] as mentioned in 4.2. The secondary sources are used to first cover the base load in the DH scenarios.

Both biomass CHP and biomass boilers are limited to a maximum of 22 TWh fuel input in total. The potential of excess heat from industry is according to Enova [2009] 10 TWh, and it was chosen to utilise this potential to cover the remainder of the base load after solar thermal and waste incineration. As was described in the previous sections, it is assumed that the waste incineration is utilised to its full potential already in the reference scenario. It was chosen not to put a potential on the solar thermal production as this production is fluctuating and depending on the solar radiation and available area for panels.

Furthermore, waste potential is kept also as in the Reference scenario and as the solar thermal potential is unknown, the already existing production unit is kept again from the

Reference scenario.

For the DH system to be able to respond to changes in the heat demand, a combination of technologies is needed, including units covering the demand exceeding the base load and can cover peak loads. It is in this master thesis chosen to focus on two scenarios: one using HP's to cover the remainder of the load and one using biomass. Both scenarios are investigated for a 25%, 50% and 100% shift from individual electric heating to DH and are further described in the following.

8.2.1 Sizing of units for Bio scenario

The biomass based scenario, from now on referred to as the Bio scenario, is designed based on the available biomass resources in the country. It is chosen to design a biomass based scenario to investigate the effect of changing from electricity for heating to other fuels.

In order to be able to test the 25%, 50% and 100% shifts from individual electric heating to DH highly based on biomass, utilising the full biomass potential in the country, first the biomass based production units need to be sized. In order to size them the base, average and peak loads of the heat demand in the different shifts are calculated. They are seen in table 8.3.

Table 8.3: Sizing of production units Bio scenario.

Parameter	25% shift
base [MW]	562
Average [MW]	1 625
Peak [MW]	3 276
Ref. Waste [MW]	350
Ref. ex. heat [MW]	21
Ref. HP [MW]	437
Ref. boilers [MW]	518
Ref. biomass CHP [MW]	275
Additional ex. heat [MW]	191
Additional Biomass boiler [MW]	1 484
Buffer biomass boiler [MW]	655

As can be seen from table 8.3, the Bio scenario is only designed for a 25% shift from individual electric heating to DH. This is due to limitations in the potential of biomass within the country. A Bio 50 and Bio 100 scenario would use more biomass than what is the potential within the country, and they are therefore not investigated further in this master thesis.

The table shows the thermal outputs of the production units. It is chosen to keep the capacity of production units from the reference scenario. The reason for not increasing the thermal output capacity of the biomass CHP is due to the biomass CHP not being strictly operated to cover the heat demand, but also used to balance out the electricity demand.

Upon investigation, it was found that even the biomass CHP from the reference scenario would have less than 1 500 operational hours compared to the 5 600 operational hours that biomass CHP's are designed to have according to NVE [2015]. It is therefore chosen to base the biomass scenario only on biomass boilers in addition to the already existing production units and an increase in the excess heat used to cover base load.

It can be seen from table 8.3 that a buffer biomass boiler capacity is included. This biomass boiler capacity is included to secure security of supply also in very cold years, and is designed to cover 20% additional to the peak demand.

The production units covering the heat demand in the Bio 25 scenario are better illustrated in figure 8.2. Note that the base, average and peak load are illustrated as black thick lines.

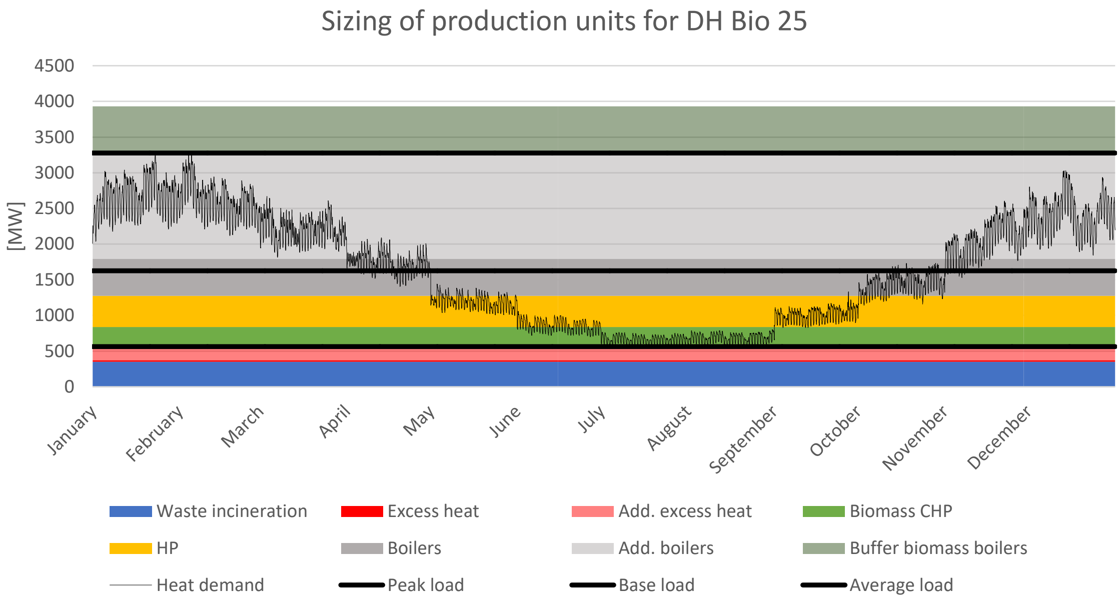


Figure 8.2: Design of Bio 25 scenario. Own figure.

The units in figure 8.2 are ordered according to EnergyPLAN's prioritisation of production units to cover the heat demand. Semi transparent fields represent capacity that is added to the system, while the opaque represents capacity that was included in the reference scenario. The figure shows how the base load is covered by waste incineration and excess heat, while the biomass CHP and HP capacity is not enough to cover the average load. The remainder of the load is covered by the existing boilers from the reference scenario and additional biomass boilers to cover peak demand. The semi transparent green field represents the over dimensioned boiler capacity that are included to increase security of supply in cold years. It should be pointed out, that if all boiler capacity including the extra 20% capacity is utilised, the biomass used may exceed the biomass available within the country and create a need for import.

8.2.2 Sizing of units for Electric scenario

In the Electric scenario individual electric heat demand is moved to DH and the additional production capacity needed is covered by HP's. HP's are in this master thesis referred to the capacity of both heat pumps and electric boilers in DH, however, only additional heat pumps are added in the system and the capacity of electric boilers remain unchanged. In EnergyPLAN this is represented by increasing the COP of the HP to reflect a larger share being heat pumps with a COP of 3.

The Electric scenario, as mentioned before, is highly based on electricity driven production units. Table 8.4 shows how are the production units sized in the different shifts of the Electric scenario, and also included the new calculated total COP of the of the total HP.

Table 8.4: Sizing of production units Electric scenario.

Parameter	**25% shift**	**50% shift**	**100% shift**
base [MW]	562	907	1 972
Average [MW]	1 625	2 623	5 705
Peak [MW]	3 276	5 292	11 515
Ref. Waste [MW]	350	350	350
Ref. ex. heat [MW]	21	21	21
Ref. HP [MW]	437	437	437
Ref. boilers [MW]	518	518	518
Ref. biomass CHP [MW]	275	275	275
Additional ex. heat [MW]	191	536	117
Additional HP [MW]	1 484	3 155	8 797
Buffer biomass boiler [MW]	655	1 058	2 303
HP COP [-]	2.34	2.60	2.83

The base, average and peak loads in the heat demand in the Electric 25 scenario are naturally the same as in the Bio 25 scenario as the same amount of electric heating demand is shifted to DH. As in the Bio scenario, the already existing production units from the Reference scenario are kept, and buffer biomass boilers are added corresponding to 20% of the peak demand to ensure security of supply. Naturally, the combined COP of the HP increases when additional heat pump capacity is added and the boiler capacity remains the same as in the reference scenario.

The sizing of units for the Electric 25 scenario is illustrated in figure 8.3.

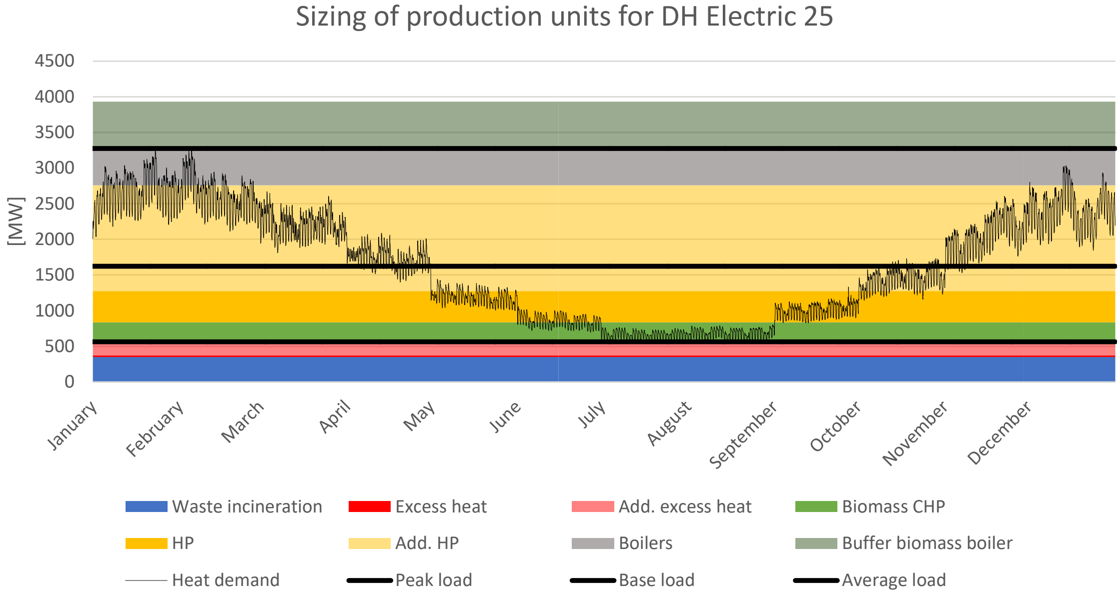


Figure 8.3: Design of Electric 25 scenario. Own figure.

In figure 8.3 it can be seen that the amount of excess heat in the scenario is increased so that waste incineration and excess heat cover the base load. The additional HP units are sized to cover the remaining demand after the base load and the additional capacity from the reference scenario.

In figure 8.4 the sizing of units for the Electric 50 scenario can be seen.

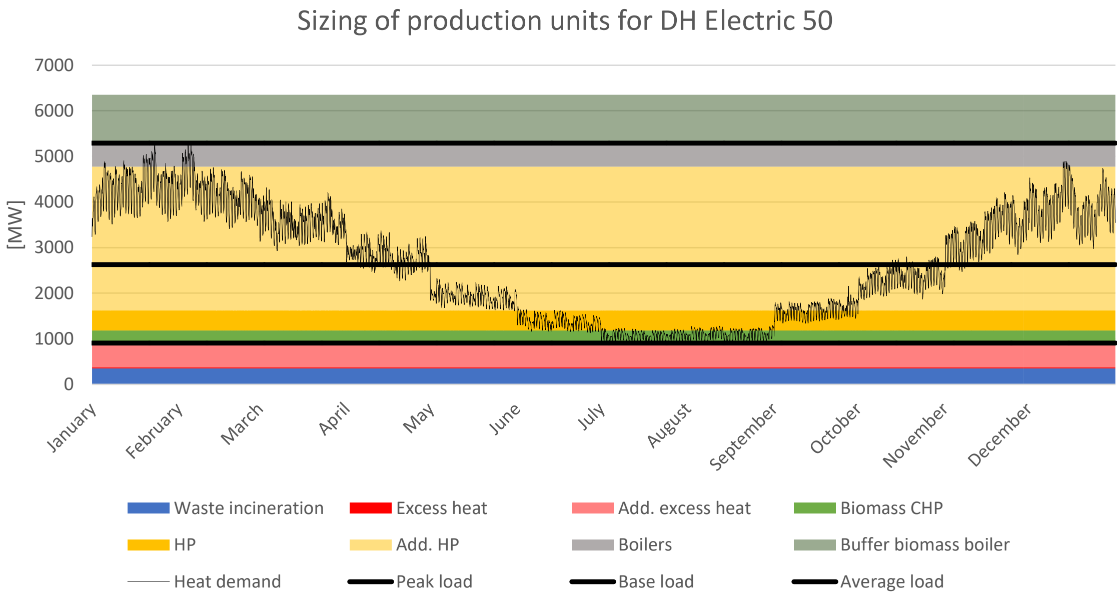


Figure 8.4: Design of Electric 50 scenario. Own figure.

As seen in figure 8.4, the base load is covered by the waste incineration and excess heat.

Again, the HP capacity is added to cover the remainder of the load, utilising the boilers from the reference scenario as peak load boilers. Again, extra biomass boiler is added for security of supply, amounting to 20% of the peak load.

Lastly, the 100% shift from individual to DH electric heating is done, which is illustrated in 8.5.

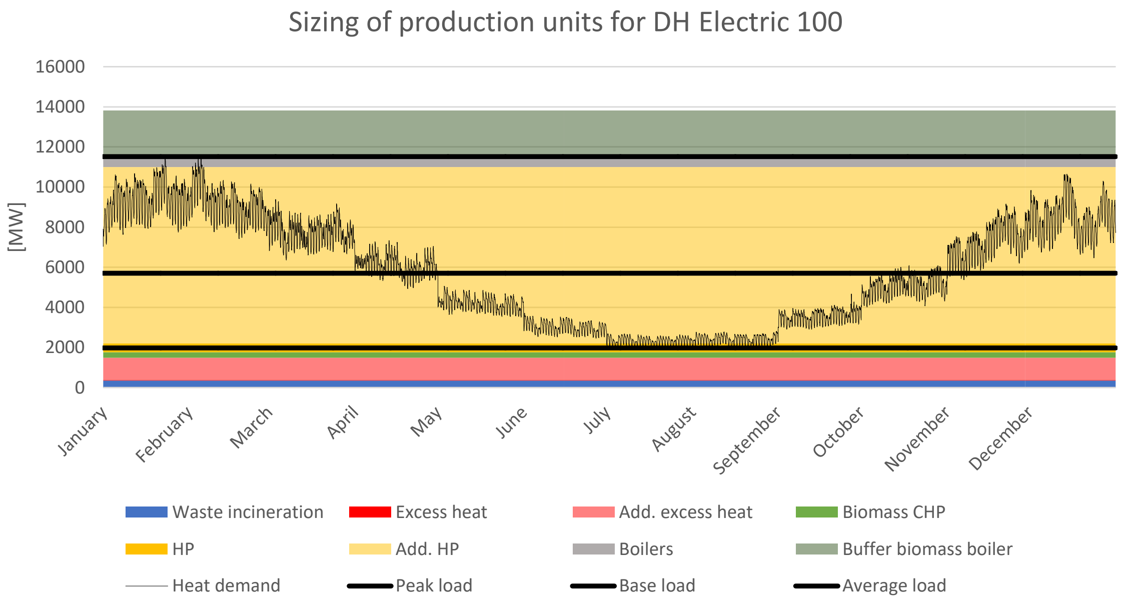


Figure 8.5: Design of Electric 100 scenario. Own figure.

The DH demand in the Electric 100 scenario is increased so much that the excess heat potential available is not able to cover the base demand. The already existing HP and biomass CHP capacity is therefore also needed to cover the base load after utilising the full excess heat potential. The remainder of the load is covered by adding new HP capacity and using boilers from the reference scenario to cover the peak demand. Also in this scenario, additional boiler capacity is added for security of supply.

Thermal storages are implemented in all scenarios to maximise the use of HP's and minimise the use of boilers for DH production. The storages are sized for this purpose using an approach where the storage size is found at the point with highest HP production and lowest boiler production. The resulting storage sizes are seen in table 8.5.

Table 8.5: Sizing of thermal storage for all scenarios.

Scenario	**Storage size [GWh]**
Reference	1
Bio 25	4.3
Electric 25	9.3
Electric 50	6.4
Electric 100	2.1

From table 8.5 it can be seen that the need for storage increases in all scenarios compared to the reference scenario. In the Electric scenarios it can be seen that the storage is smaller the higher the heat demand and the larger the share of HP's. This is potentially due to the increased share of HP capacity compared to other production capacity making the HP's able to cover a larger share of the peak demand and in that way decreasing the need for boilers. In the Bio 25 scenario the storage is smaller than in the Electric 25 scenario even though the demand is the same. This is due to the HP capacity being lower and the HP not being able to decrease the boiler production further.

The scenarios are simulated in EnergyPLAN using the technical simulation strategy balancing both heat and electricity demands, and the results are presented in the next chapter.

Results from simulation of scenarios 9

In the following chapter the results from the simulation of the scenarios constructed for a shift from individual electric heating to DH are presented and analysed. The purpose of the analysis is to investigate the effect a shift to DH has on the operation of the Norwegian energy system.

As described in section 5.3.1, a technical simulation balancing both heat and electricity demands, is chosen to simulate the operation of the Norwegian energy system. This simulation strategy was also chosen for the Reference scenario which was presented in chapter 7. In the following, the results are presented and compared between the different scenarios and the Reference scenario.

9.1 Heating

All scenarios constructed for DH shift between 25% and 100% of the individual electric heating to DH. Naturally, this has an effect on both the individual heating demand as well as the DH demand. Figures 9.1 and 9.2 show the production of individual heating and DH divided on the different production units.

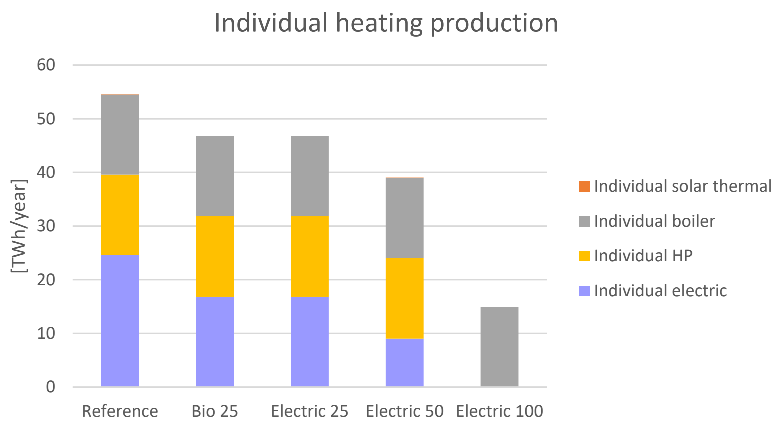


Figure 9.1: Individual heating production per production unit. Own figure.

In figure 9.1 it can be seen that the individual heating demand decreases as it is shifted from electric heating to DH and that the share of electric heaters of the total individual heat demand is increased. Furthermore, it is seen that a shift from individual HP to DH is only done in the Electric 100 scenario, as it is assumed that individual HP's are more efficient than direct electric heating and therefore would be replaced last.

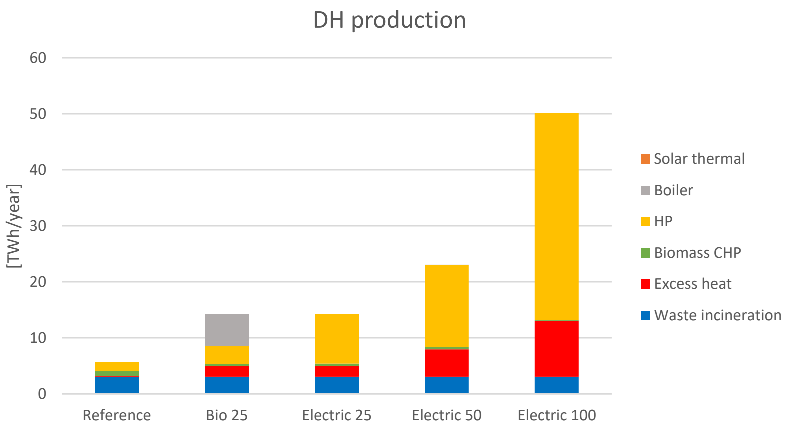
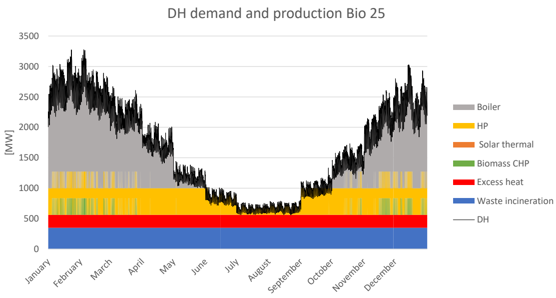


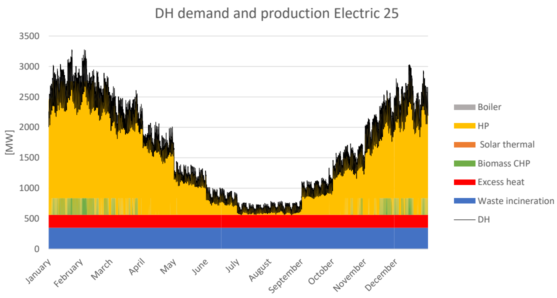
Figure 9.2: DH production per production unit. Own figure.

It can also be seen in figure 9.2 that the production of DH naturally increases as a larger share of heat demand is shifted to DH. Furthermore, it can be seen that the production from waste incineration is constant in all scenarios, as its production is constant and has not been changed in any of the scenarios. The production from the biomass CHP is also relatively stable in all scenarios, even though the heat demand is changed. This is due to the biomass CHP being regulated according to the electricity demand first and not the heat demand. The use of excess heat is also increasing when larger share of individual electric heating is moved to DH as the excess heat from industry, waste incineration and solar thermal are used to cover the base loads in all DH scenarios. As the heat demand in DH is increasing so does the excess heat. However, the full potential of the excess heat is used only in the Electric 100 scenario. In the Bio 25 scenario, the additional demand is covered by biomass boilers and HP, so that even though the scenario was designed to have boilers cover the peak demand, the contribution from HP's is also increased although the capacity of the HP's is not increased from the Reference scenario. This is due to EnergyPLAN prioritising the use of HP's before the use of boilers. Therefore, the boilers only run in hours where the HP's run at full capacity. For the Electric scenarios it can be seen that the added DH demand is covered by HP's which were also the units that were added to the system as described in section 8.2.

