Modeling integration of renewable energy sources into Inland Norway energy system

Modellering av integrasjon av fornybar energi i energisystemet i Innlandet, Norge

Philosophiae Doctor (PhD) Thesis

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ABSTRACT

Increasing attention to climate change causes and impacts, and the fact that the world owns limited energy resources, have tremendously increased the awareness of countries towards sustainable energy production and utilisation. The Norwegian energy system is characterized by large shares of hydropower generation and direct electric heating, causing low emissions. Direct electric heating imply low investments costs and is easy to install and maintain. However, it destroys a huge amount of exergy - as high as 90%, is rigid in operation and may also be a source of congestion, especially during peak load periods in winter. This makes the system vulnerable to low precipitation, impede the penetration of other potential renewable energy sources (RESs) and restrict competition between heat sources due to lack of system flexibility. Also, as in most other energy systems, the renewable energy share in transportation is very low.

The main objective of this thesis is to investigate how the existing electricity-intensive system of Inland Norway could be transformed into a flexible energy system, with reduced use of fossil fuels in the transportation, through integration of various technologies and RESs. In light of this, both the value of wind energy for power supply security and the optimal use of bioenergy from techno-economic perspectives are investigated. The analyses are performed by calibrating and applying two different energy system analysis tools for Inland Norway. These tools are the EnergyPLAN model, developed at Aalborg University, and TIMES, developed at International Energy Agency.

The results reveal that, with the current and assumed energy price development, water to water heat pumps are often a more profitable solutions than bioheat in central and district heating (DH) systems. The merit order in individual heating is found to be wood stoves, air to air heat pumps and electric heating.

The study also revealed that, in an individual heating system, the availability of hydronic distribution system is essential for water to water heat pumps. For bioheat boilers also the biomass price is a major factor. In general, waterborne heating system deployment is found to be less competitive over direct heating, and regulatory or strong market based polices must be implemented to increase the share of waterborne heating systems.

The techno-economic study showed that despite the high investment costs required to establish an alternative flexible heating system, the revenue from electricity trade due to energy carrier switching and increased energy efficiency offsets a large part of payments and makes the incremental costs marginal.

The societal value of wind energy is expressed by reducing imports during peak demand and low precipitation periods in winter. Also, wind power has a moderate capacity

credit - as high as 21% - at lower penetration level in Inland Norway.

In this study, a DH integrated biorefinery is proposed and analysed for increased use of bioenergy in a future energy system of Inland Norway. Techno-economically, the use of bioenergy as biofuel for reduced emissions from fossil fuels in the transport sector is found to be feasible with a certain subsidy level. The biorefinery is found not only to increase the use of bioenergy but also create a synergy effect between electricity, heat and transport sectors through integration of technologies and RESs. However, due its high investment cost, for the base case price scenario, a minimum of 6 €/GJ biofuel subsidy is required to initiate investments in a dimethyl ether (DME)-biorefinery. For a higher energy price scenario (biomass and electricity), Fischer-Tropsch (FT)-biodiesel is found to be profitable over DME and requires a minimum of 12 €/GJ biofuel subsidy. The profitability of biomass-combined heat and power (CHP) in DH largely depends on the electricity price rather than the biomass price, and an average electricity price higher than 9.85 €/GJ is required to make it profitable. Given that biorefinery and CHP are competing technologies, the existence of tradable green certificates (TGC) for renewable power generation happens to increase the required level of biofuel subsidy. The increase is, however, marginal (1 €/GJ).

In conclusion, using heat pumps for a low-quality heat production in individual, central and DH heating systems, and earmarking biomass as biofuel for transport purposes is under most assumptions found to be a cost-effective solution in terms of achieving energy policy goals, and for rational use of limited RESs.