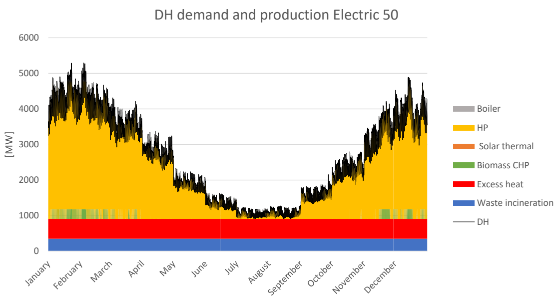
Figures 9.3a to 9.3e show how the different production units cover the DH demand.



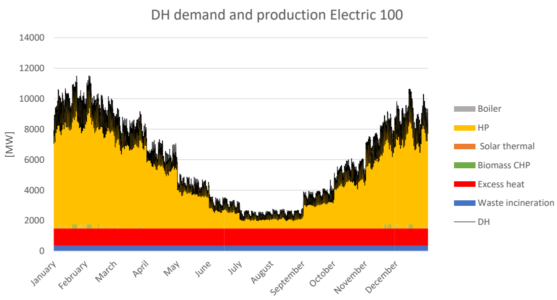
(a) Bio 25



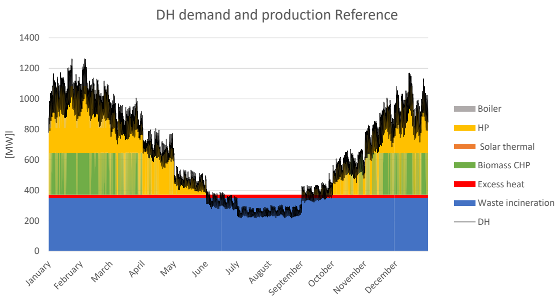
(b) Electric 25



(c) Electric 50



(d) Electric 100



(e) Reference

Figure 9.3: Production of DH divided on different production units and DH demand. Own figure.

From the figures in figure collection 9.3 it can be seen that there is a difference in how the different units operate to cover the DH demand. Compared to the Reference scenario, in all other scenarios there is no constant production from the waste incineration and solar DH that is not possible to be utilised in the DH system. It can be seen that the production of heat from the excess heat from industry is used to cover the rest of the base loads after waste incineration and solar thermal and is increasing with the larger share of individual electric heating is being moved to DH. Furthermore, there is an overproduction in some hours where the storage is filled and an underproduction in others, where the storage is drained.

It is difficult to see from the figures exactly how the relation between the production units have changed, and the specific numbers are therefore given in table 9.1.

Table 9.1: DH production on different units.

Variable	Bio 25	Electric 25	Electric 50	Electric 100	Reference [TWh/y]
Waste incineration [TWh/year]	3.07	3.07	3.07	3.07	3.07
Excess heat [TWh/year]	0.18	1.86	1.86	4.89	10
Biomass CHP [TWh/year]	0.39	0.48	0.44	0.15	0.83
Solar thermal [TWh/year]	0	0	0	0	0
HP [TWh/year]	3.25	8.81	14.62	36.89	1.6
Boiler [TWh/year]	5.7	0.04	0.01	0	0.03

From table 9.1, it can be seen that in all scenarios, the production from the biomass CHP is decreased compared to the Reference scenario. This is likely due to a decrease in electricity demand for which the CHP units are operated as in the Electric scenarios the COP of the HP's used for DH is increased with the increase from the individual electric heating shift. Furthermore, the increase of excess heat decreases the amount of HP's needed for the shift. In the Bio 25 scenario the use of CHP is lower than in the Electric 25 although the same amount shift was made. This is due to the shift in the Bio 25 which is based on biomass boilers, and the HP's used in this scenario being the same amount with the same COP as in the Reference scenario. Furthermore, it is seen that the boiler production is reduced in the scenarios where there is a large increase of DH demand and a larger share of the demand is covered by HP's.

As was described in section 8.2 the size of thermal storage is scaled differently in all scenarios to minimise the production on boilers and maximise the production on HP. The operation of the thermal storage in the different scenarios is not investigated in this chapter but it is discussed in 12.

9.2 Electricity

In the following section, the results regarding the electricity production, demand and exchange for the four scenarios are presented and analysed and compared to the Reference scenario.

Table 9.2 shows the different shares of electricity production for the different electricity producing units.

Table 9.2: Electricity production on different units.

Variable	Bio 25	Electric 25	Electric 50	Electric 100	Reference
Dammed hydro	133.57	133.57	133.57	133.57	133.57
River hydro	4.88	4.88	4.88	4.88	4.88
Pumped hydro	0	0	0	0	0
Wind	2.12	2.12	2.12	2.12	2.12
Waste incineration	0.35	0.35	0.35	0.35	0.35
Biomass CHP	0.14	0.17	0.16	0.05	0.30
PV	0.01	0.01	0.01	0.01	0.01

From the table it can be seen that the only electricity production changed between the scenarios is from the biomass CHP. The production on the CHP is lower in all scenarios compared to the Reference scenario. This is due to the decreased electricity demand in the DH scenarios.

Table 9.3 summarises the electricity demand and maximum electricity load in all scenarios.

Table 9.3: Electricity demand in the DH scenarios and Reference scenario.

Variable	Bio 25	Electric 25	Electric 50	Electric 100	Reference
Total electricity demand [TWh/year]	123.94	125.28	119.36	111.19	130.48
Total electricity demand individual heating [TWh/year]	23.34	23.34	15.56	0	31.11
Total electricity demand DH [TWh/year]	2.72	3.77	5.62	13.02	1.19
Max. electricity load [MW]	19 731	20 227	20 461	18 558	22 882

As can be read from table 9.3, the total electricity demand, excluding export, is highest in the Reference scenario. In the Electric 25 and Bio 25 the electricity demand is lower than in the Reference as some of the individual electric heating is shifted to either biomass as a fuel in the Bio 25 scenario or to HP for the Electric 25 scenario. However, the added HP's in the Electric 25 scenario are with higher COP than in the Bio 25 as in the Electric scenarios only HP's are added to the existing HP capacity in EnergyPLAN, which originally has lower COP due to the mix of electric boiler and HP's. This results with lower electricity demand for the Electric 25 compared to the Bio 25. The electricity demand in the Electric 50 and Electric 100 scenarios is therefore decreasing due to the increasing COP of the added HP's in these scenarios. If the COP of the HP's in the DH was changed it is also expected that the electricity demand in all Electric scenarios will change. The effect of the HP's COP will be investigated further in chapter 10. Furthermore, it can be seen that in all scenarios, there is a relation between the total electricity demand and the maximum electricity load - a higher electricity demand gives a higher maximum electricity load. This is an effect of using the same distribution file for electricity as a basis for both the electricity demand and heat demand in all scenarios. If other data on heat demands were available or other distribution files were created for the DH it is not certain that this result would be the same.

In section 4.3 it was defined that the total import/export as well as the number of hours with import/export can give an indication about the flexibility within the Norwegian energy system. A lower import/export would indicate a higher flexibility in the system. The results for import/export in the system are presented in table 9.4.

Table 9.4: Import/export in all scenarios.

Variable	**Bio 25**	**Electric 25**	**Electric 50**	**Electric 100**	**Reference**
Total import [TWh/year]	0	0	0	0	0
Number of hours with import [Hours]	0	0	0	0	0
Total export [TWh/year]	17.13	15.82	21.73	29.79	10.75
Number of hours with export [Hours]	7 345	6 927	7 096	8 190	5 639

It can be seen that in the Electric scenarios a higher total export of electricity equals a larger number of hours with export. The situation is however not the same in the Bio 25 scenario, where the total electricity export is lower than in the Electric 50 scenario but the number of hours with export is higher. This is most likely due to the Bio 25 using a combination of HP and boilers to cover the DH demand. EnergyPLAN seeks to use HP before running on boilers, and when there is a lower capacity of HP in this scenario, the boilers will necessarily be used in more hours. At the same time, the total electricity demand in the country is higher in the Bio 25 scenario, and therefore the total electricity needed to be exported is lower than in the Electric 50 scenario.

One could argue that the large capacity of controllable dammed hydro should be able to respond to the electricity demand and avoid export. However, it is is seen that in hours with export there is still production by dammed hydro power. It is believed that this is due to a need to drain the storage in order to make room for the inflow to the storage. This could prove to be a sign of inflexibility, as the ability to control the dammed hydro power depends also on the storage content and the natural inflow to the storage.

One of the effects that is to be investigated for this master thesis is the potential to free up capacity that can be used for export production, and thereby increasing the potential for Norway to function as a virtual green battery for Europe. In figure 9.4 the electricity demand in the different scenarios can be seen along with the hydro power capacity.

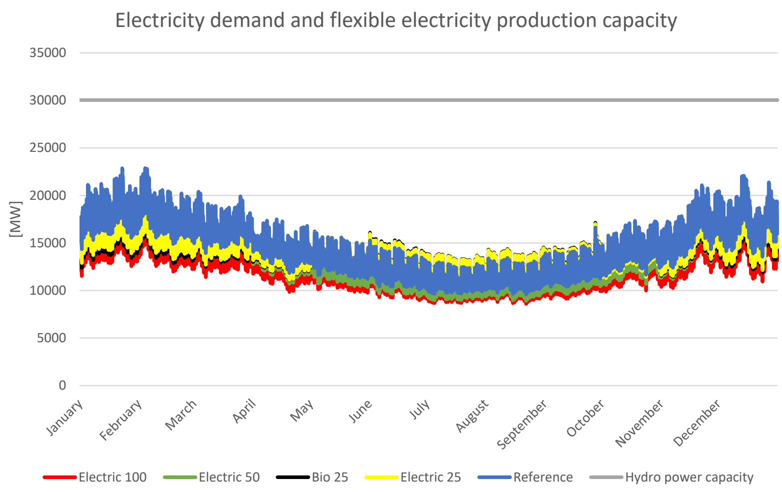


Figure 9.4: Relation between hydro power capacity and electricity demand in the Reference and DH scenarios.

From figure 9.4 it can be seen that in the Bio 25 and Electric 25 scenarios the demand is reduced in winter and increased in the summer compared to the Reference scenario. Furthermore, it can be seen that the Electric 50 has a lover electricity demand in the summer and Electric 100 has the lowest electricity demand all year. This shift in total electricity consumption is most likely due to several change between the Reference scenario and the DH scenarios. The introduction of a larger share of excess heat in the DH sector reduces the overall demand through the year. Furthermore, the COP of the HP's has an influence on the electricity demand through the year. The reason for the Bio 25 evening out the electricity consumption in winter and summer is due to a share of the production of DH in winter is on biomass boilers.

From this it can be concluded that, in the Electric 100 scenario, shifting 100% from the individual electric heating to DH increases the potential of the electricity production capacity that could be exported to Europe. Table 9.5 summarises the number of hours in each scenario where available electricity production capacity is lower than the transmission line capacity.

Table 9.5: Relation between hydro power capacity and electricity demand.

Variable	**Bio 25**	**Electric 25**	**Electric 50**	**Electric 100**	**Reference**
Hours with free capacity<8 895 MW	0	0	0	0	147

From table 9.5 it can be seen that in all DH scenarios besides the Reference scenario it is possible to export at full capacity in all hours of the year. In the Reference scenario, the number of hours with free capacity lower than the transmission line capacity is 147. This does not necessarily mean that it is not possible to export at all, only that it is not possible to export at full transmission line capacity.

9.2.1 Emissions, RES share and costs

As explained in chapter 1, Norway is bound by the EU 2020 goals to reduce CO_2 emissions and achieve a certain RES share. It is therefore relevant to investigate what effect a change from individual electric heating to DH has on the emissions and the RES share in the Norwegian system. Furthermore, the costs of a system are an important factor as to whether or not investments should be made.

Table 9.6 presents resulting emissions, RES shares and costs of the different scenarios compared to the Reference scenario. The lowest emissions, highest RES shares and lowest costs are marked in bold.

Table 9.6: Results for emissions, RES share and cost for DH scenarios.

Variable	**Bio 25**	**Electric 25**	**Electric 50**	**Electric 100**	**Reference**
CO_2 emissions [Mt]	98.273	98.235	98.223	**98.13**	98.343
RES share [%]	**29.6**	28.7	28.7	28.7	28.7
RES share electricity [%]	141.5	139.6	137.1	127.9	**143.3**
Total annual costs [MNOK]	168 191	165 141	165 407	167 171	**164 769**

As can be seen from the table, the scenario with the lowest CO_2 emissions is the Electric 100, where 100% of the individual electric heating is shifted to electric DH. This could be explained with the decreased amount of boilers usage, which operate on fossil fuels as well as biomass, compared to all other scenarios. This trend of decreasing the CO_2 emissions is seen with the increased use of HP's too. This is true for the Bio 25 as well, although the same amount of HP's with the same COP from the Reference scenario were used. However, the HP's in the Bio 25 are used more than in the Reference scenario as it was seen in 9.1.

Furthermore, it can be seen that the overall RES share is unchanged from the Reference scenario in all three Electric DH scenarios, while the RES share is higher in the Bio 25 scenario. The reason is that the overall share of renewable energy production is increased when introducing additional biomass boilers compared to the use of fossil fuels.

The RES share of electricity is highest in the Reference scenario. This is due to the ratio between the RE electricity production and electricity consumption. The ratio is higher in the Reference scenario than in any other scenarios. The only difference is the Bio 25 where the RES electricity production units are still the same but the electricity demand is slightly decreased.

The total annual costs are the lowest in the Reference scenario. The reason for this is that in the DH scenarios, the costs of production units for DH and the DH network and substations are higher than the costs of production units for individual electric heating. The total annual costs are highest in the Bio 25 scenario due to the increased use of biomass and low export of electricity compared to the other DH scenarios.

9.3 Summary of results

In general, it was seen from the results of the simulation of the scenarios that the change from individual electric heating to DH did change the operation of the Norwegian energy system to a certain extent.

In terms of the electricity demand, all DH scenarios reduced the total electricity demand in the country. In the Bio 25 scenario this was due to shifting to biomass as fuel for heating. In the Electric scenarios the decrease in electricity demand was most likely due to a higher efficiency of the HP's in these scenarios than the individual electric heating. The lower electricity demand also resulted in a lower maximum electricity load in all scenarios. In figure 9.4 it was seen that all DH resulted in a larger difference between electricity demand and flexible production capacity in winter months. In summer months, the Bio 25 and Electric 25 scenarios resulted in a smaller difference in summer months. However, all scenarios resulted in differences larger than 8 895 MW in all hours of the year, indicating that it is possible to utilise the full export capacity to Europe in all hours. This serves as an argument for DH being able to increase the possibility of providing flexibility to Europe.

Even though the shift to DH had an effect on electricity demand, it did not have a significant effect on the electricity production. The only electricity producing unit that had a variation in total yearly production between the scenarios was the Biomass CHP. It was seen that the biomass CHP had a lower yearly production the lower the total electricity demand. The dammed hydro power facility did not respond to the decrease in demand by reducing the production, most likely due its need to regulate the storage content according to the natural inflow. Consequently, the export was increased in all DH scenarios, indicating that the Norwegian energy system lacks the flexibility to respond to the decrease in demand.

If looking at the overall system, the effect on CO_2 emissions are minimal, as the electricity production in Norway is highly based on renewable hydro power. The minimal changes there are in emissions are due to the decreased use of natural gas for DH production, where the Electric 100 scenario has the lowest emissions due to it having close to no heat production on boilers for DH.

There is a change in total annual costs between the different scenarios, where the Reference scenario has the lowest total annual cost. A change to DH will therefore in all cases entail an increase in total annual costs for the Norwegian energy system. This is due to investment costs both in production technologies but also in distribution technologies for DH, such as DH pipelines.

The results for the simulation of the operation of the scenarios are dependent on all modelling choices that are made, both in the modelling of the Reference scenario which is the basis for all other scenarios, as well as the choices made in the design of DH scenarios. Some of these choices are analysed in a sensitivity analysis in the next chapter.

10 Sensitivity analysis

Several decisions where made when constructing the Reference scenario and the different DH scenarios that have been used for simulations of the operation of the Norwegian energy system and analysed in the previous chapters. Making these decisions may have an influence on the operation of the Norwegian energy system, and the purpose of the following chapter is to analyse what would be the impact if some of these decisions were made differently.

It has been chosen to do a sensitivity analysis of the COP of the HP used in DH, utilisation of the full potential of excess heat from industry, and an increase in solar thermal heating in DH. Furthermore, it has been chosen to do a sensitivity analysis on a change in the electric demand in Norway. This is an area of insecurity when estimating how much of the electricity demand is moved when changing from individual electric heating to DH, and a parameter that is expected to be influenced with the introduction of EV's and electrification of the offshore oil and gas sector.

It has been chosen not to do a sensitivity analysis on the costs used in the scenarios, as this does not have an influence on the operation of the energy system in a technical simulation strategy, it will only have an influence on the total annual costs. The costs used in this master thesis are however, subject to uncertainties which are discussed further in chapter 12. If a market economic simulation strategy had been used to simulate the operation of the system, a sensitivity analysis of the costs would have been needed, as this simulation seeks to minimise the operation costs of the system.

10.1 COP of HP

The sensitivity analysis of the COP of HP used for heat production in the Reference and DH scenarios modelled in EnergyPLAN is presented in the following section. As described in chapter 7 HP's for the production of DH consist of a combination of heat pumps and electric boilers. In chapter 8 it was chosen for the Electric scenarios to increase the share of additional heat pumps, with a COP of 3, in the system, without increasing the share of electric boilers, and account for this by increasing the combined COP. However, in reality it may be that also electric boilers will be introduced in an expansion of DH or the heat pumps introduced have a higher COP.

In order to investigate the effects of introducing a larger share of electric boilers compared to heat pumps or introducing heat pumps with a higher COP, a sensitivity analysis of this parameter is done for a HP with COP of 1 and of 3.5. Here, a COP of 1 would represent a system based purely on electric boilers, while a COP of 3.5 corresponds to the COP of large scale (over 10 MW) ground water heat pumps according to NVE [2015]. These choices of COP are not necessarily realistic but are used to represent the range of COP's that may be expected for the HP in DH.

Table 10.1 shows how the different COP's are affecting the heat production from CHP, HP and boilers and these are compared with the already used COP's in the different scenarios. It was chosen to look at the changes in these three technologies as waste incineration and excess heat are assumed constant in all scenarios and would not be affected. On the left side of the table the different changes in the COP are seen along with the original results from the scenarios using the COP's that were found in table 8.4 on page 60 when designing the DH scenarios.

Table 10.1: Sensitivity analysis of HP's according to their COP and the resulting changes in the CHP, HP and boiler heat production.

	CHP [TWh/year]	**HP [TWh/year]**	**Boiler [TWh/year]**
COP 1	0.84	1.44	0.17
Reference	0.83	1.6	0.03
COP 3.5	0.8	1.66	0
COP 1	0.39	2.52	6.42
Bio 25	0.39	3.25	5.7
COP 3.5	0.38	6.76	2.18
COP 1	0.53	5.36	3.44
Electric 25	0.48	8.81	0.04
COP 3.5	0.42	8.91	0
COP 1	0.53	8.93	5.48
Electric 50	0.44	14.62	0.01
COP 3.5	0.39	14.69	0
COP 1	0.29	22.51	12.26
Electric 100	0.15	36.89	0
COP 3.5	0.08	36.95	0

From table 10.1, it can be seen that an increase in COP leads to an decreased heat production from biomass CHP and boilers in all scenarios, while the heat production from HP is increased. The decreased use of biomass CHP can be related to the higher COP decreasing both the electricity and remaining heat demand needed for DH. The production from boilers is reduced due to an increase in the thermal output capacity of HP's and EnergyPLAN prioritising using HP's over boilers. Due to the exact same reasons, a decrease in COP leads to an increase in production from biomass CHP and boilers

It was also interesting to investigate how a change in COP, affects the electricity export, production and consumption in the country, which can be seen in table 10.2.

Table 10.2: Sensitivity analysis of HP's according to their COP and the resulting changes in electricity export, production and consumption.

	Elec.export [TWh/year]	**Elec. production [TWh/year]**	**Elec. consumption [TWh/year]**
COP 1	10.51	141.24	130.73
Reference	10.75	141.23	130.48
COP 3.5	11.46	141.22	129.76
COP 1	17.04	141.07	124.03
Bio 25	17.13	141.07	123.94
COP 3.5	17.62	141.07	123.45
COP 1	14.25	141.12	126.87
Electric 25	15.82	141.1	125.28
COP 3.5	17.02	141.08	124.06
COP 1	0.19	141.12	122.65
Electric 50	21.73	141.09	119.36
COP 3.5	23.13	141.07	117.94
COP 1	20.37	141.03	120.66
Electric 100	29.79	140.98	111.19
COP 3.5	32.23	140.96	108.73

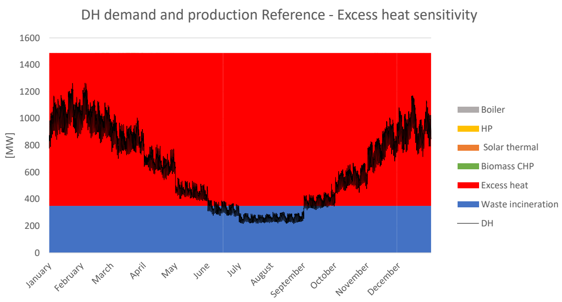
From table 10.2 it is seen that the electricity production in the country is slightly decreased with the increase of COP. This is most likely due to the CHP producing less heat, as the electricity demand for the HP's decreases when the COP is increased. The same decreasing trend is seen in the electricity consumption in the country. This is again due to the HP's needing less electricity to produce the same amount of heat for the DH system. The export of electricity, on the other hand, is increased with the increase of COP. This is related to the lower electricity demand in the country when increasing the COP and consequently the electricity demand of the HP, and hydro power production not responding to the decrease in electricity demand. Therefore, the difference between electricity production and demand is higher, and thus more electricity can be exported. Again, the exact opposite is seen when the COP is decreased - this increases the electricity demand and production in the country and decreases the exported electricity.

It may be concluded that using a larger share of heat pumps as opposed to a larger share of electric boilers for DH production would in theory enable Norway to export more electricity and free up flexible production capacity by reducing the electricity demand. This is of course the case when the technical simulation strategy of EnergyPLAN is used. If a market economic simulation of the system was done, the operation of the DH system with a large share of HP's would be much more reliant on the electricity prices and other operational costs, which would result in a different operation of the energy system.

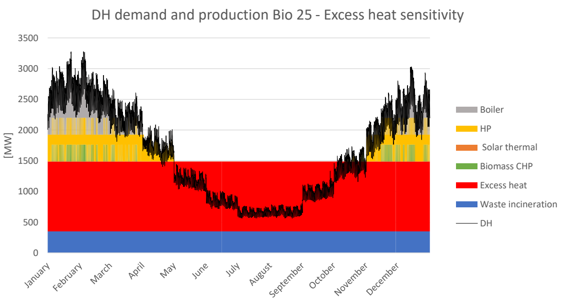
10.2 Excess heat from industry

The sensitivity of the excess heat from industry is done as the full potential of excess heat is not utilised in the DH in all of the scenarios - it is only used to cover the base load. The only scenario that utilises the full potential of excess heat in the DH production is the Electric 100, therefore this scenario has been excluded from the sensitivity analysis on the excess heat.

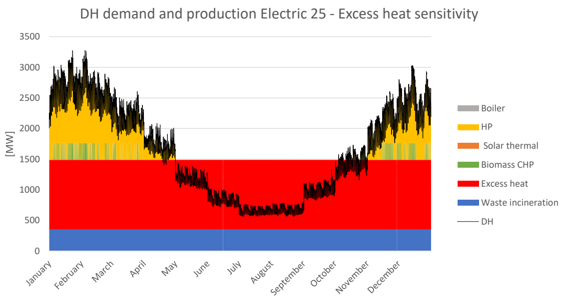
Figure 10.1 shows how the production of DH is affected if the full potential of excess heat from industry is utilised in the scenarios.



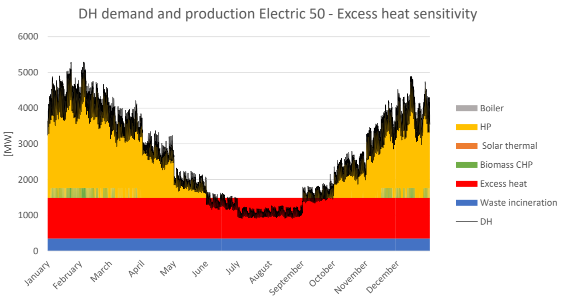
(a) Reference



(b) Bio 25



(c) Electric 25



(d) Electric 50

Figure 10.1: Sensitivity analysis on the utilisation of full potential of excess heat in the DH systems of the Reference, Bio 25, Electric 25 and 50 scenarios. Own figure.

As it can be seen in figure 10.1a in the Reference scenario, a utilisation of the full potential of industrial excess heat, heat delivered to the DH network would be higher than the DH demand in all hours of the year. However, it can also be seen that there is a potential to utilise a larger share of the potential of industrial excess heat in winter months. For summer months it can be seen that the waste incineration already covers more than the demand, so it is not possible to utilise any more heat from industrial excess heat in these months.

In the other three scenarios - Bio 25, Electric 25 and 50 scenarios the full potential of excess heat represents smaller coverage of demand as the heat demand in the scenarios is increased. The utilisation of the full potential of industrial excess heat is in all scenarios limited by it not being connected to a thermal storage option in EnergyPLAN, assuming the heat delivery is constant through the year. This leads to there being a lost potential in summer months, that with a thermal storage could potentially have been stored and used for coverage in winter months.

Furthermore, the changes that the implementation of the full potential of excess heat have on electricity production, consumption and export are shown in table 10.3.

Table 10.3: Results for sensitivity analysis for excess heat and changes in electricity export, production and consumption.

	Electricity export [TWh/year]	**Electricity production [TWh/year]**	**Electricity consumption [TWh/year]**
Reference	10.75	141.23	130.48
Reference - Full potential	11.64	140.93	129.29
Bio 25	17.13	141.07	123.94
Bio 25 - Full potential	18.23	141.07	122.84
Electric 25	15.82	141.1	125.28
Electric 25 - Full potential	18.22	141.07	122.85
Electric 50	21.73	141.09	119.36
Electric 50 - Full potential	23.39	141.07	117.68

From table 10.3 it can be seen that an increase of the excess heat from industry in DH will decrease the electricity consumption and consequently lead to a larger export of electricity.

It is important to note that if the distribution file of the excess heat was changed, then the heat production would have been different. It is also important to note that, this is the full national potential of excess heat from industry in Norway. However the DH network in Norway is not necessarily nationwide. It is therefore unclear if it is even technically possible to utilise the full potential of excess heat from industry as this would also be dependent on the industries' proximity to DH networks.

10.3 Solar thermal DH

As it was mentioned in section 8.1.4, the potential for solar thermal DH is currently investigated by the Norwegian district heating association and the Norwegian solar energy association. In the constructed DH scenarios in this master thesis it was chosen not to increase installed solar thermal DH capacity. This was partly due to difficulties sizing a fluctuating renewable resources using the simplified sizing approach that was used to design the DH scenarios. However, in the following section, it is chosen to investigate the effects of increasing the solar thermal DH capacity. For the purpose of this analysis it was chosen to multiply the production of the already existing solar thermal DH in Norway by 30, using the assumption that all current DH companies in Norway could potentially implement solar thermal DH units similar in size. A decrease in solar thermal DH is not investigated, as the existing share of solar DH is already very small.

Table 10.4 shows the heat production of the solar thermal which was used for all scenarios and is compared to the assumed increase in solar thermal.

Table 10.4: Results for yearly DH production and electricity consumption with a 30 times increase of solar thermal DH capacity.

	Solar thermal DH production [TWh/year]	**Total electricity consumption [TWh/year]**
Reference	0.04	130.48
Reference - increased solar	0.12	130.45
Bio 25	0.04	123.94
Bio 25 - increased solar	0.12	123.91
Electric 25	0.04	125.28
Electric 25 - increased solar	0.12	125.24
Electric 50	0.04	119.36
Electric 50 - increased solar	0.12	119.32
Electric 100	0.04	111.19
Electric 100 - increased solar	0.12	111.15

It can be seen from table 10.4 that a thirty time increase of the solar thermal DH capacity would still only represents a very small part of the total DH production. Furthermore, it can be seen that the electricity consumption in the country slightly decreases with the increase of solar thermal DH. It needs to be taken into consideration that this increase would require 30 times the area for solar collectors to be installed, assuming that the solar radiation is the same in all areas. It also might be, that it is not possible to install solar thermal collectors near the already established DH plants.

10.4 Electricity demand

Lastly, it is chosen to do a sensitivity analysis where the electricity demand in the country, excluding the electricity demand from DH is changed. This was found interesting due to the plans to electrify the transport and offshore oil and gas sector as described in section 2.3.1, which was not taken into account when investigating the shift from individual electric heating to DH in Norway, but was used as one of the arguments for shifting from individual electric heating to DH. It is however, chosen to include this in a sensitivity analysis to investigate the potential effects an increase in electricity demand could have on the operation of the system. Furthermore, the effect of lowering the electricity demand is investigated, in order to see the effect of potential energy efficiency and conservation measures.

Table 10.5 shows the changes in CHP, HP and boiler heat production according to a 20% increase and decrease in electricity demand.

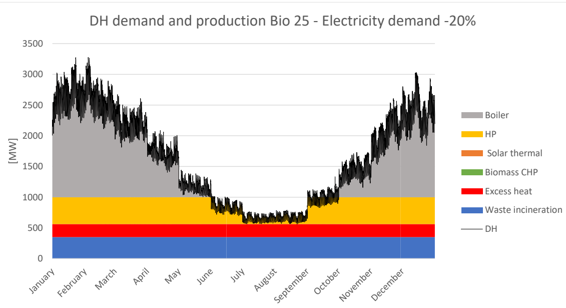
Table 10.5: Sensitivity analysis of changed electricity demand and resulting changes in the CHP, HP and boiler heat production.

	DH production CHP [TWh/year]	DH production HP [TWh/year]	DH production boiler [TWh/year]
-20%	0.09	2	0.37
Reference	0.83	1.6	0.03
+20%	1.33	1.10	0.02
-20%	0	3.25	6.09
Bio 25	0.39	3.25	5.7
+20%	1.44	3.08	4.82
-20%	0	9.08	0.25
Electric 25	0.48	8.81	0.04
+20%	1.45	7.80	0.09
-20%	0.01	15.01	0.05
Electric 50	0.44	14.62	0.01
+20%	1.14	13.90	0.03
-20%	0	37.02	0.02
Electric 100	0.15	36.89	0
+20%	0.71	36.32	0

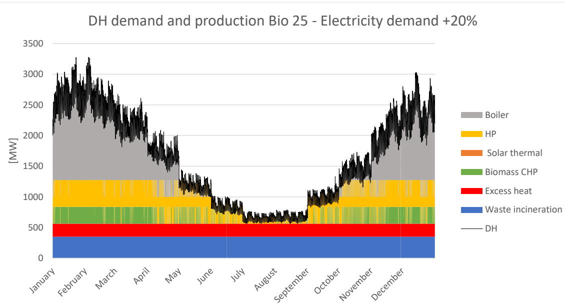
From table 10.5 it can be seen that in all scenarios, an increase in electricity demand leads to an increased production on the biomass CHP. This is a result of using the technical simulation strategy in EnergyPLAN where the CHP runs according to electricity demand first and then the heat demand. Furthermore, it can be seen that an increase of the electricity demand reduces the use of HP and boilers in all scenarios. This is partly due to the biomass CHP increasing the production of heat thereby decreasing the need for heat production on other units. It is seen that the in the Electric scenarios and the Reference scenario it is mainly the heat production of HP's that is decreased, while in the Bio 25 scenario it is mainly the production by boilers that is reduced. This is due to the boilers covering a larger share of the heat demand in the Bio 25 scenario an being used in more hours through the year. This is due to EnergyPLAN prioritising to use the boiler last, and the boilers are used more frequently in the Bio 25 scenario than in the Electric scenarios.

A decrease in electricity demand leads to the opposite effects - a decrease in production by biomass CHP and an increase in production by HP's and boilers.

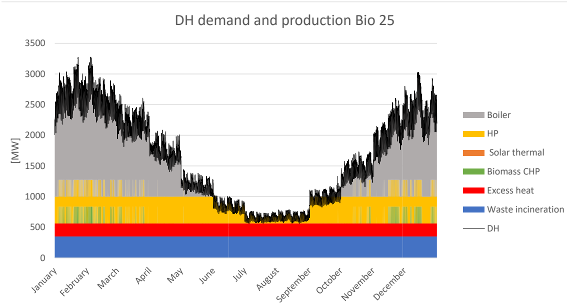
It is chosen to present the production of DH in the Bio 25 graphically to better illustrate the effect of increasing and decreasing the electricity demand. This scenario was chosen to be presented as it graphically had the most visible changes in production by the different units.



(a) -20%



(b) +20%



(c) Bio 25

Figure 10.2: Sensitivity analysis on the utilisation of full potential of excess heat in the DH systems of the Reference, Bio 25, Electric 25 and 50 scenarios. Own figure.

From figure collection 10.2 it becomes very apparent that the biomass CHP operates in more hours of the year when the electricity demand is increased. Consequently, this reduces the use of boilers as the HP production capacity is utilised before the boilers. It is seen that a decrease in electricity demand minimises eliminates the use of the biomass CHP.

Table 10.6 shows how the electricity export, production and consumption in the country is affected by a change in the electricity demand. In the table it is seen that an increase of electricity consumption leads to a decrease in electricity export. Only in the Electric 100 scenario does an increase in electricity demand not lead to import of electricity in the system, however, the amount of export is significantly decreased. A decrease of electricity demand leads to a need for import of electricity, which is denoted as negative export in the table. In the Electric 100 scenario this decrease of electricity demand leads to CEEP, which is indicated with * in the table. This is an indication that the energy system is not able to respond to the change in demand within the country, and additional transmission line capacity is needed.

In general, it is seen in all scenarios, that the electricity producing units do not respond to a change in electricity demand, as the production remains relatively unchanged. From the electricity producing units in the system, only the biomass CHP responds to the changes in electricity consumption. Even though it would be expected that the dammed hydro power would respond to the changes in the electricity consumption, it does not, and the yearly production is constant in all scenarios. It is believed that this is due to the dammed hydro power being limited not only by the hydro power production capacity but also by the dammed hydro storage content, and how this is modelled in EnergyPLAN. This is discussed further in chapter 12.

Table 10.6: Sensitivity analysis of changed electricity demand and resulting changes in electricity export, production and consumption.

	Elec.export [TWh/year]	**Elec. production [TWh/year]**	**Elec. consumption [TWh/year]**
-20%	35.99	140.96	104.97
Reference	10.75	141.23	130.48
+20%	-14.49	141.41	155.9
-20%	41.24	140.93	99.69
Bio 25	17.13	141.07	123.94
+20%	-6.6	141.45	148.05
-20%	39.78	140.93	101.15
Electric 25	15.82	141.1	125.28
+20%	-7.64	141.46	149.1
-20%	44.11	140.93	96.82
Electric 50	21.73	141.09	119.36
+20%	-0.43	141.34	141.77
-20%*	49.27	140.92	91.65
Electric 100	29.79	140.98	111.19
+20%	10.62	141.19	130.57

10.5 Summary

It can be concluded from the sensitivity analysis in the previous, that all scenarios are sensitive to changes in the heat production in the DH system. A change in COP of the HP in DH will affect the electricity consumption in the energy system and consequently the production of electricity from biomass CHP. In turn, this affects the heat production from biomass CHP which results in a increased or decreased utilisation of HP's.

Furthermore, it was seen that an increase of industrial excess heat in DH would decrease the need of alternative production technologies in winter months. However, due to a lack of thermal storage connected to excess heat from industry, there would be a loss of heat in summer months.

It was also investigated how a 30 time increase in solar thermal production capacity would affect the DH production. It was found that the changes were insignificant as the share of solar DH would still be small compared to other production units.

Lastly, it was investigated how a ±20% change in the electricity demand, excluding demand from DH, would affect the operation of the DH system and consequently the energy system in Norway. It was seen that a change in electricity demand had a large effect on the production of electricity and heat from the biomass CHP. This reduced the DH production from other units. Furthermore, it was clearly seen in this analysis that all electricity producing units except the biomass CHP did not respond to the change in total electricity demand in the country. This was also seen in all other sensitivity analyses, and will be discussed further in chapter 12.

11 Barriers

The main research question on page 13 included a question regarding the potential barriers for a shift from individual electric heating to district heating.

The purpose of the following chapter is to identify some potential barriers in a potential change from individual electric heating to DH. Taking departure in the theory of technological change presented in section 4.4, a technological change entails a change in either technique, organisation, profit, product or knowledge, and may include changes in several of them. In this section the change from individual heating to DH was identified as a difficult radical change, as radical changes can be identified in several of the 5 elements, and most prominently in terms of organisation and product. When there is a radical change in these elements, there is also the potential for barriers to the change being present. The following section therefore namely focuses on potential barriers within these two elements of technological change.

11.1 Barriers in organisation

Organisational barriers can be related to required changes in legal framework and support schemes that come with a change from individual electric heating to DH. A presentation of the relevant support schemes legal framework concerning DH in Norway was given in section 6.4. Based on this, there are several potential barriers that can be identified, explained in the following subsections.

11.1.1 Policy changes for district heating

In april 2016, the Norwegian government presented a white paper on Norwegian energy policy towards 2030. The key message in the white paper was that security of supply, climate and business development needs to be seen in each others context in order to secure an efficient and climate friendly energy supply towards 2030. [Regjeringen, 2016b]

In this white paper, it is alluded that the current distribution of responsibility between NVE as licensing authority and municipalities as planning authorities is sometimes subject to inadequate coordination when it comes to decision making. The municipalities are described as key players in the facilitation of district heating infrastructure in Norway, as it is closely related to other municipal planning responsibilities and is a part of the local infrastructure. [Det Kongelige Olje- og Energidepartement, 2016]

It is therefore proposed to remove the current national licensing scheme for district heating in the energy act, as this will clarify the municipality's important role in the development of district heating. It is stated that this would require necessary changes in the energy act as well as the plan and building act, but it is not further specified what these necessary changes are. Finally, it is stated the the Government will also reconsider the need for the current regulations regarding mandatory connection to district heating. [Det Kongelige Olje- og Energidepartement, 2016]

The statements regarding the removal of the national licensing scheme for district heating was met by criticism from the Norwegian district heating association, Norsk Fjernvarme. The criticism was mainly directed towards the lack of specification of how the transfer from of power from state to municipality is to happen, as the white paper does not outline any specific rule changes or new tools and resources for municipalities to use. It is argued that the current licensing scheme secures a streamlined development of district heating with less local bureaucracy. Norsk Fjernvarme states that they think that the white paper signals that the decision is not well enough thought through, not legally, economically or market wise.

The suggestion to change the licensing scheme comes in addition to the changes in the national building regulatory (TEK10) as described in section 6.4.2, where there are no longer specific requirements to have building in licensed DH areas to be built with water borne heating systems. This further adds to the concern of Norsk Fjernvarme who sees a tendency that national building regulations overrule municipal decisions to use otherwise lost heat for district heating purposes.

If looking to Denmark, there is, opposite Norway, a long tradition of regulation and planning of district heating through municipal organs. In Denmark 64% of all residential households have DH, so a change from national planning to municipal planning does not necessarily in itself pose a barrier for the expansion of DH[Dansk Fjernvarme, 2015]. However, a lack of guidelines and rules regarding DH may serve as a barrier when moving from national planning to local planning.

11.1.2 Lack of support schemes for DH customers

As described in section 6.4, there are existing national support schemes in place for developers of DH production and networks. However, there are currently no national support schemes for customers wanting to connect to DH. This may prove to be a barrier if the financial burden for potential customers who wish to connect to DH is too large, preventing them from connecting to DH, and thereby limiting the potential customer group for DH in Norway. The potential financial burden for customers as a barrier is further analysed under the identification of barriers in the product element of technological change.

11.2 Barriers in technique

A change from individual electric heating to DH in itself entails a change in technique in terms of the technique used for heating. Furthermore, it entails a change in how heating is produced and delivered - from on site small scale production to off site large scale production. In the following subsections, potential barriers resulting from the radical change in heating technique are identified.

11.2.1 Heat density

The change from on site heat production to off site heat production will necessarily entail a need for a heat distribution network delivering heat to customers. Norway is a vast country with a relatively small population compared to it's geographical size, as described in section 6.2.4. This could potentially be a barrier to the expansion of DH in Norway because of a lower linear heat density, which describes the ratio between the heat delivered and the length of the DH piping and network [IEA ETSAP, 2013]. A higher linear heat density increases the cost effectiveness of a DH system, while a low one, reduces it [IEA ETSAP, 2013]. A higher number of users connected per network length is assumed to give a higher linear heat density, but also a higher consumption per user connected per network length is assumed to increase the linear heat density. Even though Norway is a vast country, 81% of the Norwegian population live in cities or villages, where the population density and the building density is larger, as was also described in section 6.1 [SSB, N.D.]. So in these densely populated areas, the heat density may not serve as a barrier for DH. However, this is only relevant for 81% of the population. In the scenario Electric 100, where 100% of the individual heating is shifted to DH, the linear heat density may serve as a barrier, if the 19% of the population that do not live in cities or villages all have individual electric heating, as DH may not be a feasible alternative for these.

Furthermore, the Norwegian residential sector is highly made up of individual houses and not apartment complexes. Out of 2 476 519 residencies in Norway in 2016, 69% were detached, semi-detached and town houses [SSB, N.D.]. This could have an effect on the linear heat density, if it is assumed that an apartment complex has a significantly higher heat demand than one single detached/semi-detached building.

11.2.2 Lack of infrastructure in existing buildings

One of the largest potential barriers of an expansion of the DH system in Norway, is the current infrastructure of the Norwegian buildings. This master thesis has investigated the effect of shifting from individual electric heating to DH. However, it has not been taken into account that a large share of the buildings in Norway do not necessarily already have waterborne heating systems. When investigating the main heating sources used in residential buildings in section 2.3.2, it was found that the main heating sources in residential buildings were electrical panel heaters and air-to-air heat pumps which are airborne heating systems. Potentially, 16% of residential households have main heating sources that could indicate that they have waterborne heating systems installed - central heating, oil boilers, heat recovery geothermal HP and DH [SSB, N.D.]. It may be expected that service sector and industry building have a larger share of waterborne heating systems installed, mainly because of their size. In a report by [Norges Naturvernforbund, 2003] from 2003, it was estimated that 65% of all service sector buildings had waterborne heating systems. For buildings without waterborne systems, it may be assumed that a shift to DH would also require an installation of a waterborne heating system in the building.

The need for installing a waterborne heating system may prove to be a barrier for the shift from electric heating to DH, as it represents an extra investment cost. This master thesis does not seek to do a full analysis on the costs/savings for individual buildings with a change from individual electric heating to DH, but some of the investment costs are discussed in the following. Investment costs in waterborne heating systems were by Ericson et al. [2016] given to be 500 NOK/m^2. However, it is assumed that this is without any additional renovation costs that may be needed in relation to the installation. For a building of 200 m^2, the installation costs of a waterborne heating system thereby amounts to 100 000 NOK in one-time investment costs. In comparison, Ericson et al. [2016] estimates the investment costs of electric heating systems to be 450 NOK/m^2 over a 50 year period. The total investment costs in electric heating is therefore not much lower than the installation of a waterborne system. However, it must be assumed that the investment costs for electric heating units is spread over the 50 years, as the units cannot be expected to have a life time of 50 years. Thereby, the one time investment costs for electric heating units are expected to be lower. The high investment cost in waterborne heating systems for buildings may serve as a barrier for a shift from individual electric heating to DH, as consumers are unwilling or unable to pay high one time investment costs for the system. Furthermore, if the DH price continues to follow the electricity price, only an increased efficiency by changing from air borne heating to waterborne heating will give customers an economical incentive to change to DH. It may be more relevant for new buildings, or in relation to larger renovations of buildings, to install water borne heating systems. However, for these there is no longer a requirement to have waterborne heating systems if they are of a size less than 1 000 m^2 according to the building requirements, as described in section 6.4.