SAMMENDRAG

Stadig økende fokus på konsekvenser av klimaendringer, og det faktum at verden har begrensede energiressurser har bidratt til økt oppmerksomhet mot bærekraftig energiproduksjon og - utnyttelse. Det norske energisystemet kjennetegnes ved en svært stor andel vannkraft og stor bruk av direkte elektrisk oppvarming, og dermed lave klimagassutslipp. Direkte elektrisk oppvarmingssytemer har lave investeringskostnader og er enkelt å installere og vedlikeholde, men samtidig mister man store mengder eksergi - opptil 90%, systemet er lite fleksibelt i drift og også en kilde til overbelastning elnettet, spesielt under topplastperioder vinterstid. Systemet er også sårbart for lite nedbør hindrer utbredelse av andre potensielle fornybare energikilder (RES), og begrenser konkurransen mellom varmekilder grunn av manglende systemfleksibilitet. Som i de fleste andre energisystemer er fornybarandelen i transportsektoren svært lav.

Hovedmålet med denne avhandlingen er å undersøke hvordan det eksisterende energisystemet i innlandet (Oppland og Hedmark) kan videreutvikles til et mer fleksibelt energisystem, med redusert bruk av fossile brensler særlig til transport gjennom integrasjon av ulike teknologier og fornybare energikilder (RES). I lys av dette, både er vindenergiens bidrag i energisystemet og optimal bruk av bioenergi fra tekno-økonomiske perspektiv analysert. Analysene er gjennomført ved å videreutvikle, kalibrere og anvende to energisystemmodeller for innlandsregionen. Disse to modellene er EnergyPLAN, utviklet ved Aalborg Universitet, og TIMES, utviklet av International Energy Agency.

Resultatene viser at med dagens og forventede energipriser, er vann til vann varmepumper i mange tilfeller mer lønnsomt enn biovarme i sentral - og fjernvarmesystemer. For individuell oppvarming framstår vedovner som den mest lønsomme løsningen, fulgt av luft til luft varmepumper, elektrisk oppvarming.

Studien viser også at i et individuelt varmesystem er tilgjengeligheten av et vannbåret distribusjonssystem avgjørende for vann til vann varmepumper. For biovarme er også biomasseprisen en viktig faktor. Generelt er vannbårne varmesystem funnet å være mindre konkurransedyktig enn direkte oppvarming, og virkemidler er nødvendig dersom vannbårne systemer skal øke i omfang , særlig i eksiterende bygninger.

Etablering av et alternativt fleksibelt oppvarmingssystem innebærer høye investeringskostnader ved å etablere et alternativt fleksibelt oppvarmingssystem. Men økte inntekter fra økt krafteksport som følge av mindre elforbruk vil veie opp for en stor del av de økte kostnadene og gjøre merkostnadene marginale i et regionalt samfunnsperspektiv.

Studien viser videre at økt utbygging av vindkraft reduserer kraftimportbehovet i perioder med høy etterspørsel og i perioder med lav nedbør vinterstid. Ved lave utbyg-

gingsnivåer estimeres en kapasitetskreditt for vindkraft på 21% i innlandsregionen.

Studien har også analysert et integrert anlegg for fjernvarme og bioraffinering og finner at bruk av biomasse til biodrivstoff i transportsektoren er en tekno-økonomisk aktuell løsning for å redusere fossile utslipp fra transportsektoren, men det kreves et visst subsidienivå. Analysen viser at et bioraffineri ikke bare øker bruken av bioenergi, men også skaper en synergieffekt mellom elektrisitet, varme- og transportsektoren gjennom integrering av teknologier og fornybare energikilder. Det vil imidlertid være nødvendig med en subsidie på minimum på 6 €/GJ biodrivstoff for å initiere investeringer i et dimetyleter (DME)-bioraffineri, i basisscenariet. I et alternativt scenario, med høyere energipriser (biomasse og elektrisitet), er Fischer-Tropsch (FT)-biodiesel funnet å være mer lønnsomt enn DME, men det kreves da en subsidie på 12 €/GJ biodrivstoff. Lønnsomheten av kraftvarme (CHP) basert på biomasse avhenger i stor grad av kraftprisen, og en gjennomsnittlig strømpris som er høyere enn 9.85 €/GJ er nødvendig for å gjøre det lønnsomt med forutsetningene som er lagt til grunn i denne analysen. Siden bioraffineri og CHP er konkurrerende teknologier, vil elsertifikatsystemet for fornybar kraft øke subsidienivået som er nødvendig for å initiere biodrivstoffproduksjon. Økningen i krav til subsidier er imidlertid marginal (1 €/GJ).