11.3 Summary

The identified potential barriers are mainly found on the demand side of DH for potential consumers. More specifically, the barriers are mainly related to the lack of existing infrastructure for DH in buildings. A change in policies regarding DH as well as a change in the building requirements, can prove to be a barrier as there is no longer the same requirement to prepare buildings for renewable heating and consequently the instalment of waterborne heating systems. There may also be a barrier in regards to the heat density of the DH system due to Norwegian housing mainly consisting of detached houses as well as 19% of the population living in areas outside towns and cities. The lack of waterborne heating systems in existing buildings may prove to be a barrier for an expansion of DH, unless there are economical incentives for the customer, such as heat savings and support schemes, as the one time investment cost of waterborne heating systems is high.

Discussion 12

Following the results of the technical simulation of the Norwegian energy system in the Reference scenario and the four different DH scenarios, some of the relevant areas of difficulty and methodological choices in this master thesis will be discussed in the following.

12.1 Choice of modelling software

In this master thesis, a technical simulation of the Norwegian energy system, balancing both heat and electricity demands, using the modelling tool EnergyPLAN, was carried out. EnergyPLAN was chosen as the modelling tool because of option to simulate the system on an hourly basis and its free availability.

It has not been possible to use EnergyPLAN's market economic simulation for the simulation of the Norwegian energy system. This is due to the tool being constructed based on the Danish energy system, and not being able to handle the introduction of a large share of hydro power capacity for electricity production. It is however expected that a market economic simulation would give other results for the simulation of the Norwegian energy system, and show other effects for how the shift from individual electric heating to district heating will affect the operation of the system. The potential effect of doing a market economic simulation of the Norwegian energy system will be discussed later on in this chapter.

In hindsight, a different modelling tool could have been chosen for a market economic simulation of the Norwegian energy system. Several modelling tools were investigated in section 5.3. Here, different criteria for the modelling tool were defined, where only EnergyPLAN and Mesap PlaNet were able to simulate the Norwegian energy system on an hourly basis. EnergyPLAN was chosen over the other due to its free availability. It was considered important for the project to simulate the system on an hourly basis, as it was found interesting to investigate the operation of the system and the relation between heat and electricity production on an hourly basis. A simulation of the system only on a yearly basis would for example not be able to show the relation between interconnection capacity and free production capacity within the country.

12.2 Lack of demand response of dammed hydro power in EnergyPLAN

It was concluded in chapters 9 and 10 that the dammed hydro power did not respond to changes in electricity demand from changes in the energy system. It is believed that this is due to how the dammed hydro is modelled in EnergyPLAN. By default, the dammed hydro storage is half full at the beginning and the end of the simulation year, and it needs to be drained to make room for the natural inflow to the reservoirs. Due to this, the production is kept constant in months where the storage needs to be drained, and consequently does not reduce its production, even though the electricity consumption within the country is reduced. The same is true for increased electricity demands - the dammed hydro power production remains the same, as the storage content is taken into account. This leads to a higher export. This indicates that the dammed hydro power production is more dependent on the natural inflow to the system than on the electricity demand.

It is however expected, that in reality the dammed hydro is to a certain extent able to regulate its production up and down according to the electricity demand. Naturally, the dammed hydro power is dependent on the storage content, but not necessarily in the same way it is modelled in EnergyPLAN. The storage is also not necessarily half full in the beginning and end of every year, as this depends on both the natural inflow in the specific year and on the electricity demand throughout the year.

This creates a problem when investigating the flexibility of the Norwegian energy system in this master thesis. Partly because the freed up capacity cannot be utilised to increase production and partly because the lack of response of the dammed hydro will give misinformation related to the actual export.

12.3 Market economic simulation of the Norwegian energy system

As already mentioned in section 12.1, a market economic simulation of the Norwegian energy system is expected to give different results regarding the operation of the system, and consequently different conclusions to the effects of changing from individual electric heating.

As described in section 5.3.1, the technical simulation of the energy system seeks to minimise the use of fossil fuels in the system and minimising import. As the Norwegian electricity and heating system is mainly based on renewable electricity production from dammed hydro power, the effects of shifting from individual electric heating to DH therefore has minimal effects on the operation of the energy system in a technical simulation.

However, in reality, it is expected that the Norwegian energy system is not strictly operated as in the technical simulation. The willingness to invest in increased interconnection capacity to Europe is assumed to be due to economical interests, as simulations have shown that there is not necessarily a need to import electricity to cover Norway's own demand because of the high production capacity of hydro power facilities and low penetration of fluctuating renewables. However, in reality, Norway is part of the Nordpool power market where production of electricity is bid in on the market and the price is set matching production and demand. The production and exchange of electricity is therefore dependent on the market economical conditions. Furthermore, it is expected that an increase in interconnection capacity is done because it is a profitable investment. This might be done as an increase of interconnection capacity is expected to even out electricity prices between bottleneck areas, and thereby can contribute to increasing the Norwegian electricity prices. It also could be able to utilise more electricity at very low prices through importing cheap electricity from Europe when there is excess production from fluctuating renewables.

It is expected that the market economic simulation would, for example, have an effect on the operation of the HP's and thermal storage in DH as well as the production of electricity, by utilising hours with low electricity prices to produce heat on HP's. The effect on the energy system operation of changing from individual to collective heating is therefore expected to be more apparent in a market economic simulation of the system, as the collective system gives a larger flexibility in moving demand when large scale heat storages are implemented in the system.

12.4 Shifting from fossil fuels to DH

This master thesis only investigates the effects of changing from individual electric heating to DH. However, it may be more relevant to change from individual fossil fuel based heating, for example oil boilers and natural gas boilers, to DH, as this could have a larger effect on decreasing the CO_2-emissions and increasing the RES share. It is however uncertain if this would have a different effect on the operation of the Norwegian energy system, if using the same production units as done in the DH scenarios. It is expected that a change from fossil fuel based individual heating to electricity based DH would entail an increase in total electricity demand within the country, however, it is not certain that the operation of the DH production units will change.

12.5 Lack of data for heating system

One of largest challenges in this master thesis has been the lack of historical data for the Norwegian heating sector. The lack of data is largely due to the construction of the Norwegian heat market, with large shares of individual electric heating that can not be measured. The input data for the Norwegian heating sector are used in the model of the Norwegian energy system, and is therefore largely based on estimations found in different reports as well as interpretation of national statistics. The data inputs regarding the heating sector are therefore subject to considerable uncertainties. For example, the estimations for the total Norwegian heating market varied between 45-65 TWh, which is a difference of 31% between the highest and the lowest estimation. A lack of data for the Norwegian heating sector has made it necessary to construct heat demand profiles which may not be an accurate representation of the reality. In the construction of these profiles, it has not been taken into account how the heat demand profile varies between the residential, service and industry sector. If data for these sectors were available, this would have also had an effect on the heat demand profiles, electricity demand profiles in the DH scenarios and subsequently on the results from all scenarios constructed in this master thesis.

12.6 Insecurities in cost data

Another insecurity element in both the Reference scenario and the DH scenarios are the costs used for investments. The prices vary according to technology, and it has not always been possible to separate between the different technologies within a category in EnergyPLAN. Furthermore, it has not always been possible to find prices for the specific types of units in the same source. Therefore, it has been prioritised to use the same source for all investment prices instead of using different sources. For technologies where prices have not been available in the source, prices for a similar technology have been used. For example prices for electric heaters that are not boilers, were not included in NVE [2015], and instead, costs for electric boilers have been used. These were used as it must be assumed that all households that have electric heating as their main heat source also need electric boilers for the production of hot water. This is chosen, as it is considered that using the same source would be better when comparing the prices of the different units with each other. Using for example a Danish source for some of the technologies and a Norwegian source for others could create difficulties in comparing the different unit prices with each other as installation costs and the cost of man power may be different in the two countries.

A Danish source was used for the calculation of the costs of expanding the DH network in Norway and the substations needed for an expansion of the network, as general cost data were not available from NVE [2015] which was used for other cost data in this master thesis. It may be that the costs used for the expansion of the DH network are too low compared to actual prices in Norway. It may be expected that these costs are higher in Norway due to higher labour costs as well as more difficult geological conditions. Furthermore, as described in chapter 10 it was chosen not to do a sensitivity analysis on the costs for the different scenarios as it would change only the total annual costs of the energy systems and not the operation of the energy systems.

12.7 Sizing of thermal storage

Thermal storage capacity was included in all scenarios and sized to minimise the heat production from boilers. However, this sizing approach is not necessarily the correct one. In reality, the sizing of the storage will also be based on economical considerations. The specific operation of the storage in the DH scenarios was not analysed further in this master thesis. However, the operation of the storage in the Reference scenario was discussed on page 48 as there was an imbalance between the DH production and demand here. It was seen that the thermal storage was only used in some periods of the year, and most of the year the storage content was constant. Questions could therefore be raised whether or not it is worth investing in thermal storage capacity. The thermal storage operation may have been different in a market economic simulation where it could be expected that the thermal storage would also be used to utilise hours with low electricity prices to produce heat from electricity to be used in hours with higher electricity prices. This is however not investigated further in this master thesis.

Another problem related to the sizing of the thermal storage is that the sizing that is done in this master thesis is on a national level. In reality, there would not be only one large nationwide thermal storage, but several storages that may not be sized and operated in the same manner as the thermal storage is in this master thesis.

12.8 Case study as alternative to national energy system analysis

In this master thesis it was chosen to answer the research question based on a national energy system analysis. An alternative approach could have been to use a case study. A case study according to Abercrombie et al. [1984,p.34] is able to help a more detailed and complex investigation of, for example, a single DH plant in Norway. However, the problem with using a case study is that one cannot necessarily draw general conclusions from the case study. This does not necessarily mean, that it can not provide an insight of the general research field and serve as an example case. [Abercrombie et al., 1984,p.34] For the purpose of this master thesis it was chosen to do an analysis on the national Norwegian energy system as a case study would not necessarily reflect the effects on the operation of the national energy system. It is expected that the local DH companies would operate according to their DH customers' demands and seek to fulfil these at the lowest possible cost. However, on a national scale it important to look at the interaction between the electricity and heating sector.

13 Conclusion

The aim of this master thesis was to investigate the effects on the operation of the Norwegian energy system when shifting from individual electric heating to DH and identify potential barriers for such a shift.

In order to assess the effects a shift from individual electric heating to DH would have on the operation of the Norwegian energy system, a Reference scenario describing the current Norwegian energy system was created. Using this as a basis, the following scenarios representing a shift from individual electric heating to DH were designed:

- Bio 25
- Electric 25
- Electric 50
- Electric 100

Where 25%, 50% and 100% of the individual heating demand was shifted in the respective scenarios. The Bio 25 scenario was based on the DH production units in the Reference scenario and the addition of excess heat from industry and biomass boilers. The Electric scenarios were based on the DH production units in the Reference system with an addition of excess heat from industry and heat pumps.

The operation of all scenarios was simulated using a technical simulation strategy balancing both heat and electricity demands in the modelling tool EnergyPLAN. The results from all scenarios were then analysed and compared in chapter 9.

From the analysis of the operation of the DH scenarios compared to the Reference scenario, it was concluded that a shift from individual electric heating to DH would in all scenarios have an effect on the total electricity demand in the Norwegian energy system. In the Bio 25 scenario this was due to the shift from using electricity for heating to using biomass for heating. In the Electric scenarios this was due to a shift to more efficient electric heating units.

The shift from individual electric heating to DH did, however, not have a significant effect on the electricity production in the Norwegian energy system. In all scenarios a decrease in the total electricity demand of the energy system lead to an increase in export. In section 4.3 it was defined that an increase in export could be a sign of inflexibility in the energy system. This was confirmed in the sensitivity analysis in chapter 10. Here it was concluded that the dammed hydro power was not able to respond to the decrease in electricity demand in the DH scenarios, due to the production from hydro power being limited not only by the hydro power capacity, but also by the storage content. In chapter 12 it was concluded that this inflexibility in the dammed hydro power production is not due to the shift from individual electric heating to DH, but to the way the dammed hydro power is modelled in EnergyPLAN.

Barriers to the shift from individual electric heating to DH were identified both in relation to the organisational aspects the shift would entail and in the change of technique used for heating. Organisational barriers were found in a potential lack of guidelines and rules if a suggested change of the current national DH licensing scheme is moved to municipal level. In addition, a lack of requirement to prepare new buildings for renewable heating and an instalment of waterborne heating systems in the building requirements could serve as a barrier for the shift, as buildings are not prepared for DH. The main barrier to a shift from individual electric heating to DH is identified to be this lack of waterborne heating systems in the current Norwegian building mass. A change from individual electric heating would entail a large one time investment cost for potential customers, which could prevent them from choosing DH for heating. This is hindered further by a lack of support schemes for DH customers.

Two sub-questions were created to support the main research question. The first sub-question was related to how different DH technologies would affect the operation of the energy system. This was investigated both through the design of DH scenarios based mainly on either biomass or electricity and further analysed in the sensitivity analysis in chapter 10. In general, it can be concluded that all DH production units that do not use electricity as fuel will result in a decrease in the total electricity demand in the country.

The second sub-question was related to the effect a shift from individual electric heating to DH would have on the flexibility of the Norwegian energy system and the interaction with the European energy system. This sub-question was related to the idea of Norway functioning as a virtual green battery for Europe. In section 4.3 it was found that an increase in the number of hours where the difference between flexible electricity production capacity and electricity consumption was equal to or larger than the interconnection capacity, would indicate a better interaction with the European energy system and increase the possibility of using Norway as a virtual green battery of Europe. In all DH scenarios the electricity demand was decreased, and consequently the difference between electricity demand and flexible production capacity was increased. It was concluded that in all hours of the year, it would be possible to utilise the full export capacity, and therefore a shift from individual electric heating to DH would contribute positively to the idea of Norway being a virtual green battery for the European energy system.

13.1 Future work

The conclusions in this master thesis have been limited by the choice of modelling software and the simulation strategies. This was partly due to the simulation tool EnergyPLAN not being able to simulate the Norwegian energy system and furthermore, due to the modelling choices behind EnergyPLAN.

For example, it is not expected that the Norwegian energy system operates according to the technical simulation strategy in EnergyPLAN. A market economic simulation could have shown other effects of changing from individual electric heating to DH, but as was discussed in chapter 12 EnergyPLAN was not able to do a market economic simulation for the operation of the Norwegian energy system. This is however something that is interesting to investigate further, as it may be expected that operation of DH system where operational costs are minimised may reflect better the effect of a shift to DH.

As was concluded in the previous, the dammed hydro power did not respond to a change in the electricity demand as could be expected in the real energy system. A further analysis, potentially using a different simulation software is therefore needed to be able to better investigate the flexibility of the Norwegian energy system.

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Appendix A

The following sections describe the inputs to the EnergyPLAN Reference scenario. All inputs are summarised in tables.

A.1 Demand

In this section, all inputs from the "demand" tab in the EnergyPLAN model are described. This includes electricity, heating, transport, fuel consumption in industry and etc.

A.1.1 Electricity

The total electricity demand for Norway in 2015 was 129.012 TWh. Figure A.1 shows the distribution file used for the yearly electricity demand which is based on data collected from Nordpool [N.D.].

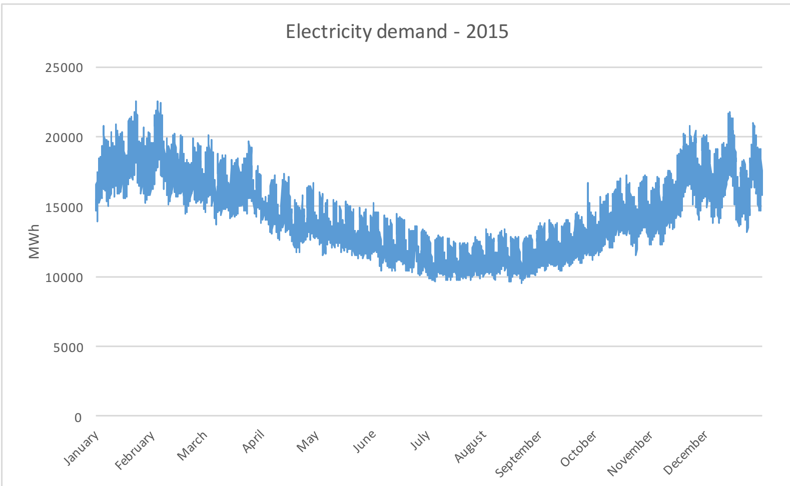

Figure A.1: Electricity demand in 2015 based on historical market data from Nordpool [N.D.].

From the figure it can be seen that the electricity demand is higher in winter months, which is strongly related to the widespread use of electricity as the main heating source. The highest hourly electricity consumption in 2015 was recorded in February while the lowest was found in August. The average load for 2015 was 14 687 MWh.

The electric heating demand is calculated as 63% of a total heat demand of 50 TWh, as described in section 6.2.

The electric cooling demand is, as described in section 6.2 assumed to be the same as the total cooling demand, subtracting district cooling.

Table A.1 summarises the inputs used in the electricity demand tab in the EnergyPLAN model.

Table A.1: Inputs in the electricity demand tab in the EnergyPLAN model.

Electricity demand	**[TWh/year]**
Fixed demand	129.012
Heating	31.1
Cooling	1.1
Biomass conversion	-
Transportation	0.27

A.1.2 Heating

The heat demand in EnergyPLAN is split up into individual heating and district heating. In addition, there is the possibility to define the heat demand per building for EnergyPLAN to calculate the correct number of units needed to cover individual heat demands.

Individual heating

The individual heating covers all heating that is not covered by district heating, in all sectors.

As described in section 6.2 it is difficult to estimate the heat demand in Norway as the heating sector is highly electrified.

Data from SSB [N.D.] have been used to find the individual heat demand in the residential and service sector based on the use of coal, oil, biomass and gas. Here it is assumed that all use of these fuels are for heating purposes, and therefore the input in the individual heating demand tab in EnergyPLAN is the fuel consumption of these in service sector and residential households.

For the industrial sector, it is difficult to estimate what is the share of fuels used for heating and what is used for other purposes. However, in order to design a district heating system it is needed to know which fuel use can be replaced by district heating, and this therefore needs to be separated and put in the individual heating demand tab.

It needs to be taken into account that the numbers for coal, oil, gas and biomass may not be accurate for a specific year, as these are fuels that are storable and may therefore not be used in the same year as they are sold.

As EnergyPLAN does not specify what type of individual heat pump is used, the electric efficiency (COP) is calculated based on NVE [2016b] where it is specified that individual heat pumps produced 15 TWh of heat in 2015 and for this used 6.5 TWh electricity. This gives a resulting COP of 2.3 which is consistent with a large share of heat pumps being air-to-air which have a lower COP. The installed capacity of heat pumps divided on the different heat pump technologies can be seen in figure A.2.

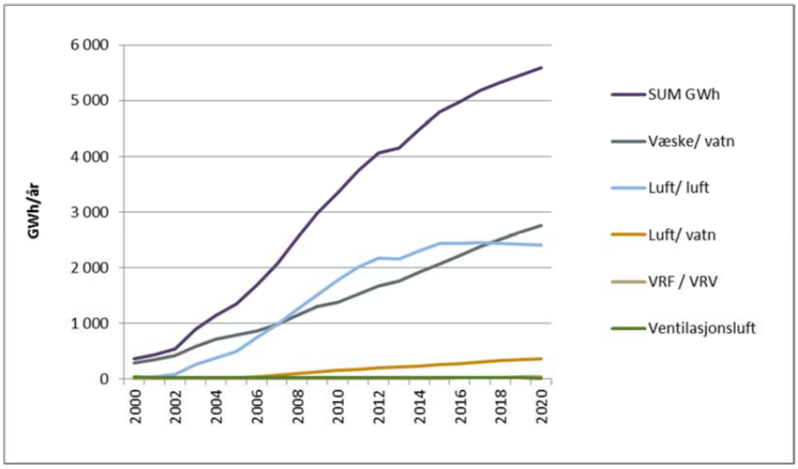

Figure A.2: Installed capacity of different heat pump types in Norway.

In the figure, it can be seen that the largest share of heat pumps installed is air-to-air heat pumps. The following shares have been found using the program ScanIt to read the graph.

- Air-to-air - 50%
- Fluid-to-water - 42%
- Air-to-water - 5%
- Ventilation - 1.5%
- VRF/VRV - 1.5%

For the fluid-to-water heat pumps, it is not specified what is the external heat source, and it is therefore not differed between heat pumps using ground water, sea water, ground heat etc.

It is assumed that the electric use of heat pumps is included in the total electric heat demand, and individual HP's are therefore subtracted from the electric heat demand.

One of the problems by having limited information regarding the Norwegian heat demand is the lack of information regarding the distribution of the heat demand during the year. As described in section 6.2 the REMODECE project provided a daily distribution of the heat demand for residential households, but not for other sectors. A yearly profile for the delivery of district heating for a service sector building in Trondheim was also provided by Statkraft, however, it is not known what type of service sector building this is. It is therefore still unknown how the general hourly distribution for service sector buildings is. Furthermore, the hourly distribution of heat demand in industry is unknown.

It is assumed, as described in section 6.2, that the yearly heat market amounts to 50 TWh, and that the share of total yearly electricity demand used for heating is 31%. It is not, however, known how the hourly heat demand share is distributed. It seems reasonable to assume, that the share of heat demand compared to the electricity demand on an hourly basis, would be larger in winter and smaller in summer, as the space heating demand is temperature dependent. There is however also a part of the heat demand that is not temperature dependent - the hot water demand and possibly some of the heat demand in the industrial sector which is used for industrial processes.

A heat demand profile on an hourly basis is made based on the hourly electricity consumption profile and then weighted according to degree days on a monthly basis. Another profile is made assuming 76.6% of the heat demand is temperature dependent and 23.4% is not temperature dependent. This is consistent with the relation between the space heating and hot water demand in the REMODECE project described in section 6.2. The resulting distributions for 2015 can be seen in figure A.3.