Oppsummert så viser resultatene i denne avhandlingen viser at bruk av varmepumper i sentral - og fjernvarmesystemer, og bruk av biomasse som biobrensel til transportformål i mange tilfeller vil være en effektiv løsning for å oppnå energipolitiske mål, og for rasjonell bruk av begrensede fornybare energikilder (RES).

LIST OF PAPERS

This thesis is based on the following papers, which will be referred to by the Roman numerals in the text and included in the Appendices.

Paper I:

Dejene Assefa Hagos, Alemayehu Gebremedhin, and Björn Zethraeus, Solar Water Heating as a Potential Source for Inland Norway Energy Mix, Journal of Renewable Energy, vol. 2014, Article ID 968320, 11 pages, 2014. http://dx.doi.org/10.1155/2014/968320

Paper II:

Dejene Assefa Hagos, Alemayehu Gebremedhin, and Björn Zethraeus, Towards a flexible energy system - A case study for Inland Norway, Applied Energy, 2014. 130(0): p. 41-50. http://dx.doi.org/10.1016/j.apenergy.2014.05.022

Paper III:

Dejene Assefa Hagos, Alemayehu Gebremedhin, and Torjus Folsland Bolkesjø, Comparing the value of bioenergy in the heating and transport sectors of an electricity-intensive energy system in Norway, Energy Policy, 2015. 85: p. 386-396. http://dx.doi.org/10.1016/j.enpol.2015.06.021

Paper IV:

Dejene Assefa Hagos, Alemayehu Gebremedhin, and Torjus Folsland Bolkesjø, The prospects of bioenergy in the future energy system of Inland Norway, Under Review (Energy - The International Journal)

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Contents

1 INTRODUCTION

1.1 Background

In moving towards a low carbon economy, it is evident that the replacement of fossil fuels with an alternative RES is inevitable to ensure energy supply security and combat climate change. In recent decades, this has become a priority in major carbon-emitting countries. In 2012, following tremendous efforts in reducing emissions, global emissions increased by only 1.1%, much lower than the average annual increment in the previous decade (2.9%) [1]. However, despite all efforts, the renewable energy penetration rate is still very low. In 2012, the global RES share of total primary energy supply (PES) was only 13.2%; in the power sector specifically, 22% of the global electricity generation originated from RESs is forecast to reach 26% by 2020 [2]. Except for reservoir hydro and bioenergy, most RES are variable renewable energy (VRE) sources (run-of-river hydro, wind, solar, wave and tidal). The most commonly mentioned reasons for the low penetration of VRE sources, in addition to high investment costs, are intensive infrastructure requirements, their fluctuating characteristics, poor load following capability (or reserve capacity requirements) and high integration costs. Therefore, integration of high shares of VREs into existing energy systems requires a certain amounts of dispatchable power plant (e.g. gas-fired power plants and reservoir hydro power plants), ample transmission capacity and/or demand side management (DSM).

As part of the struggle against global warming, and in addition to its emission trading scheme launched in 2005, the EU set out a detailed legal framework for the decarbonisation of member states' energy mix - the so-called 20-20-20 target (2007): 20% increased energy efficiency compared with a business-as-usual-scenario; 20% overall RES share; and 20% emission cut compared to 1990 levels. Recently, the targets were stretched to 27-27-40 by 2030 [3]. The mid-term assessment shows promising progress towards achieving the 2020 targets [4]. Some EU member states have already achieved their targets, while most are progressing. The overall RES share ranges in-between 10% (Malta) and 49% (Sweden). In 2014, the overall EU RES share was 15.3% but the transport sector's is only 5.4%. Compared to the overall target, transport seems to be making very slow progress. Sweden is the only member state that has already reached its target for transport (16.7%). Non-economic factors, such as poor planning and administrative barriers, are some of the reasons offered for the low deployment rate of renewables, specifically in the power sector [4].