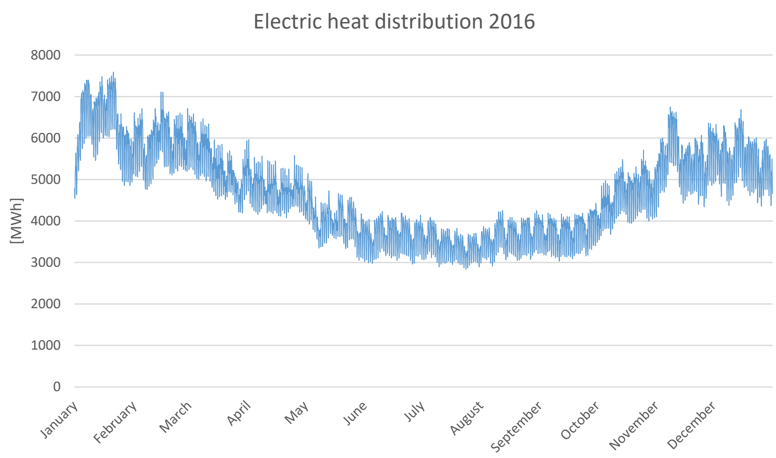

Figure A.3: Temperature distributed heat demand 2015.

From figure A.3 it can be seen that the weighting of the heat demand according to the degree days affects the maximum difference in hourly load through the year. The larger share of distribution that is weighted according to degree days, the larger the maximum difference. The maximum difference in demand through the year for the three lines are listed in the following:

- Constant - 4 030.93
- 76% weighted - 7 993.7
- Entire demand weighted - 9 204.3

One of the problems by estimating a heat demand profile is that information regarding maximum peak load may be lost in the data manipulation process. Using monthly temperature data may also cause additional inaccuracies regarding the maximum peak load, as the daily temperature variations are lost. However, the heat demand profiles created are still assumed to show a general tendency for the heat demand through the year.

Furthermore, using the electricity demand profile to create a general heat demand distribution profile may be inaccurate as the electricity profile may have other factors than only the heat demand affecting the distribution through the year. An example could be that an industry shut down would affect the electricity demand profile.

In the Reference scenario, it is chosen to use the demand profile where 76% of the heat demand is weighted with degree days, as this still shows a certain variation in load through the year, but still takes into account that part of the demand is constant through the year.

The distribution profile in the figure is for the distribution of electric heating, but is in this master thesis also used for the distribution of other individual heating and district heating.

The inputs for the individual heat demand in the heating demand tab are seen summarised in table A.2.

Table A.2: Inputs for the individual heat demand in the heat demand tab in the EnergyPLAN model.

Indv. heating	**Fuel input [TWh/year]**	**Efficiency [%]**	**Heat demand [TWh/year]**	**Electric efficiency [%]**	**Capacity limit [-]**
Coal	1.81	80	1.45	-	-
Oil	4.89	92	4.50	-	-
Ngas	3	100	3	-	-
Biomass	7.23	83	6.00	-	-
Heat pump	-	-	15	2.3 (COP)	1
El. heating	-	-	24.6	-	1

For the biomass used for for individual heating, it needs to be pointed out that this is not necessarily used in biomass boilers. According to Dovre [2012] 15-20% of the residential heating is from wood fireplaces which do not produce hot water for example. However, for the purpose of this report these are referred to as individual biomass boilers.

Furthermore, electrical heating in residential households is divided into heating units for the production of hot water and heating units for space heating. The heating units for hot water are necessarily connected to a hot water tank or a water borne system, while the electric heating for space heating in many residential houses is often air borne systems. Therefore, there are two different types of technologies used for electric heating in households, and their characteristics are not necessarily the same. However, for the purpose of this master thesis, it is assumed that the electric heat demand for buildings is fairly equal both for water borne and air borne electrical heating systems, and it is therefore chosen only to operate with one type of electrical heating: electrical boilers. However, one should bear in mind when designing a national district heating system, that not all residential households have water borne heating systems, and this may serve as a barrier for the connection to district heating.

Solar thermal heating

The individual share of solar thermal was found based on the following:

$$\text{Solar share} = \frac{\text{Total area solar/Avg installed area per house}}{\text{Total number of houses}} \tag{A.1}$$

Using data from [Solenergiforening, N.D.] and [Norsk Fjernvarme, N.D.a] as inputs. This resulted in a share of 0.16%. EnergyPLAN differs between solar thermal units according to the heat source in the house. Therefore, the share needs to be split between houses with boilers, electric heating and etc. For the purpose of the Reference scenario, it was assumed that the share of solar thermal was the same for all households, no matter the main heating source, as it was not possible to find data to distribute the shares unevenly.

The total output from solar thermal production in individual heating is calculated to be 0.013 TWh. The input of solar heating is distributed by weighting the input in solar thermal according to the different technologies' share of heat demand compared to the total heat demand in the individual sector. The heat storage is assumed to be 1 day.

For the solar thermal, it is assumed that the distribution profile for the solar radiation will be the same as in Denmark, and a distribution profile for Denmark is therefore used. The chosen distribution file is a standard file for individual solar thermal created for EnergyPLAN and downloaded from the EnergyPLAN website. The total production from solar thermal is expected to be lower in Norway than in Denmark, as Norway lies further north and does not fall within the same radiation "zone" as Denmark. The distribution file does not affect the total radiation through the year, only the distribution of it.

District heating

The total gross production of DH in 2015 was 5.444 TWh [SSB, N.D.]. If compared to the net production of DH delivered to consumers, the network losses are calculated to be 11%. The district heating production in Norway in 2015 is placed into group 2 in EnergyPLAN. For group 2, it is assumed that all CHP plants are decentralised plants used for DH production and they produce both heat and electricity. All other production units that are placed in group 2 are assumed to be heat-only boilers, as it is not specified whether biomass and other fossil fuels are used in CHP plants. Heat pumps, solar thermal, waste heat, etc. are also placed in group 2.

Table A.3: Inputs for the district heating demand in the heat demand tab in the EnergyPLAN model.

DH group	Production [TWh/year]	Network losses [%]	Heat demand [TWh/year]
Group 1	0	0	0
Group 2	5.444	11	4.83
Group 3	0	0	0

A.1.3 Heat demand per building

The heat demand per building is used to calculate the cost per unit for individual heating. Individual buildings consist of residential buildings, service sector buildings and industrial buildings not connected to district heating networks. The average heat demand per building is found using the calculation shown in equation A.2.

$$\text{Heat demand per building} = \frac{\text{Total yearly heat demand}}{\text{Number of buildings in Norway}} \tag{A.2}$$

The number of buildings in Norway is found to be 2 715 178, excluding garages in January 2017 SSB [N.D.], and the total heat demand is, as described in section 6.2, 50 TWh. This results in a heat demand per building of 18 415 kWh/year.

A.1.4 Cooling

According to SSB [N.D.] the district cooling production in 2015 was 169 GWh. The district cooling was in 2011 produced by compression and absorption chilling, free cooling and heat pumps [Juhler, 2013]. It is assumed that these units are under district heating group 2 in EnergyPLAN as all heat pumps are also in the same group. The COP for the electric cooling is 1, which is the minimum requirement in the TEK10 as described in section 6.2. The COP for district cooling is 2.4 [Norconsult, 2010]. The inputs in the cooling tab are seen in table A.4.

Table A.4: Inputs for the cooling demand in the cooling demand tab in the EnergyPLAN model.

Cooling	**Electricity consumption [TWh/year]**	**Heat consumption [TWh/year]**	**COP [-]**	**Cooling demand [TWh/year]**
Electric	1	-	1	1.0
Group 1	-	0	-	0
Group 2	-	0.07	2.4	0.17
Group 3	-	0	-	0

A.1.5 Industry and other fuel consumption

For the fuel consumption in industry and other fuel consumption, 2015 data from SSB [N.D.] was used and consumptions were distributed according to the categories "industry" and "various". The fuel losses are accounted for under the "various" tab. These inputs in the EnergyPLAN model can be seen in table A.5.

Table A.5: Inputs for the industry and other fuel use in the industry and other fuel consumption demand tab in the EnergyPLAN model.

Fuel	Industry [TWh/year]	Various [TWh/year]	Fuel losses [TWh/year]
Coal	10	4.51	0
Oil	8.23	206.15	0
Ngas	11.992	71.71	0
Biomass	1.96	0	0

A.1.6 Transport

The fuels used in transport are based on 2015 statistical numbers from SSB [N.D.].

For the electric vehicles in the Norwegian energy system, it is assumed that all vehicles are dump charge vehicles as it is assumed smart charge and V2G vehicles are not implemented in 2016. The total yearly electricity consumption for electric vehicles is calculated based on the following factors:

- Number of EV's [SSB, N.D.] - 102 917
- Average driving length per vehicle [SSB, N.D.] - 13 246 km
- Average electricity consumption per km [Norsk Elbilforening, 2012] - 0.2 kWh/km

Through multiplying these, a total yearly consumption for electric vehicles is found. In the calculation, it is not differed between different types of vehicles, as 95% of the vehicles are cars. For the calculations, the average electricity consumption is therefore a standard estimation for cars given by Norsk Elbilforening [2012].

In July 2016 there were only 23 hydrogen cars, and it is chosen not to include this as they will have a minimal effect on the system [Skogstad, 2016].

The inputs for the fuel consumption in transport can be seen in A.6.

Table A.6: Inputs for the transport fuel use in the transport demand tab in the EnergyPLAN model.

Fuel	Fossil [TWh/year]	Biofuel [TWh/year]	Waste [TWh/year]	Electrofuel [TWh/year]	Total [TWh/year]
JP	10.73	0	-	0	10.73
Diesel	38.54	1.70	0.00	0	40.24
Petrol	10.16	0	-	0	10.16
Ngas	1.50	-	-	-	1.50
LPG	0.03	-	-	- 0.03	
H_2	-	-	-	-	0
El. dump charge	-	-	-	-	0.273
El. smart charge	-	-	-	-	0

A.2 Supply

The following section describes and summarises the inputs in the supply tab in EnergyPLAN for the Reference scenario.

A.2.1 Heat and electricity

There are three combined power plants in Norway based on natural gas or LNG: Kårstø, Mongstad and Melkøya. Per 2016 Kårstø is closed, with Mongstad planning to close production in 2018. Melkøya delivers energy offshore to the Snøhvit field, and is therefore not accounted for in the onshore electricity production. [Rosvold and Vinjar, 2016] The result is therefore, that there at the moment is one natural gas fired CHP with an installed electric capacity of 280 MW and a thermal capacity of 350 MJ/s [Statoil, 2005]. However, for the purpose of this master thesis it was chosen not to include this CHP due its recent decommission. Furthermore, in 2009 there was an installed electric capacity of 100 MW biomass based CHP [Norsk Energi, 2011]. This is placed also in district heating group 2. The efficiencies used for the biomass CHP is from NVE [2015]

It is assumed there are no industrial CHP's. All inputs for the CHP's in the heat and electricity supply tab can be seen in table A.7.

Table A.7: Inputs for the fuel distribution in the fuel supply tab in the EnergyPLAN model.

CHP	**Group 2**	**Group 3**
CHP condensing mode operation		
Electric capacity (PP1) [MW-e]	-	-
Electric efficiency [%]	-	-
CHP back pressure mode operation		
Electric capacity [MW-e]	100	0
Thermal capacity [MJ/s]	275	0
Electric efficiency [%]	24	0
Thermal efficiency [%]	66	0

Boiler capacity

For district heating boilers, only the fuel input or the production output is given, while the capacity of the boilers are unknown. The capacity of the different boilers are found using equation A.3.

$$\text{Installed capacity} = \frac{\text{Yearly fuel input} \cdot \text{Efficiency}}{\text{Yearly full load hours}} \tag{A.3}$$

Efficiencies and full load hours are taken from NVE [2015]. The capacity input is therefore only an estimate, as the boilers do not necessarily operate with the same amount of full load hours as estimated in the NVE [2015]. A summary of the calculations can be seen in table A.8. For the biomass boiler, there are different boilers depending on the type of biomass used. It is chosen to use average specifications for wood chip boilers, as almost 50% of the DH-production from biomass is based on wood chips [Norsk Fjernvarme, N.D.a].

Table A.8: Boiler production and capacity.

Boiler type	Fuel input [GWh]	Efficiency [%]	Production [GWh]	Full load hours [h]	Capacity [MW]
Oil	87.1	92	80.132	2 500	32.05
Ngas	205.8	92	189.336	2500	75.7
Biomass	1 914.8	87	1 665.9	3 225	516.6
Electric	-	98	784	2500	313.6

In lack of proper overviews over technologies used for district heating production, it is difficult to estimate what DH-production is produced on biofuel boilers and what share is produced in biofuel CHP. For the purpose of this master thesis, it is assumed that the biomass used for DH production is used in boilers and that the 100 MW of CHP that are found in group 2, per 2016 is producing heat for their own processes, not to the district heating network. However, it is also assumed that these CHP's could possibly be used in the DH system in the future.

A.2.2 Electricity only

Hydro power

The hydro power capacity in Norway consists of both dammed hydro power and run-of-river hydro power. The total hydro power capacity is taken from SSB [N.D.] for 2015 and is 31 372 MW. Out of these, 1 352 MW are run-of-river hydro according to ENTSO-E.

The hydro storage capacity in Norway was 82 224 GWh in March 2016 [NVE].

Table A.9: Overview of pumped hydro facilities in Norway including pump back capacity.

Hydro power plant	Pump back capacity [MW]	Source
Saurdal	640 MW	[Svarstad, 2017]
Aurland	270 MW	[Vereide et al., 2017]
Duge	200	[Vereide et al., 2017]
Nygard	56	[Vereide et al., 2017]
Øljusjøen	50	[Vereide et al., 2017]
Tevla	50	[Vereide et al., 2017]
Jukla	40	[Vereide et al., 2017]
Herva	33	[Vereide et al., 2017]
Brattingfoss	11	[Vereide et al., 2017]

Total	**1350**

The production of hydro power plants depend not only on the demand for electricity but also on the water inflow to the reservoir. In years with a larger inflow, the added energy to the reservoirs will be larger and therefore the potential energy for production will be larger.

While dammed hydro is highly controllable, river hydro is not as controllable and depends on the natural river flow. [Hafslund]

For the modelling of dammed and river hydro in EnergyPLAN, data for the water inflow is needed. For dammed hydro, data from NVE for the natural inflow at 82 stations were used. These data are used to describe the natural inflow to the Norwegian hydro power system [NVE, 2016a]. The data used as input in the EnergyPLAN model is from 2015. The natural inflow is given as daily data for the 82 different points, which is then added together and compared to the total energy inflow that year. As EnergyPLAN needs hourly data the daily profile is divided in to 24 equal inputs to get a distribution file on an hourly basis. According to e-mail correspondence with Loe [2017], the hydro power production will not depend on the hourly inflow, and creating an hourly distribution that does not vary through the day is therefore deemed sufficient for the model input. The resulting hourly profile for 2015 can be seen in figure A.4 below.

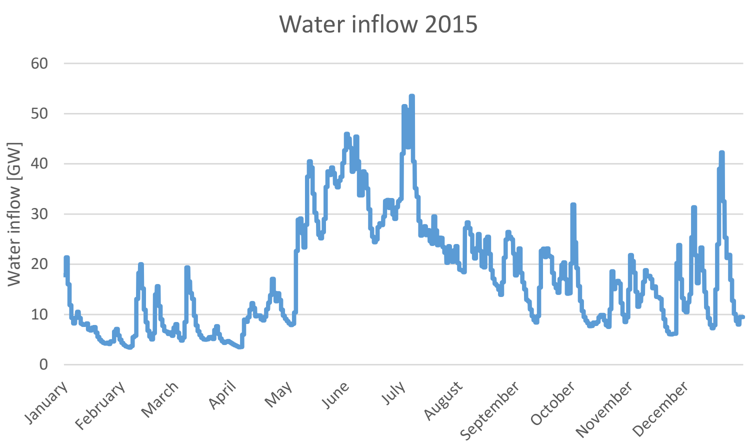

Figure A.4: Distribution of natural inflow to Norwegian hydro power reservoirs in 2015. Based on data collected from NVE.

Intermittent renewable electricity

Three types of intermittent renewable electricity are included in the Reference scenario: wind power, PV and river hydro.

For the wind power, the capacity in 2015 was 867 MW [SSB, N.D.]. It is known that the production from wind turbines in 2015 was 2.12 TWh. It has not been possible to find an hourly distribution of the wind production in Norway, therefore, the hourly wind production distribution profile is based on the wind production in western Denmark in 2015. This was chosen as the wind turbines in Norway are mainly located on the west coast of Norway, and it is assumed that the meteorological conditions on the west coast of Denmark are similar to the west coast of Norway. This was chosen over the Swedish production, as most wind turbines in Norway are located in coastal areas, and not inland. In order to achieve the correct production, a correction factor of -0.53 was used, resulting in an estimated capacity factor of 0.28.

According to Solenergiforening [N.D.] the grid connected installed capacity of PV in Norway was 13.6 MWp in 2016. These produced approximately 0.01 TWh of electricity. As for the solar thermal, the distribution file available in EnergyPLAN was used for the distribution of production. No correction factor was added. The estimated capacity factor is 0.08.

River hydro capacity was, as described under the dammed hydro power supply, 1 352 MW. For the distribution file for the river hydro, data for the flow of river Nidelva at the measuring point at Rathe is used. This data was provided by Statkraft [Loe, 2017]. This flow does not necessarily represent the flow in all rivers in Norway. It is however assumed to be a valid input, since EnergyPLAN does not use the absolute numbers in the distribution file, only the profile through the year. Without adding a correction factor, this results in an estimated production of 4.88 TWh and a capacity factor of 0.41.

The input data for the electricity only supply tab can be seen in table A.10 and A.11.

Table A.10: Inputs for central power plants in the electricity only supply tab in the EnergyPLAN model.

Central Power Plant	**Capacity [MW-e]**	**Efficiency [%]**	**Annual production [TWh/year]**
PP1	-	-	n/a
Dammed hydro water supply	-	-	148.41
Dammed hydro power	30 020	90	133.57
Dammed hydro power storage	**Storage capacity [GWh]**	**Pump back capacity [MW-e]**	**Pump back efficiency[%]**
	82 224	1350	90

Table A.11: Intermittent renewable electricity in the electricity only supply tab in the EnergyPLAN model.

Technology	**Capacity [MW]**	**Stabilisation share [%]**	**Estimated production [TWh/year]**	**Correction factor [-]**	**Post corr. production [TWh/year]**	**Est.cap. factor [-]**
Wind	867	0	2.63	-0.53	2.12	0.28
PV	13.6	0	0.01	0	0.01	0.08

River hydro	1 352	0	4.88	0	4.88	0.41

A.2.3 Heat only

Five inputs are included in the heat only tab: solar thermal, compression HP, geothermal from absorption HP and industrial excess heat. They are all inputs, which are connected to the district heating groups.

Solar thermal collectors are included in the DH group 2. According to [Norsk Fjernvarme, N.D.a] the total DH production from solar thermal collectors in 2015 was 4 GWh. The storage and losses were calculated. This resulted with 0.07 GWh storage and 5% losses of the storage tank. The share of district heating demand with solar thermal is 0.07%.

As EnergyPLAN does not have the option to include electric boilers, except for CEEP regulation and to decrease export, it is chosen to treat electrical boilers as heat pumps with a COP of 1. A total electric capacity and an average COP for the heat pumps and the electric boilers is therefore needed. According to SSB [N.D.] the production of district heat coming from electric boilers and heat pumps in 2015 was 673.1 GWh and 542.8 GWh, respectively. All heat pumps in district heating are treated as compression heat pumps, as it is assumed that there are no geothermal absorption heat pumps. The combined capacity and COP of the HP's and electric boilers are calculated using the following assumptions [NVE, 2015]:

- **Heat pump**
  COP: 3
  Number of full load hours: 3200

- **Electric boilers**
  COP: 1
  Number of full load hours: 2500

Based on the DH production and the assumptions above, the capacities and average COP is calculated using equations A.4 and A.5 respectively.

$$\text{Capacity} = \frac{\text{Production}}{\text{COP}} / \text{Number of full load hours} \tag{A.4}$$

$$\text{Average COP} = \text{HP share of total capacity} \cdot \text{COP HP} + \text{El. share of total capacity} \cdot \text{COP El} \tag{A.5}$$

In this tab, the industrial excess heat is also accounted for, which is 181.1 GWh [SSB, N.D.]. The distribution file used is a constant as it is assumed that .The inputs for the heat only tab can be seen in figure A.12.

Table A.12: Inputs for the heat only in the supply tab in the EnergyPLAN model.

Heat only	**Group 1**	**Group 2**	**Group 3**	**Unit**
Solar Thermal				
Production	0	0.004	0	[TWh/year]
Storage	0	0.07	0	[GWh]
Loss	0	0.05	0	[% share]
Share	0	0.0007	0	[% share]
Result	0	0	0	[TWh/year]
Compression Heat Pump				
Electric capacity	-	325.78	0	[MW-e]
COP	-	1.34	0	[-]
Thermal capacity	-	437	0	[MJ/s]
Geothermal from Absorption HP	0	0	0	[TWh/year]
Industrial Excess Heat	0	0.181	0	[TWh/year]

A.2.4 Fuel distribution

The fuel distribution tab defines how the fuels are distributed on the different technologies. Table A.13 summarises the different fuel inputs. The input for natural gas in CHP2 is taken from Statoil [2005] while the remaining are from SSB [N.D.].

Table A.13: Inputs for the fuel distribution in the fuel supply tab in the EnergyPLAN model.

Fuel	**Coal [TWh/year]**	**Oil [TWh/year]**	**Ngas [TWh/year]**	**Biomass [TWh/year]**
DHP	0	0	0	0
CHP2	0	0	7.62	0
CHP3	0	0	0	0
Boiler2	0	0.0871	0.2058	1.9148
Boiler3	0	0	0	0
PP1	0	0	0	0
PP2	0	0	0	0

A.2.5 Waste

The waste incineration plants in Norway are accounted for in the waste tab under the supply tab in EnergyPLAN.

According to SSB [N.D.] 4.8568 TWh of waste was used in the district heating sector in 2015, out of a total licensed plant capacity of 5.2724 TWh [Ulvang, 2017]. It is assumed the waste is all used in decentralised incineration plants and placed in DH group 2.