Within Nordic countries[1], the 2013 RES share of total PES was about 36%. Specifically, in the power sector, 83% of the electricity production is carbon neutral, 63% of which

[1]Nordic countries is a term used collectively for Sweden, Denmark, Norway, Finland and Iceland.

originates from renewable sources [5]. One of the world's largest electricity market, the well-functioning Nord Pool electricity market, is able to accommodate a large volume of VREs due to the large amounts of reservoir hydro power that can be easily regulated. The Nordic region has showed a coherent and uniform decoupling of GDP from energy-related carbon dioxide (CO_2) emissions for the last two decades, lowering the emission intensity in total PES to 30Mt CO_2/PJ [5]. Hydropower is the most highly explored RES in Norway and Sweden. More recently, effective implementation and monitoring of policy instruments like carbon taxation and subsidies have increased the penetration of bioenergy and wind substantially. Overall, increased use of RESs in Nordic countries substantially reduced the power supply emission factor to 59 g/kWh in 2013, a level the world would have reached by 2045 under the IEA's 2^{o}C scenario [5].

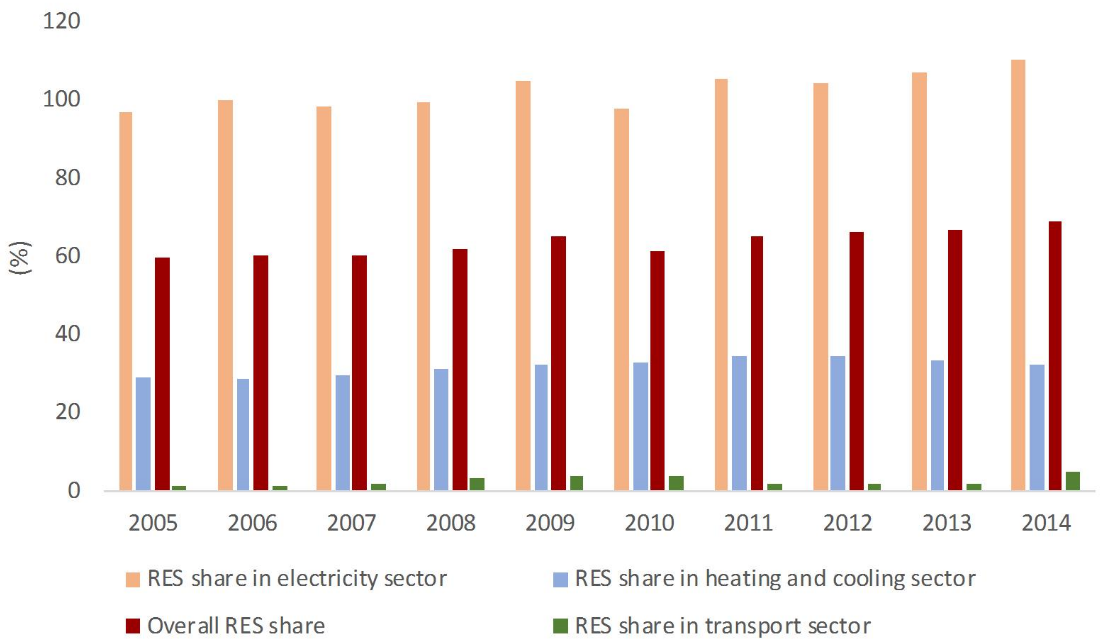

Figure 1: The share of RESs in the Norwegian energy system over the past years [6].