Data on all waste incineration plants was provided by Ulvang [2017] in Avfall Norge. From these data it was found that the total heat produced from the plants was 3.07 TWh/year and electricity produced was 0.35 TWh/year. It is not specified for which year this is from.

The thermal and electrical efficiency of the waste incineration plants was found through testing numbers in EnergyPLAN until the production matched what was given by Ulvang [2017]. All input data in the waste supply tab can be seen in table A.14.

Table A.14: Inputs for the waste incineration in the waste supply tab in the EnergyPLAN model.

Unit	**Waste input [TWh/year]**	**DH efficiency [%]**	**DH prod. [TWh/year]**	**Electric efficiency [%]**	**Electricity prod. [TWh/year]**
Group 1	0	0.8	0	0	0
Group 2	4.8568	0.633	3.07	0.073	0.35
Group 3	0	0	0	0	0
Total	4.86	-	3.07	-	0.35

A.2.6 Liquid gas and fuels

It is chosen not to take liquid gas fuel plans into account because of a lack of data.

A.2.7 CO_2

The CO_2 content in the fuels used in the Reference scenario are taken from Energistyrelsen [2015] and given in table A.15.

Table A.15: Inputs for the waste incineration in the waste supply tab in the EnergyPLAN model.

Fuel type	**CO_2 content**	**Unit**
Coal	93.95	[kg/GJ]
Fuel oil / Diesel / Petrol / JP	73.58	[kg/GJ]
Ngas	56.95	[kg/GJ]
LPG	63.1	[kg/GJ]
Waste	36.79	[kg/GJ]

It is chosen not to take carbon capture and storage (CCS) into account as there are currently no CCS facilities onshore in Norway.

A.3 Balancing and storage

A.3.1 Electricity

Electric grid stabilisation requirements are not included in the Reference scenario. This is chosen as dammed hydro power plants are required to be able to ramp up and down within 30 seconds for grid stabilisation purposes [Statnett, 2012] and that there are no large power plants in the system that can not change the production quickly.

There is no electricity storage included in the model as there are no known electricity storage units in the Norwegian energy system.

The CEEP regulation strategy chosen is to first replace the CHP in gr. 2 with boiler and then reducing RES1 and RES2 which is wind and PV. It is however, not expected that the CEEP regulation strategy is needed in the simulation of the Norwegian energy system, as the share of fluctuating renewables and CHP is very low compared to the controllable dammed hydro power and the relatively high electricity load in the Norwegian energy system. Furthermore, the river hydro is not included in the CEEP regulation as it cannot necessarily be regulated due to potential problems with flooding.

A.3.2 Thermal

It has not been possible to find data regarding the size of the thermal storage capacity in the Norwegian energy system. Due to a lack of data, it has therefore been chosen to size the storage to minimise the production of DH on boilers and increase the production of DH on HP's, resulting with a thermal storage capacity of 1 GWh that is optimised for 14 days, indicating that this is relatively small scale storage units and not seasonal storage units.

A.3.3 Liquid gas and fuels

It is chosen not to include liquid gas and fuels storage in the model of the Reference scenario.

A.4 Cost

All cost inputs used for the Reference scenario are described and summarised in the following sections.

A.4.1 General

In the general tab, under cost, the CO_2 price which is included in the marginal cost of electricity in Norway is taken into account. It is 60 NOK/t CO_2 according to NVE [2015]. A 4% interest rate is chosen based on NVE [2015]. This is an interest rate recommended for socio-economic calculations, and the project specific interest for business economic calculations may vary. However, as this master thesis does not concern a specific project, but rather looks at the overall energy system, it is difficult to estimate a general business economic interest rate as this depends on the specific investors. Furthermore, the interesting factor in this master thesis is not the interest rate itself, but rather the difference between the technologies.

A.4.2 Investment and fixed O&M

All investment prices, life times and O&M costs are taken from NVE [2015]. EnergyPLAN does not differ between unit sizes, even though there will be price differences per installed unit depending on the size of the unit/plant. In general, a larger size per unit equals a lower specific investment cost and O&M. As it has not been possible to find overviews over every installed unit in the country, average or median costs based on the costs found in NVE [2015] are used. These may be higher or lower than the costs of the real life system. Furthermore, EnergyPLAN does not separate between different types of CHP plants and boilers, e.g. natural gas, biomass, oil and etc. For the inputs of the CHP plants, costs for biomass plants are used, as there are only biomass CHP plants included in the model. For boilers, the costs are weighted according to the share of units in the system, where biomass boilers has the main share. All costs that are used in the EnergyPLAN model can be found listed in table A.16. All costs are taken from NVE.

Table A.16: Investment and fixed O&M costs

Technology	**Unit**	**Investment [MNOK/Unit]**	**Period [Years]**	**O&M [% of inv.]**
Heat & Electricity				
Small CHP units	[MW-e]	10	25	2.6
Heat storage CHP	[GWh]	61.1	20	0
Waste CHP	[TWh/year]	4 689	20	2.8
Heat pump gr 2	[MW-e]	1.14	20	0.3
Boilers gr 2+3	[MW-th]	5.7	20	8.9
Renewable energy				
Wind	[MW-e]	10.25	20	0.77
Photo voltaic	[MW-e]	15	25	2
River of hydro	[MW-e]	8.8	40	1.5
Hydro power	[MW-e]	8.8	40	1.5
Hydro pump	[MW-e]	1.31	40	1.5
Industrial excess heat	[TWh/year]	30	-	-
Heat infrastructure				
Indv. boilers	[1000-Units]	0.063	20	13.9
Indv. HP	[1000-Units]	0.063	15	0.2
Indv. Electric heat	[1000-Units]	0.018	20	13
Indv. Solar thermal	[1000-Units]	49.9	25	0

Additional investments cost were included in the Reference scenario in regards to the DH network and substations. This is seen in table A.17.

Table A.17: Additional investment and O&M costs.

Description of investment	Period [Years]	O&M [% of inv.]	Total inv. cost [MNOK]
DH Network	40	0.1	3906.59
DH Substation	20	8.5	265.44

Additional investment costs for the DH network in the DH scenarios modelled in this master thesis are calculated according to the DH demand in the system and the additional DH substation costs according to the peak demand in the system.

A.4.3 Fuel

The fuel tab consists of prices, handling costs and taxes on fuels and taxes on electricity. The fuel prices used in the EnergyPLAN model are taken from Connolly [2015] as these are world market prices that are needed as an input for the model. The handling costs used in the model are also the costs presented in the Connolly [2015] taken from the Danish Energy Agency. They were deemed to be suitable for this master thesis as it is assumed that the Danish handling costs are similar to the Norwegian ones. The fuel and fuel handling costs used in the Reference scenario are seen in table A.18.

Table A.18: Fuel price.

	Coal	Fuel oil	Diesel /Gasoil	Petrol /JP	Ngas	Biomass
Fuel price	28.48	85.74	151.83	160.76	72.88	62.6
Fuel handling costs						
Central CHP and power stations	0.6	2.04	-	-	3.83	10.39
Dec. CHP, DH and industry	-	17.14	-	-	10.43	10.03
Individual households	-	-	26.01	-	26.37	54.78
Transport (road and train)	-	-	28.29	38.12	-	102.97
Transport (air)	-	-	-	6.23	-	-
Taxes						
Individual households	-	-	132.31	-	22.77	-
Industry	-	77.46	-	-	22.77	-
Boilers	-	77.46	-	-	22.77	-
CHP units	-	77.46	-	-	22.77	-

The taxes used in the model are obtained from Skattedirektoratet [2017]. There are different taxes on the import or production of mineral products in Norway. All the taxes are for sulphur free fuels or fuels containing less that 0.05% sulphur per weight unit. For sulphur containing fuels, there is an additional sulphur tax which is 0.136 NOK/liter per started 0.25% weight unit sulphur. It is unknown what the sulphur content in the fuels input to EnergyPLAN is, and it is therefore chosen not to include the sulphur tax in the model. This will, however, in a real system need to be included, where the fuels are differed according to their sulphur content. Mineral products used in transportation are subject to an additional road use tax. This tax is not included in the EnergyPLAN model, as these are not included separately in EnergyPLAN. There are certain exemptions from some of the taxes on mineral products. These include:

- No CO_2 tax on planes and ships in international traffic
- No CO_2-, sulphur- and base tax on biodiesel
- No CO_2 tax on exported fuels

For the purpose of this master thesis, it is assumed that the taxes for import/production of mineral products are reflected in the use of these products in all sectors. The taxes are therefore converted into cost per GJ using heating values and used as input in EnergyPLAN. Mineral products used in transportation are subject to an additional road use tax. This tax is not included in the EnergyPLAN model, as it is not possible to input this separately in the model. All fuel taxes are seen listed in table A.18

In addition to taxes on mineral products, there are also taxes on electricity used. The tax is 0.16 NOK/kWh for households and 0.0048 NOK/kWh for industry, mining, DH production, data centres and employment training providers [Energi Norge, 2016]. The following are exempted from the electricity tax:

- Growth industry
- Chemical reduction or electrolysis
- Metallurgical or mineralogical processes
- Energy recovery facilities
- Micro power plants

The table A.19 outlines the electricity taxes for energy conversion in DH systems and individual households.

Table A.19: Taxes on electricity for energy conversion.

NOK/MWh	**DH systems**	**Individual houses**
Electric heating	0.0048	0.16
Heat Pumps	0.0048	0.16
Electrolysers	0.0048	0.16
Electric cars	-	0.16
Pump storage	0.0048	-

A.4.4 Variable O&M

The variable O&M costs used are from NVE [2015] and can be seen in table A.20.

Table A.20: Variable O&M.

	Cost	Unit
DH and CHP systems		
Boiler	11	NOK/MWh-th
CHP	30	NOK/MWh-e
Heat Pump	12	NOK/MWh-e
Electric heating	1	NOK/MWh-e
Individual		
Boiler	15	NOK/MWh-th
CHP	0	NOK/MWh-e
Heat Pump	2	NOK/MWh-e
Electric heating	1	NOK/MWh-e

A.4.5 External electricity market

The Norwegian electricity spot prices values for 2015 are gathered from Energinet.dk [2015] and are presented in the figure A.5 below. The average price for 2015 was 177.38 NOK per MWh; the highest price was recorded in November and the lowest in July with 624.09 NOK/MWh and 9.23 NOK/MWh respectively.

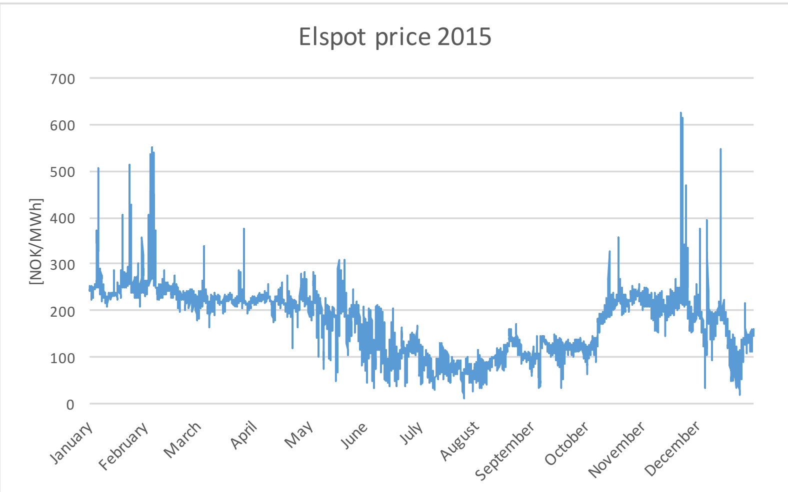

Figure A.5: Electricity spot prices of Norway in 2015. Based on data collected from Energinet.dk [2015]

The addition factor used in the model is 0 and the multiplication factor is 1. The addition and multiplication factor may be used to manipulate the electricity prices.

Furthermore, the transmission line capacity is set to 8895 MW as this is already planned capacity for 2021. For the purpose of this master thesis the transmission line capacity was chosen not to be changed from the Reference to the DH scenarios as this was needed to secure comparability between the scenarios.

B EnergyPLAN results

In the following the results from all of the modelled scenarios in EnergyPLAN are seen in the following order:

- Reference scenario
- Bio 25 scenario
- Electric 25 scenario
- Electric 50 scenario
- Electric 100 scenario

Input Reference scenario.txt

The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	96,91	Fixed imp/exp.	0,00
Electric heating + HP	31,12	Transportation	0,27
Electric cooling	1,00	Total	129,31

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	5,44	0,00	5,44
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	5,44	0,00	5,44

Wind	867	MW	2,12	TWh/year	0,00	Grid
Photo Voltaic	14	MW	0,01	TWh/year	0,00	stabili-
Wave Power	0	MW	0	TWh/year	0,00	sation
River Hydro	0	MW	4,88	TWh/year	0,00	share
Hydro Power	30020	MW	133,57	TWh/year		
Geothermal/Nuclear	0	MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	100	275	0,24	0,66	
Heat Pump	326	437			1,34
Boiler		624		0,83	
Group 3:					
CHP	0	0	0,36	0,45	
Heat Pump	0	0			3,00
Boiler		0		0,83	
Condensing	0		0,45		

Heatstorage: gr.2: 1 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 0,0 Per cent gr.3: 0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,35
Gr.3:	0,00	0,00

Regulation Strategy:	Technical regulation no. 2	
CEEP regulation	210000000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	1,00	
Maximum import/export	8895	MW

DistEnerginet_no_NOKprices_2015.txt

Addition factor	0,00	NOK/MWh
Multiplication factor	1,00	
Dependency factor	0,00	NOK/MWh pr. MW
Average Market Price	177	NOK/MWh
Gas Storage	0	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0,80	
Hydro Turbine:	0		0,90	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:	0,000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	59,43	1,50	0,00
Household	1,81	4,89	3,00	7,23
Industry	10,00	8,23	11,99	1,96
Various	4,51	206,15	71,71	0,00

Output

	District Heating										Electricity																		Exchange	
	Demand	Production									Consumption						Production							Balance					Payment	
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba- lance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec- trolyser MW	EH MW	Hydro Pump MW	Tur- bine MW	RES MW	Hy- dro MW	Geo- thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab- Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Imp Million NOK	Exp Million NOK
January	1028	0	371	0	247	388	0	22	0	0	12470	31	1505	0	4584	0	0	976	17509	0	40	90	0	100	0	25	0	25	0	4
February	1010	0	371	0	248	374	0	17	0	0	12261	31	1474	0	4507	0	0	786	17378	0	40	90	0	100	0	21	0	21	0	3
March	848	0	371	0	187	291	0	0	0	-1	11719	31	1220	0	3783	0	0	690	16062	0	40	68	0	100	0	107	0	107	0	16
April	670	0	371	0	27	271	0	0	0	0	10622	31	995	0	2988	0	0	753	14736	0	40	10	0	100	0	902	0	902	0	138
May	460	0	371	0	1	89	0	0	0	0	10702	31	611	0	2055	0	0	689	14291	0	40	0	0	100	0	1622	0	1622	0	214
June	331	0	371	0	0	1	0	0	0	-41	10467	31	393	0	1477	0	0	1296	13699	0	40	0	0	100	0	2668	0	2668	0	216
July	257	0	371	0	0	0	0	0	0	-114	9830	31	304	0	1145	0	0	887	13465	0	40	0	0	100	0	3083	0	3083	0	177
August	264	0	371	0	0	0	0	0	0	-107	10108	31	312	0	1177	0	0	604	13682	0	40	0	0	100	0	2698	0	2698	0	205
September	388	0	371	0	0	25	0	0	0	-8	10365	31	478	0	1733	0	0	589	14042	0	40	0	0	100	0	2064	0	2064	0	167
October	556	0	371	0	44	141	0	0	0	0	11209	31	762	0	2478	0	0	656	14741	0	40	16	0	100	0	972	0	972	0	125
November	800	0	371	0	177	252	0	0	0	0	11985	31	1133	0	3567	0	0	740	16188	0	40	65	0	100	0	316	0	316	0	44
December	935	0	371	0	208	353	0	3	0	0	12054	31	1368	0	4167	0	0	924	16748	0	40	76	0	100	0	167	0	167	0	12
Average	628	0	371	0	95	182	0	3	0	-23	11147	31	878	0	2800	0	0	799	15206	0	40	34	0	100	0	1224	0	1224	Average price	
Maximum	1264	1	371	0	275	437	0	182	0	71	15381	61	1825	0	5655	0	0	2058	21792	0	40	100	0	100	0	4230	0	4230	(NOK/MWh)	
Minimum	217	0	371	0	0	0	0	0	0	-153	8303	0	257	0	968	0	0	232	12817	0	40	0	0	100	0	0	0	0	-	123
TWh/year	5,51	0,00	3,26	0,00	0,83	1,60	0,00	0,03	0,00	-0,20	97,91	0,27	7,71	0,00	24,59	0,00	0,00	7,02	133,57	0,00	0,35	0,30	0,00		0,00	10,75	0,00	10,75	0	1322

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon- version	Electro- Fuel	Wind	PV	Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	-	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	1,81	14,51	16,32	0,00	16,32	5,52	5,52
Oil	-	-	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	59,43	4,89	214,38	278,70	0,00	278,70	73,83	73,83
N.Gas	-	1,26	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	1,53	3,00	83,70	89,50	0,00	89,50	18,35	18,35
Biomass	-	-	-	0,03	-	0,00	-	-	4,86	-	-	-	-	-	-	-	-	-	7,23	1,96	14,08	0,00	14,08	0,64	0,64
Renewable	-	-	-	-	-	-	-	133,57	-	-	-	-	2,12	0,01	-	-	0,01	-	-	-	140,60	0,00	140,60	0,00	0,00
H2 etc.	-	0,00	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-1,70	-	-	-	-	-	-	1,70	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	1,26	-	0,04	-	0,00	-	133,57	4,86	-	-1,70	-	2,12	0,01	-	-	0,01	62,66	16,92	314,56	539,20	-23,90	515,30	98,34	98,34

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Output specifications Reference scenario.txt The EnergyPLAN model 12.4

District Heating Production

Gr.1 and Gr.2

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	0	0	0	0	1028	0	371	247	388	0	22	0	349	0
February	0	0	0	0	1010	0	371	248	374	0	17	0	308	0
March	0	0	0	0	848	0	371	187	291	0	0	0	398	-1
April	0	0	0	0	670	0	371	27	271	0	0	0	488	0
May	0	0	0	0	460	0	371	1	89	0	0	0	496	0
June	0	0	0	0	331	0	371	0	1	0	0	0	496	-41
July	0	0	0	0	257	0	371	0	0	0	0	0	496	-114
August	0	0	0	0	264	0	371	0	0	0	0	0	496	-107
September	0	0	0	0	388	0	371	0	25	0	0	0	496	-8
October	0	0	0	0	556	0	371	44	141	0	0	0	496	0
November	0	0	0	0	800	0	371	177	252	0	0	0	499	0
December	0	0	0	0	935	0	371	208	353	0	3	0	496	0
Average	0	0	0	0	628	0	371	95	182	0	3	0	460	-23
Maximum	0	0	0	0	1264	1	371	275	437	0	182	0	1000	71
Minimum	0	0	0	0	217	0	371	0	0	0	0	0	0	-153
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	5,51	0,00	3,26	0,83	1,60	0,00	0,03	0,00		-0,20

Gr.3

	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Stor-age MW	Ba-lance MW
January	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0	0
Maximum	0	0	0	0	0	0	0	0	0	0
Minimum	0	0	0	0	0	0	0	0	0	0
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00

RES specification

	RES1 Wind MW	RES2 Photo \ MW	RES3 Wave I MW	RES 4-7 er MW	Total MW
January	334	0	0	642	976
February	288	0	0	498	786
March	229	1	0	460	690
April	216	2	0	535	753
May	279	2	0	408	689
June	203	2	0	1091	1296
July	217	2	0	668	887
August	157	2	0	445	604
September	197	1	0	391	589
October	174	1	0	481	656
November	227	0	0	512	740
December	376	0	0	547	924
Average	242	1	0	556	799
Maximum	867	14	0	1352	2058
Minimum	0	0	0	6	232
Total for the whole year TWh/year	2,12	0,01	0,00	4,88	7,02

Own use of heat from industrial CHP: 0,00 TWh/year

ANNUAL COSTS (Million NOK)

Total Fuel ex Ngas exchange =		113978
Uranium =	0	
Coal =	1674	
FuelOil =	66680	
Gasoil/Diesel=	28293	
Petrol/JP =	13726	
Gas handling =	782	
Biomass =	3575	
Food income =	0	
Waste =	-753	
Total Ngas Exchange costs =		23474
Marginal operation costs =		510
Total Electricity exchange =		-1322
Import =	0	
Export =	-1322	
Bottleneck =	0	
Fixed imp/ex=	0	
Total CO2 emission costs =		5900
Total variable costs =		142540
Fixed operation costs =		5258
Annual Investment costs =		16970
TOTAL ANNUAL COSTS =		164769

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	2	374	0	559	171	9529	10636	0	0	0	0	0	0	10636	10636	0
February	2	376	0	550	171	9529	10628	0	0	0	0	0	0	10628	10628	0
March	0	283	0	461	171	9529	10445	0	0	0	0	0	0	10445	10445	0
April	0	42	0	364	171	9529	10106	0	0	0	0	0	0	10106	10106	0
May	0	2	0	251	171	9529	9953	0	0	0	0	0	0	9953	9953	0
June	0	0	0	180	171	9529	9881	0	0	0	0	0	0	9881	9881	0
July	0	0	0	140	171	9529	9840	0	0	0	0	0	0	9840	9840	0
August	0	0	0	144	171	9529	9844	0	0	0	0	0	0	9844	9844	0
September	0	0	0	211	171	9529	9912	0	0	0	0	0	0	9912	9912	0
October	0	67	0	302	171	9529	10070	0	0	0	0	0	0	10070	10070	0
November	0	269	0	435	171	9529	10404	0	0	0	0	0	0	10404	10404	0
December	0	315	0	508	171	9529	10524	0	0	0	0	0	0	10524	10524	0
Average	0	143	0	341	171	9529	10186	0	0	0	0	0	0	10186	10186	0
Maximum	20	417	0	690	171	9529	10827	0	0	0	0	0	0	10827	10827	0
Minimum	0	0	0	118	171	9529	9818	0	0	0	0	0	0	9818	9818	0
Total for the whole year TWh/year	0,00	1,26	0,00	3,00	1,50	83,70	89,47	0,00	0,00	0,00	0,00	0,00	0,00	89,47	89,47	0,00

RES Share: 28,7 Percent of Primary Energy 143,3 Percent of Electricity 140,9 TWh electricity from RES 02-juni-2017 [06:26]

Input Norway_DH_25_biomass.txt — The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	96,91	Fixed imp/exp.	0,00
Electric heating + HP	23,35	Transportation	0,27
Electric cooling	1,00	Total	121,53

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	14,20	0,00	14,20
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	14,20	0,00	14,20

Wind	867 MW	2,12	TWh/year	0,00	Grid
Photo Voltaic	14 MW	0,01	TWh/year	0,00	stabili-
Wave Power	0 MW	0	TWh/year	0,00	sation
River Hydro	0 MW	4,88	TWh/year	0,00	share
Hydro Power	30020 MW	133,57	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	100	275	0,24	0,66	
Heat Pump	326	437			1,34
Boiler		3201		0,83	
Group 3:					
CHP	0	0	0,36	0,45	
Heat Pump	0	0			3,00
Boiler		0		0,83	
Condensing	0		0,45		

Heatstorage: gr.2: 4 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 0,0 Per cent gr.3: 0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,35
Gr.3:	0,00	0,00

Regulation Strategy:	Technical regulation no. 2	
CEEP regulation	210000000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	1,00	
Maximum import/export	8895	MW
Dis\Energinet_no_NOKprices_2015.txt		
Addition factor	0,00	NOK/MWh
Multiplication factor	1,00	
Dependency factor	0,00	NOK/MWh pr. MW
Average Market Price	177	NOK/MWh
Gas Storage	0	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0,80	
Hydro Turbine:	0		0,90	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:		0,000		

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	59,43	1,50	0,00
Household	1,81	4,89	3,00	7,23
Industry	10,00	8,23	11,99	1,96
Various	4,51	206,15	71,71	0,00

Output

District Heating

	Demand Distr. heating MW	Production Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW
January	2660	0	562	0	135	437	0	1527	0	0
February	2615	0	562	0	113	437	0	1503	0	0
March	2195	0	562	0	58	437	0	1139	0	0
April	1734	1	562	0	1	437	0	734	0	0
May	1192	1	562	0	2	437	0	190	0	2
June	857	1	562	0	0	299	0	0	0	-5
July	665	0	562	0	0	102	0	0	0	0
August	684	0	562	0	0	123	0	0	0	-1
September	1006	1	562	0	1	425	0	16	0	1
October	1438	0	562	0	31	437	0	404	0	4
November	2069	0	562	0	90	437	0	981	0	0
December	2418	0	562	0	99	437	0	1321	0	0
Average	1625	0	562	0	44	369	0	649	0	0
Maximum	3276	2	562	0	275	437	0	2003	0	168
Minimum	562	0	562	0	0	0	0	0	0	-194
TWh/year	14,27	0,00	4,93	0,00	0,39	3,25	0,00	5,70	0,00	0,00

Electricity / Exchange

	Consumption Elec. demand MW	Flex.& Transp. MW	HP MW	Elec- trolyser MW	EH MW	Hydro Pump MW	Production Tur- bine MW	RES MW	Hy- dro MW	Geo- thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Balance Stab- Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Payment Imp Million NOK	Exp Million NOK
January	11364	31	1541	0	3135	0	0	976	15625	0	40	49	0	100	0	618	0	618	0	108
February	11174	31	1521	0	3083	0	0	786	15582	0	40	41	0	100	0	640	0	640	0	101
March	11080	31	1329	0	2587	0	0	690	15250	0	40	21	0	100	0	975	0	975	0	154
April	10378	31	1118	0	2043	0	0	753	15025	0	40	0	0	100	0	2248	0	2248	0	350
May	11184	31	871	0	1405	0	0	689	15025	0	40	1	0	100	0	2264	0	2264	0	299
June	11344	31	615	0	1010	0	0	1296	14942	0	40	0	0	100	0	3278	0	3278	0	261
July	10838	31	380	0	782	0	0	887	14900	0	40	0	0	100	0	3796	0	3796	0	216
August	11145	31	404	0	805	0	0	604	14948	0	40	0	0	100	0	3207	0	3207	0	242
September	11028	31	777	0	1185	0	0	589	14997	0	40	0	0	100	0	2605	0	2605	0	209
October	11467	31	983	0	1695	0	0	656	15121	0	40	11	0	100	0	1654	0	1654	0	216
November	11562	31	1271	0	2439	0	0	740	15552	0	40	33	0	100	0	1061	0	1061	0	153
December	11187	31	1431	0	2850	0	0	924	15519	0	40	36	0	100	0	1020	0	1020	0	90
Average	11147	31	1018	0	1915	0	0	799	15206	0	40	16	0	100	0	1951	0	1951	Average price	
Maximum	14611	61	1825	0	3868	0	0	2058	18644	0	40	100	0	100	0	5696	0	5696	(NOK/MWh)	
Minimum	8391	0	257	0	662	0	0	232	14747	0	40	0	0	100	0	0	0	0	-	140
TWh/year	97,91	0,27	8,94	0,00	16,82	0,00	0,00	7,02	133,57	0,00	0,35	0,14	0,00		0,00	17,13	0,00	17,13	0	2401

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon- version	Electro- Fuel	Wind	PV	Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	1,81	14,51	16,32	0,00	16,32	5,52	5,52
Oil	-	-	-	0,09	-	0,00	-	-	-	-	-	-	-	-	-	-	-	59,43	4,89	214,38	278,79	0,00	278,79	73,85	73,85
N.Gas	-	0,58	-	0,22	-	0,00	-	-	-	-	-	-	-	-	-	-	-	1,53	3,00	83,70	89,04	0,00	89,04	18,25	18,26
Biomass	-	-	-	6,56	-	0,00	-	-	4,86	-	-	-	-	-	-	-	-	-	7,23	1,96	20,60	0,00	20,60	0,64	0,64
Renewable	-	-	-	-	-	-	-	133,57	-	-	-	-	2,12	0,01	-	-	0,02	-	-	-	140,60	0,00	140,60	0,00	0,00
H2 etc.	-	0,00	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-1,70	-	-	-	-	-	-	1,70	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	0,58	-	6,87	-	0,00	-	133,57	4,86	-	-1,70	-	2,12	0,01	-	-	0,02	62,66	16,92	314,56	545,36	-38,08	507,28	98,27	98,27

02-juni-2017 [06:27]

Output specifications Norway_DH_25_biomass.txt The EnergyPLAN model 12.4

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	0	0	0	0	2660	0	562	135	437	0	1527	0	1571	0
February	0	0	0	0	2615	0	562	113	437	0	1503	0	1571	0
March	0	0	0	0	2195	0	562	58	437	0	1139	0	1571	0
April	0	0	0	0	1734	1	562	1	437	0	734	0	1571	0
May	0	0	0	0	1192	1	562	2	437	0	190	0	1089	2
June	0	0	0	0	857	1	562	0	299	0	0	0	3273	-5
July	0	0	0	0	665	0	562	0	102	0	0	0	3389	0
August	0	0	0	0	684	0	562	0	123	0	0	0	3546	-1
September	0	0	0	0	1006	1	562	1	425	0	16	0	2127	1
October	0	0	0	0	1438	0	562	31	437	0	404	0	444	4
November	0	0	0	0	2069	0	562	90	437	0	981	0	100	0
December	0	0	0	0	2418	0	562	99	437	0	1321	0	100	0
Average	0	0	0	0	1625	0	562	44	369	0	649	0	1696	0
Maximum	0	0	0	0	3276	2	562	275	437	0	2003	0	4300	168
Minimum	0	0	0	0	562	0	562	0	0	0	0	0	0	-194
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	14,27	0,00	4,93	0,39	3,25	0,00	5,70	0,00		0,00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW
January	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0	0
Maximum	0	0	0	0	0	0	0	0	0	0
Minimum	0	0	0	0	0	0	0	0	0	0
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00

RES specification

	RES1 Wind MW	RES2 Photo V MW	RES3 Wave P MW	RES 4-7 er MW	Total MW
January	334	0	0	642	976
February	288	0	0	498	786
March	229	1	0	460	690
April	216	2	0	535	753
May	279	2	0	408	689
June	203	2	0	1091	1296
July	217	2	0	668	887
August	157	2	0	445	604
September	197	1	0	391	589
October	174	1	0	481	656
November	227	0	0	512	740
December	376	0	0	547	924
Average	242	1	0	556	799
Maximum	867	14	0	1352	2058
Minimum	0	0	0	6	232
Total for the whole year TWh/year	2,12	0,01	0,00	4,88	7,02

Own use of heat from industrial CHP: 0,00 TWh/year

ANNUAL COSTS (Million NOK)

Total Fuel ex Ngas exchange =		115701
Uranium =	0	
Coal =	1674	
FuelOil =	66714	
Gasoil/Diesel=	28293	
Petrol/JP =	13726	
Gas handling =	765	
Biomass =	5282	
Food income =	0	
Waste =	-753	
Total Ngas Exchange costs =		23353
Marginal operation costs =		574
Total Electricity exchange =		-2401
Import =	0	
Export =	-2401	
Bottleneck =	0	
Fixed imp/ex=	0	
Total CO2 emission costs =		5896
Total variable costs =		143124
Fixed operation costs =		6607
Annual Investment costs =		18461
TOTAL ANNUAL COSTS =		168191

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	58	204	0	559	171	9529	10522	0	0	0	0	0	0	10522	10522	0
February	57	171	0	550	171	9529	10479	0	0	0	0	0	0	10479	10479	0
March	44	88	0	461	171	9529	10293	0	0	0	0	0	0	10293	10293	0
April	28	2	0	364	171	9529	10095	0	0	0	0	0	0	10095	10095	0
May	7	2	0	251	171	9529	9961	0	0	0	0	0	0	9961	9961	0
June	0	0	0	180	171	9529	9881	0	0	0	0	0	0	9881	9881	0
July	0	0	0	140	171	9529	9840	0	0	0	0	0	0	9840	9840	0
August	0	0	0	144	171	9529	9844	0	0	0	0	0	0	9844	9844	0
September	1	1	0	211	171	9529	9913	0	0	0	0	0	0	9913	9913	0
October	15	47	0	302	171	9529	10065	0	0	0	0	0	0	10065	10065	0
November	37	136	0	435	171	9529	10309	0	0	0	0	0	0	10309	10309	0
December	50	149	0	508	171	9529	10409	0	0	0	0	0	0	10409	10409	0
Average	25	66	0	341	171	9529	10133	0	0	0	0	0	0	10133	10133	0
Maximum	77	417	0	690	171	9529	10883	0	0	0	0	0	0	10883	10883	0
Minimum	0	0	0	118	171	9529	9818	0	0	0	0	0	0	9818	9818	0
Total for the whole year TWh/year	0,22	0,58	0,00	3,00	1,50	83,70	89,01	0,00	0,00	0,00	0,00	0,00	0,00	89,01	89,01	0,00

RES Share: 29,6 Percent of Primary Energy 113,5 Percent of Electricity 140,9 TWh electricity from RES 02-juni-2017 [06:27]

Input Norway_DH_25_electricity.txt — The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	96,91	Fixed imp/exp.	0,00
Electric heating + HP	23,35	Transportation	0,27
Electric cooling	1,00	Total	121,53

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	14,20	0,00	14,20
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	14,20	0,00	14,20

Wind	867	MW	2,12	TWh/year	0,00	Grid
Photo Voltaic	14	MW	0,01	TWh/year	0,00	stabili-
Wave Power	0	MW	0	TWh/year	0,00	sation
River Hydro	0	MW	4,88	TWh/year	0,00	share
Hydro Power	30020	MW	133,57	TWh/year		
Geothermal/Nuclear	0	MW	0	TWh/year		

	Capacities MW-e	Capacities MJ/s	Efficiencies elec.	Efficiencies Ther	COP
Group 2:					
CHP	100	275	0,24	0,66	
Heat Pump	822	1921			2,34
Boiler		1414		0,83	
Group 3:					
CHP	0	0	0,36	0,45	
Heat Pump	0	0			3,00
Boiler		0		0,83	
Condensing	0		0,45		

Heatstorage: gr.2: 9 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 0,0 Per cent gr.3: 0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,35
Gr.3:	0,00	0,00

Regulation Strategy:	Technical regulation no. 2	
CEEP regulation	210000000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	1,00	
Maximum import/export	8895	MW

DistEnerginet_no_NOKprices_2015.txt

Addition factor	0,00	NOK/MWh
Multiplication factor	1,00	
Dependency factor	0,00	NOK/MWh pr. MW
Average Market Price	177	NOK/MWh
Gas Storage	0	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Efficiencies Ther.
Hydro Pump:	0	0	0,80	
Hydro Turbine:	0		0,90	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:	0,000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	59,43	1,50	0,00
Household	1,81	4,89	3,00	7,23
Industry	10,00	8,23	11,99	1,96
Various	4,51	206,15	71,71	0,00

Output

	District Heating: Demand Distr. heating MW	Production: Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW	Electricity Consumption: Elec. demand MW	Flex.& Transp. MW	HP MW	Electrolyser MW	EH MW	Hydro Pump MW	Production: Turbine MW	RES MW	Hydro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Balance: Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Exchange Payment Imp Million NOK	Exp Million NOK
January	2660	0	562	0	163	1905	0	33	0	-3	11364	31	2031	0	3135	0	0	976	15882	0	40	59	0	100	0	397	0	397	0	69
February	2615	0	562	0	149	1871	0	30	0	3	11174	31	1996	0	3083	0	0	786	15804	0	40	54	0	100	0	401	0	401	0	62
March	2195	0	562	0	84	1551	0	0	0	-2	11080	31	1667	0	2587	0	0	690	15321	0	40	31	0	100	0	718	0	718	0	112
April	1734	1	562	0	3	1168	0	0	0	0	10378	31	1292	0	2043	0	0	753	14954	0	40	1	0	100	0	2003	0	2003	0	311
May	1192	1	562	0	2	628	0	0	0	0	11184	31	814	0	1405	0	0	689	14927	0	40	1	0	100	0	2223	0	2223	0	293
June	857	1	562	0	0	295	0	0	0	0	11344	31	518	0	1010	0	0	1296	14798	0	40	0	0	100	0	3232	0	3232	0	258
July	665	0	562	0	0	102	0	0	0	0	10838	31	347	0	782	0	0	887	14743	0	40	0	0	100	0	3671	0	3671	0	209
August	684	0	562	0	0	121	0	0	0	0	11145	31	364	0	805	0	0	604	14813	0	40	0	0	100	0	3112	0	3112	0	235
September	1006	1	562	0	0	443	0	0	0	0	11028	31	649	0	1185	0	0	589	14878	0	40	0	0	100	0	2614	0	2614	0	210
October	1438	0	562	0	33	843	0	0	0	0	11467	31	1018	0	1695	0	0	656	15061	0	40	12	0	100	0	1559	0	1559	0	203
November	2069	0	562	0	105	1403	0	0	0	0	11562	31	1546	0	2439	0	0	740	15635	0	40	38	0	100	0	875	0	875	0	125
December	2418	0	562	0	119	1733	0	5	0	3	11187	31	1847	0	2850	0	0	924	15676	0	40	43	0	100	0	768	0	768	0	65
Average	1625	0	562	0	55	1002	0	5	0	0	11147	31	1171	0	1915	0	0	799	15206	0	40	20	0	100	0	1801	0	1801	Average price	
Maximum	3276	2	562	0	275	1921	0	400	0	280	14611	61	2322	0	3868	0	0	2058	19140	0	40	100	0	100	0	5510	0	5510	(NOK/MWh)	
Minimum	562	0	562	0	0	0	0	0	0	-445	8391	0	257	0	662	0	0	232	14510	0	40	0	0	100	0	0	0	0	-	136
TWh/year	14,27	0,00	4,93	0,00	0,48	8,81	0,00	0,04	0,00	0,00	97,91	0,27	10,29	0,00	16,82	0,00	0,00	7,02	133,57	0,00	0,35	0,17	0,00		0,00	15,82	0,00	15,82	0	2155

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	Wind	PV	Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	-	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	1,81	14,51	16,32	0,00	16,32	5,52	5,52
Oil	-	-	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	59,43	4,89	214,38	278,70	0,00	278,70	73,83	73,83
N.Gas	-	0,73	-	0,01	-	0,00	-	-	-	-	-	-	-	-	-	-	-	1,53	3,00	83,70	88,97	0,00	88,97	18,24	18,25
Biomass	-	-	-	0,05	-	0,00	-	-	4,86	-	-	-	-	-	-	-	-	-	7,23	1,96	14,09	0,00	14,09	0,64	0,64
Renewable	-	-	-	-	-	-	-	133,57	-	-	-	-	2,12	0,01	-	-	0,02	-	-	-	140,60	0,00	140,60	0,00	0,00
H2 etc.	-	0,00	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-1,70	-	-	-	-	-	-	1,70	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	0,73	-	0,05	-	0,00	-	133,57	4,86	-	-1,70	-	2,12	0,01	-	-	0,02	62,66	16,92	314,56	538,69	-35,16	503,53	98,23	98,24

02-juni-2017 [06:28]

Output specifications   Norway_DH_25_electricity.txt   The EnergyPLAN model 12.4

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW	RES specification RES1 Wind MW	RES2 Photo \ MW	RES3 Wave I MW	RES 4-7 MW	Total MW
January	0	0	0	0	2660	0	562	163	1905	0	33	0	4394	-3	0	0	0	0	0	0	0	0	0	0	334	0	0	642	976
February	0	0	0	0	2615	0	562	149	1871	0	30	0	2572	3	0	0	0	0	0	0	0	0	0	0	288	0	0	498	786
March	0	0	0	0	2195	0	562	84	1551	0	0	0	3604	-2	0	0	0	0	0	0	0	0	0	0	229	1	0	460	690
April	0	0	0	0	1734	1	562	3	1168	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	216	2	0	535	753
May	0	0	0	0	1192	1	562	2	628	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	279	2	0	408	689
June	0	0	0	0	857	1	562	0	295	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	203	2	0	1091	1296
July	0	0	0	0	665	0	562	0	102	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	217	2	0	668	887
August	0	0	0	0	684	0	562	0	121	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	157	2	0	445	604
September	0	0	0	0	1006	1	562	0	443	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	197	1	0	391	589
October	0	0	0	0	1438	0	562	33	843	0	0	0	3830	0	0	0	0	0	0	0	0	0	0	0	174	1	0	481	656
November	0	0	0	0	2069	0	562	105	1403	0	0	0	3838	0	0	0	0	0	0	0	0	0	0	0	227	0	0	512	740
December	0	0	0	0	2418	0	562	119	1733	0	0	0	4276	3	0	0	0	0	0	0	0	0	0	0	376	0	0	547	924
Average	0	0	0	0	1625	0	562	55	1002	0	5	0	3798	0	0	0	0	0	0	0	0	0	0	0	242	1	0	556	799
Maximum	0	0	0	0	3276	2	562	275	1921	0	400	0	9300	280	0	0	0	0	0	0	0	0	0	0	867	14	0	1352	2058
Minimum	0	0	0	0	562	0	562	0	0	0	0	0	0	-445	0	0	0	0	0	0	0	0	0	0	0	0	0	6	232
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	14,27	0,00	4,93	0,48	8,81	0,00	0,04	0,00		0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00	2,12	0,01	0,00	4,88	7,02

Own use of heat from industrial CHP: 0,00 TWh/year

ANNUAL COSTS (Million NOK)

Total Fuel ex Ngas exchange = 113962
- Uranium = 0
- Coal = 1674
- FuelOil = 66680
- Gasoil/Diesel= 28293
- Petrol/JP = 13726
- Gas handling = 763
- Biomass = 3579
- Food income = 0
- Waste = -753

Total Ngas Exchange costs = 23335

Marginal operation costs = 529

Total Electricity exchange = -2155
- Import = 0
- Export = -2155
- Bottleneck = 0
- Fixed imp/ex= 0

Total CO2 emission costs = 5894

Total variable costs = 141566

Fixed operation costs = 5705

Annual Investment costs = 17869

TOTAL ANNUAL COSTS = 165141

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	4	247	0	559	171	9529	10510	0	0	0	0	0	0	10510	10510	0
February	3	226	0	550	171	9529	10480	0	0	0	0	0	0	10480	10480	0
March	0	127	0	461	171	9529	10289	0	0	0	0	0	0	10289	10289	0
April	0	5	0	364	171	9529	10070	0	0	0	0	0	0	10070	10070	0
May	0	3	0	251	171	9529	9954	0	0	0	0	0	0	9954	9954	0
June	0	0	0	180	171	9529	9881	0	0	0	0	0	0	9881	9881	0
July	0	0	0	140	171	9529	9840	0	0	0	0	0	0	9840	9840	0
August	0	0	0	144	171	9529	9844	0	0	0	0	0	0	9844	9844	0
September	0	1	0	211	171	9529	9912	0	0	0	0	0	0	9912	9912	0
October	0	50	0	302	171	9529	10053	0	0	0	0	0	0	10053	10053	0
November	0	159	0	435	171	9529	10294	0	0	0	0	0	0	10294	10294	0
December	0	181	0	508	171	9529	10390	0	0	0	0	0	0	10390	10390	0
Average	1	83	0	341	171	9529	10125	0	0	0	0	0	0	10125	10125	0
Maximum	45	417	0	690	171	9529	10848	0	0	0	0	0	0	10848	10848	0
Minimum	0	0	0	118	171	9529	9818	0	0	0	0	0	0	9818	9818	0
Total for the whole year TWh/year	0,01	0,73	0,00	3,00	1,50	83,70	88,94	0,00	0,00	0,00	0,00	0,00	0,00	88,94	88,94	0,00

RES Share: 28,7 Percent of Primary Energy 119,7 Percent of Electricity 140,9 TWh electricity from RES 02-juni-2017 [06:28]

Input   Norway_DH_50_electricity.txt   The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	96,91	Fixed imp/exp.	0,00
Electric heating + HP	15,57	Transportation	0,27
Electric cooling	1,00	Total	113,76

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	22,97	0,00	22,97
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	22,97	0,00	22,97

Wind	867 MW	2,12	TWh/year	0,00	Grid
Photo Voltaic	14 MW	0,01	TWh/year	0,00	stabili-
Wave Power	0 MW	0	TWh/year	0,00	sation
River Hydro	0 MW	4,88	TWh/year	0,00	share
Hydro Power	30020 MW	133,57	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	100	275	0,24	0,66	
Heat Pump	1381	3592			2,60
Boiler		1899		0,83	
Group 3:					
CHP	0	0	0,36	0,45	
Heat Pump	0	0			3,00
Boiler		0		0,83	
Condensing	0		0,45		

Heatstorage: gr.2: 6 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 0,0 Per cent gr.3: 0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,35
Gr.3:	0,00	0,00

Regulation Strategy:	Technical regulation no. 2	
CEEP regulation	210000000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	1,00	
Maximum import/export	8895	MW

DistEnerginet_no_NOKprices_2015.txt		
Addition factor	0,00	NOK/MWh
Multiplication factor	1,00	
Dependency factor	0,00	NOK/MWh pr. MW
Average Market Price	177	NOK/MWh
Gas Storage	0	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0,80	
Hydro Turbine:	0		0,90	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:	0,000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	59,43	1,50	0,00
Household	1,81	4,89	3,00	7,23
Industry	10,00	8,23	11,99	1,96
Various	4,51	206,15	71,71	0,00

Output

	District Heating										Electricity																		Exchange	
	Demand	Production									Consumption						Production							Balance					Payment	
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba-lance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Imp Million NOK	Exp
January	4294	0	907	0	173	3210	0	8	0	-4	12550	31	2449	0	1686	0	0	976	16018	0	40	63	0	100	0	379	0	379	0	66
February	4222	0	907	0	160	3143	0	13	0	0	12341	31	2403	0	1658	0	0	786	15922	0	40	58	0	100	0	374	0	374	0	58
March	3544	0	907	0	69	2568	0	0	0	0	11766	31	1990	0	1391	0	0	690	15285	0	40	25	0	100	0	863	0	863	0	136
April	2799	1	907	0	0	1892	0	0	0	0	10640	31	1519	0	1099	0	0	753	14979	0	40	0	0	100	0	2483	0	2483	0	387
May	1925	1	907	0	0	1018	0	0	0	0	10667	31	936	0	755	0	0	689	14909	0	40	0	0	100	0	3249	0	3249	0	440
June	1384	1	907	0	0	477	0	0	0	0	10403	31	575	0	543	0	0	1296	14788	0	40	0	0	100	0	4573	0	4573	0	376
July	1073	1	907	0	0	166	0	0	0	0	9756	31	367	0	421	0	0	887	14741	0	40	0	0	100	0	5093	0	5093	0	293
August	1104	1	907	0	0	196	0	0	0	0	10033	31	388	0	433	0	0	604	14790	0	40	0	0	100	0	4550	0	4550	0	346
September	1624	1	907	0	0	716	0	0	0	0	10317	31	735	0	637	0	0	589	14861	0	40	0	0	100	0	3771	0	3771	0	308
October	2322	0	907	0	3	1411	0	0	0	0	11191	31	1200	0	911	0	0	656	14992	0	40	1	0	100	0	2356	0	2356	0	317
November	3341	0	907	0	87	2347	0	0	0	0	12016	31	1848	0	1312	0	0	740	15510	0	40	32	0	100	0	1115	0	1115	0	161
December	3904	0	907	0	118	2877	0	0	0	1	12118	31	2211	0	1533	0	0	924	15700	0	40	43	0	100	0	815	0	815	0	69
Average	2623	0	907	0	51	1664	0	2	0	0	11147	31	1382	0	1030	0	0	799	15206	0	40	18	0	100	0	2474	0	2474	Average price (NOK/MWh)	
Maximum	5292	3	907	0	275	3592	0	515	0	519	15481	61	2880	0	2080	0	0	2058	19375	0	40	100	0	100	0	6743	0	6743		
Minimum	907	0	907	0	0	0	0	0	0	-292	8241	0	257	0	356	0	0	232	14590	0	40	0	0	100	0	0	0	0	-	136
TWh/year	23,04	0,00	7,96	0,00	0,44	14,62	0,00	0,01	0,00	0,00	97,91	0,27	12,14	0,00	9,04	0,00	0,00	7,02	133,57	0,00	0,35	0,16	0,00		0,00	21,73	0,00	21,73	0	2957

FUEL BALANCE (TWh/year):	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	Wind	PV	Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	-	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	1,81	14,51	16,32	0,00	16,32	5,52	5,52
Oil	-	-	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	59,43	4,89	214,38	278,70	0,00	278,70	73,83	73,83
N.Gas	-	0,67	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	1,53	3,00	83,70	88,91	0,00	88,91	18,23	18,23
Biomass	-	-	-	0,02	-	0,00	-	-	4,86	-	-	-	-	-	-	-	-	-	7,23	1,96	14,06	0,00	14,06	0,64	0,64
Renewable	-	-	-	-	-	-	-	133,57	-	-	-	-	2,12	0,01	-	-	0,02	-	-	-	140,60	0,00	140,60	0,00	0,00
H2 etc.	-	0,00	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-1,70	-	-	-	-	-	-	1,70	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	0,67	-	0,02	-	0,00	-	133,57	4,86	-	-1,70	-	2,12	0,01	-	-	0,02	62,66	16,92	314,56	538,60	-48,30	490,30	98,22	98,22

02-juni-2017 [06:29]

Output specifications Norway_DH_50_electricity.txt The EnergyPLAN model 12.4

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Storage MW	Gr.2 Balance MW
January	0	0	0	0	4294	0	907	173	3210	0	8	0	3943	-4
February	0	0	0	0	4222	0	907	160	3143	0	13	0	5161	0
March	0	0	0	0	3544	0	907	69	2568	0	0	0	6400	0
April	0	0	0	0	2799	1	907	0	1892	0	0	0	6400	0
May	0	0	0	0	1925	1	907	0	1018	0	0	0	6400	0
June	0	0	0	0	1384	1	907	0	477	0	0	0	6400	0
July	0	0	0	0	1073	1	907	0	166	0	0	0	6400	0
August	0	0	0	0	1104	1	907	0	196	0	0	0	6400	0
September	0	0	0	0	1624	1	907	0	716	0	0	0	6400	0
October	0	0	0	0	2322	0	907	3	1411	0	0	0	6400	0
November	0	0	0	0	3341	0	907	87	2347	0	0	0	6400	0
December	0	0	0	0	3904	0	907	118	2877	0	0	0	5804	1
Average	0	0	0	0	2623	0	907	51	1664	0	2	0	6043	0
Maximum	0	0	0	0	5292	3	907	275	3592	0	515	0	6400	519
Minimum	0	0	0	0	907	0	907	0	0	0	0	0	0	-292
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	23,04	0,00	7,96	0,44	14,62	0,00	0,01	0,00		0,00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Storage MW	Gr.3 Balance MW	RES1 Wind MW	RES2 Photo \ MW	RES3 Wave I MW	RES 4-7 :r MW	Total MW
January	0	0	0	0	0	0	0	0	0	0	334	0	0	642	976
February	0	0	0	0	0	0	0	0	0	0	288	0	0	498	786
March	0	0	0	0	0	0	0	0	0	0	229	1	0	460	690
April	0	0	0	0	0	0	0	0	0	0	216	2	0	535	753
May	0	0	0	0	0	0	0	0	0	0	279	2	0	408	689
June	0	0	0	0	0	0	0	0	0	0	203	2	0	1091	1296
July	0	0	0	0	0	0	0	0	0	0	217	2	0	668	887
August	0	0	0	0	0	0	0	0	0	0	157	2	0	445	604
September	0	0	0	0	0	0	0	0	0	0	197	1	0	391	589
October	0	0	0	0	0	0	0	0	0	0	174	1	0	481	656
November	0	0	0	0	0	0	0	0	0	0	227	0	0	512	740
December	0	0	0	0	0	0	0	0	0	0	376	0	0	547	924
Average	0	0	0	0	0	0	0	0	0	0	242	1	0	556	799
Maximum	0	0	0	0	0	0	0	0	0	0	867	14	0	1352	2058
Minimum	0	0	0	0	0	0	0	0	0	0	0	0	0	6	232
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00	2,12	0,01	0,00	4,88	7,02

Own use of heat from industrial CHP: 0,00 TWh/year

ANNUAL COSTS (Million NOK)

Total Fuel ex Ngas exchange =		113951
Uranium =	0	
Coal =	1674	
FuelOil =	66680	
Gasoil/Diesel=	28293	
Petrol/JP =	13726	
Gas handling =	760	
Biomass =	3571	
Food income =	0	
Waste =	-753	
Total Ngas Exchange costs =		23320
Marginal operation costs =		543
Total Electricity exchange =		-2957
Import =	0	
Export =	-2957	
Bottleneck =	0	
Fixed imp/ex=	0	
Total CO2 emission costs =		5893
Total variable costs =		140750
Fixed operation costs =		6000
Annual Investment costs =		18658
TOTAL ANNUAL COSTS =		165407

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Individual MW	Transport MW	Indu. Var. MW	Demand Sum MW	Biogas MW	Syngas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Storage MW	Sum MW	Import MW	Export MW
January	1	261	0	559	171	9529	10522	0	0	0	0	0	0	10522	10522	0
February	1	242	0	550	171	9529	10494	0	0	0	0	0	0	10494	10494	0
March	0	105	0	461	171	9529	10267	0	0	0	0	0	0	10267	10267	0
April	0	0	0	364	171	9529	10065	0	0	0	0	0	0	10065	10065	0
May	0	0	0	251	171	9529	9951	0	0	0	0	0	0	9951	9951	0
June	0	0	0	180	171	9529	9881	0	0	0	0	0	0	9881	9881	0
July	0	0	0	140	171	9529	9840	0	0	0	0	0	0	9840	9840	0
August	0	0	0	144	171	9529	9844	0	0	0	0	0	0	9844	9844	0
September	0	0	0	211	171	9529	9912	0	0	0	0	0	0	9912	9912	0
October	0	5	0	302	171	9529	10008	0	0	0	0	0	0	10008	10008	0
November	0	132	0	435	171	9529	10267	0	0	0	0	0	0	10267	10267	0
December	0	179	0	508	171	9529	10388	0	0	0	0	0	0	10388	10388	0
Average	0	77	0	341	171	9529	10119	0	0	0	0	0	0	10119	10119	0
Maximum	58	417	0	690	171	9529	10864	0	0	0	0	0	0	10864	10864	0
Minimum	0	0	0	118	171	9529	9818	0	0	0	0	0	0	9818	9818	0
Total for the whole year TWh/year	0,00	0,67	0,00	3,00	1,50	83,70	88,88	0,00	0,00	0,00	0,00	0,00	0,00	88,88	88,88	0,00

RES Share: 28,7 Percent of Primary Energy 117,8 Percent of Electricity 140,9 TWh electricity from RES 02-juni-2017 [06:29]

Input Norway_DH_100_electric.txt

The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	96,91	Fixed imp/exp.	0,00
Electric heating + HP	0,00	Transportation	0,27
Electric cooling	1,00	Total	98,18

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	50,04	0,00	50,04
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	50,04	0,00	50,04

Wind	867 MW	2,12	TWh/year	0,00	Grid
Photo Voltaic	14 MW	0,01	TWh/year	0,00	stabili-
Wave Power	0 MW	0	TWh/year	0,00	sation
River Hydro	0 MW	4,88	TWh/year	0,00	share
Hydro Power	30020 MW	133,57	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	100	275	0,24	0,66	
Heat Pump	3258	9234			2,83
Boiler		3399		0,83	
Group 3:					
CHP	0	0	0,36	0,45	
Heat Pump	0	0			3,00
Boiler		0		0,83	
Condensing	0		0,45		

Heatstorage: gr.2: 2 GWh gr.3: 0 GWh
Fixed Boiler: gr.2: 0,0 Per cent gr.3: 0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,35
Gr.3:	0,00	0,00

Regulation Strategy:	Technical regulation no. 2	
CEEP regulation	210000000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	1,00	
Maximum import/export	8895	MW

DisEnerginet_no_NOKprices_2015.txt		
Addition factor	0,00	NOK/MWh
Multiplication factor	1,00	
Dependency factor	0,00	NOK/MWh pr. MW
Average Market Price	177	NOK/MWh
Gas Storage	0	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0,80	
Hydro Turbine:	0		0,90	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:	0,000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	59,43	1,50	0,00
Household	1,81	4,89	3,00	7,23
Industry	10,00	8,23	11,99	1,96
Various	4,51	206,15	71,71	0,00

Output

District Heating

	Demand	Production								Balance
	Distr. heating MW	Solar MW	Waste+ CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Ba-lance MW
January	9338	0	1488	0	57	7793	0	1	0	-1
February	9183	0	1488	0	51	7640	0	2	0	0
March	7708	0	1488	0	7	6212	0	0	0	0
April	6089	1	1488	0	0	4600	0	0	0	0
May	4188	1	1488	0	0	2699	0	0	0	0
June	3011	1	1488	0	0	1521	0	0	0	0
July	2334	1	1488	0	0	845	0	0	0	0
August	2400	1	1488	0	0	911	0	0	0	0
September	3532	0	1488	0	0	2043	0	0	0	0
October	5050	0	1488	0	0	3561	0	0	0	0
November	7266	0	1488	0	44	5734	0	0	0	0
December	8489	0	1488	0	41	6960	0	0	0	0
Average	5705	0	1488	0	17	4199	0	0	0	0
Maximum	11515	5	1488	0	275	9234	0	417	0	517
Minimum	1972	0	1488	0	0	484	0	0	0	-33
TWh/year	50,11	0,00	13,07	0,00	0,15	36,89	0,00	0,00	0,00	0,00

Electricity

	Consumption						Production							Balance					Exchange Payment	
	Elec. demand MW	Flex.& Transp. MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste+ CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Imp Million NOK	Exp
January	12387	31	2750	0	0	0	0	976	15329	0	40	21	0	100	0	1198	0	1198	0	213
February	12180	31	2696	0	0	0	0	786	15343	0	40	19	0	100	0	1281	0	1281	0	205
March	11671	31	2192	0	0	0	0	690	15187	0	40	3	0	100	0	2026	0	2026	0	325
April	10604	31	1623	0	0	0	0	753	15159	0	40	0	0	100	0	3694	0	3694	0	580
May	10738	31	952	0	0	0	0	689	15153	0	40	0	0	100	0	4161	0	4161	0	569
June	10532	31	537	0	0	0	0	1296	15137	0	40	0	0	100	0	5374	0	5374	0	444
July	9905	31	298	0	0	0	0	887	15132	0	40	0	0	100	0	5824	0	5824	0	336
August	10186	31	321	0	0	0	0	604	15139	0	40	0	0	100	0	5245	0	5245	0	400
September	10415	31	721	0	0	0	0	589	15147	0	40	0	0	100	0	4610	0	4610	0	378
October	11229	31	1256	0	0	0	0	656	15163	0	40	0	0	100	0	3343	0	3343	0	460
November	11954	31	2023	0	0	0	0	740	15276	0	40	16	0	100	0	2065	0	2065	0	304
December	11989	31	2456	0	0	0	0	924	15311	0	40	15	0	100	0	1814	0	1814	0	172
Average	11147	31	1482	0	0	0	0	799	15206	0	40	6	0	100	0	3392	0	3392	Average price	
Maximum	15279	61	3258	0	0	0	0	2058	17475	0	40	100	0	100	0	7670	0	7670	(NOK/MWh)	
Minimum	8367	0	171	0	0	0	0	232	15108	0	40	0	0	100	0	0	0	0	-	147
TWh/year	97,91	0,27	13,02	0,00	0,00	0,00	0,00	7,02	133,57	0,00	0,35	0,05	0,00		0,00	29,79	0,00	29,79	0	4385

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	Wind	PV	Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	-	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	1,81	14,51	16,32	0,00	16,32	5,52	5,52
Oil	-	-	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	59,43	4,89	214,38	278,70	0,00	278,70	73,82	73,82
N.Gas	-	0,22	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	1,53	3,00	83,70	88,45	0,00	88,45	18,14	18,14
Biomass	-	-	-	0,00	-	0,00	-	-	4,86	-	-	-	-	-	-	-	-	-	7,23	1,96	14,05	0,00	14,05	0,64	0,64
Renewable	-	-	-	-	-	-	-	133,57	-	-	-	-	2,12	0,01	-	-	0,01	-	-	-	140,59	0,00	140,59	0,00	0,00
H2 etc.	-	0,00	-	0,00	-	0,00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-1,70	-	-	-	-	-	-	1,70	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	0,22	-	0,00	-	0,00	-	133,57	4,86	-	-1,70	-	2,12	0,01	-	-	0,01	62,66	16,92	314,56	538,12	-66,21	471,91	98,12	98,13

02-juni-2017 [06:30]

Output specifications   Norway_DH_100_electric.txt   The EnergyPLAN model 12.4

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Stor-age MW	Gr.2 Ba-lance MW
January	0	0	0	0	9338	0	1488	57	7793	0	1	0	1252	-1
February	0	0	0	0	9183	0	1488	51	7640	0	2	0	1759	0
March	0	0	0	0	7708	0	1488	7	6212	0	0	0	2100	0
April	0	0	0	0	6089	1	1488	0	4600	0	0	0	2100	0
May	0	0	0	0	4188	1	1488	0	2699	0	0	0	2100	0
June	0	0	0	0	3011	1	1488	0	1521	0	0	0	2100	0
July	0	0	0	0	2334	1	1488	0	845	0	0	0	2100	0
August	0	0	0	0	2400	1	1488	0	911	0	0	0	2100	0
September	0	0	0	0	3532	0	1488	0	2043	0	0	0	2100	0
October	0	0	0	0	5050	0	1488	0	3561	0	0	0	2100	0
November	0	0	0	0	7266	0	1488	44	5734	0	0	0	2100	0
December	0	0	0	0	8489	0	1488	41	6960	0	0	0	2100	0
Average	0	0	0	0	5705	0	1488	17	4199	0	0	0	2001	0
Maximum	0	0	0	0	11515	5	1488	275	9234	0	417	0	2100	517
Minimum	0	0	0	0	1972	0	1488	0	484	0	0	0	0	-33
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	50,11	0,00	13,07	0,15	36,89	0,00	0,00	0,00		0,00

	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Stor-age MW	Gr.3 Ba-lance MW	RES1 Wind MW	RES2 Photo V MW	RES3 Wave P MW	RES 4-7 MW	Total MW
January	0	0	0	0	0	0	0	0	0	0	334	0	0	642	976
February	0	0	0	0	0	0	0	0	0	0	288	0	0	498	786
March	0	0	0	0	0	0	0	0	0	0	229	1	0	460	690
April	0	0	0	0	0	0	0	0	0	0	216	2	0	535	753
May	0	0	0	0	0	0	0	0	0	0	279	2	0	408	689
June	0	0	0	0	0	0	0	0	0	0	203	2	0	1091	1296
July	0	0	0	0	0	0	0	0	0	0	217	2	0	668	887
August	0	0	0	0	0	0	0	0	0	0	157	2	0	445	604
September	0	0	0	0	0	0	0	0	0	0	197	1	0	391	589
October	0	0	0	0	0	0	0	0	0	0	174	1	0	481	656
November	0	0	0	0	0	0	0	0	0	0	227	0	0	512	740
December	0	0	0	0	0	0	0	0	0	0	376	0	0	547	924
Average	0	0	0	0	0	0	0	0	0	0	242	1	0	556	799
Maximum	0	0	0	0	0	0	0	0	0	0	867	14	0	1352	2058
Minimum	0	0	0	0	0	0	0	0	0	0	0	0	0	6	232
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00	2,12	0,01	0,00	4,88	7,02

Own use of heat from industrial CHP: 0,00 TWh/year

ANNUAL COSTS (Million NOK)

Total Fuel ex Ngas exchange =		113931
Uranium =	0	
Coal =	1674	
FuelOil =	66680	
Gasoil/Diesel=	28293	
Petrol/JP =	13726	
Gas handling =	743	
Biomass =	3567	
Food income =	0	
Waste =	-753	
Total Ngas Exchange costs =		23201
Marginal operation costs =		606
Total Electricity exchange =		-4385
Import =	0	
Export =	-4385	
Bottleneck =	0	
Fixed imp/ex=	0	
Total CO2 emission costs =		5887
Total variable costs =		139240
Fixed operation costs =		6911
Annual Investment costs =		21019
TOTAL ANNUAL COSTS =		167171

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	0	86	0	559	171	9529	10346	0	0	0	0	0	0	10346	10346	0
February	0	78	0	550	171	9529	10328	0	0	0	0	0	0	10328	10328	0
March	0	11	0	461	171	9529	10173	0	0	0	0	0	0	10173	10173	0
April	0	0	0	364	171	9529	10065	0	0	0	0	0	0	10065	10065	0
May	0	0	0	251	171	9529	9951	0	0	0	0	0	0	9951	9951	0
June	0	0	0	180	171	9529	9881	0	0	0	0	0	0	9881	9881	0
July	0	0	0	140	171	9529	9840	0	0	0	0	0	0	9840	9840	0
August	0	0	0	144	171	9529	9844	0	0	0	0	0	0	9844	9844	0
September	0	0	0	211	171	9529	9912	0	0	0	0	0	0	9912	9912	0
October	0	0	0	302	171	9529	10003	0	0	0	0	0	0	10003	10003	0
November	0	67	0	435	171	9529	10202	0	0	0	0	0	0	10202	10202	0
December	0	62	0	508	171	9529	10271	0	0	0	0	0	0	10271	10271	0
Average	0	25	0	341	171	9529	10067	0	0	0	0	0	0	10067	10067	0
Maximum	47	417	0	690	171	9529	10849	0	0	0	0	0	0	10849	10849	0
Minimum	0	0	0	118	171	9529	9818	0	0	0	0	0	0	9818	9818	0
Total for the whole year TWh/year	0,00	0,22	0,00	3,00	1,50	83,70	88,43	0,00	0,00	0,00	0,00	0,00	0,00	88,43	88,43	0,00

RES Share: 28,7 Percent of Primary Energy 118,2 Percent of Electricity 140,9 TWh electricity from RES

02-juni-2017 [06:30]