The Norwegian energy system is unique in that a hydro-dominated power sector and electricity-intensive end use devices make up an electrified system. The heating sector is 'monopolised' by electricity. This is in contrast to other Nordic countries, where thermal power plants and commercial district heating systems are heavily used. The transport sector is, by far, the main sector that serves as a fossil fuel 'sink' and contributes a large part of emissions in the energy sector [6]. Domestic energy use comprises 7% bioenergy, 51% electricity and 42% fossil fuel. The increase in RES share, by sector, over the past years is shown in Fig. 1. In 2014, the RES share was 109% in the electricity sector, 32% in the heating and cooling sector, and 4.8% in transport sectors, while the overall RES share is 69%. In line with European Economic Area (EEA) agreement, the long-term framework of EU renewable energy directives has motivated the Norwegian government to set a target of increasing the share of renewables from 60% in 2005 to 67.5%, a 14 TWh increased use of bioenergy and a 15-17 Mt CO_2 emission reduction by 2020 [7]. The overall RES share target is already achieved as of 2014. The RES share can be improved either by increasing renewable energy production or energy efficiency, or both. The Norway-Sweden common tradable green certificate (TGC) market, launched in January 2012 for a 26.4 TWh new electricity generation, is one key measure taken towards achieving the 2020 target [7]. However, the system strongly lacks flexibility or diversity: a single RES is used to generate power (hydro) and a single end-use device is used intensively (direct electric heater). The high dependency on hydropower makes the system extremely vulnerable to low precipitation. After 22 February 2010 in particular, where a record spot price of 1400 €/MWh was noted, reserve capacity - both power plant and transmission capacity, and power supply security (to ensure an uninterrupted and sufficient supply of electricity from all power sources) at large - became a major issue in Norway.

1.2 Inland energy system

This thesis is focused on a regional energy system study of Inland Norway. Of the nineteen regional counties in Norway, Oppland and Hedmark are the two located in the east of the country, with a total population of 383,960 living on a 52,590 km^2 land area; this constitutes Inland Norway [8]. The population density in urban settlements is 953 inhabitants/km^2, below the national average of 1,933 inhabitants/km^2 in urban settlements [8]. Following this, the share of dwellings by type stands as: detached houses (73%), row houses (7%), multi-dwelling buildings (8%), house with two dwellings (8%) and other buildings (4%) [9]. This makes this area a low heat density region and less suitable for connecting a large part of its households through the DH system.

In 2009, Inland's[2] total primary energy consumption (PEC) was 14.03 TWh: household 30%, service 18%, industry 16% and transport 36% [10]. Hydroelectricity and fossil fuels are the most highly used commodities in the energy system. Fuel use by type stands as 12% biomass, 47% electricity and 41% fossil fuel. More than 88% of the total fossil fuel is used for transport purposes and 12% for heating purpose. Energy consumption in individual households is the highest in the country, 26.6 MWh, primarily due to large floor area and high share of detached households. Emissions from Inland's energy sector are estimated to be 1.57 Mt CO_2. The transport sector accounts for 70% of the total CO_2 emissions, while the remaining 30% originates from heating sectors.

Electricity generation is 100% renewable and originates from hydropower. In 2009,

[2]In this thesis, wherever Inland is stated, the term refers to the Inland Norway of Oppland and Hedmark counties

the total installed capacity was 2075 MW, 985 MW of which is reservoir hydro and 1,090 MW run-of-river plant. In the same year, 9.28 TWh of electricity was generated, 5.88 TWh of which was used for domestic consumption and the remaining 3.4 TWh exported to nearby counties. The hydropower potential is highly explored. Of the remaining potential, only 1.65 TWh or 397 MW is found to be feasible for small-scale development.

Wind power development in the region is under way [11]. So far, the Norwegian water resource and energy directorate (NVE) has approved 307 MW/0.92 TWh onshore wind power projects [11]. Solar energy use in Inland is unknown. Forest based resources are the main biomass source in Inland Norway. More than 50% of Norwegian forest resource is located in Inland and constitutes more than 43% of the countrys total annual harvest [12].

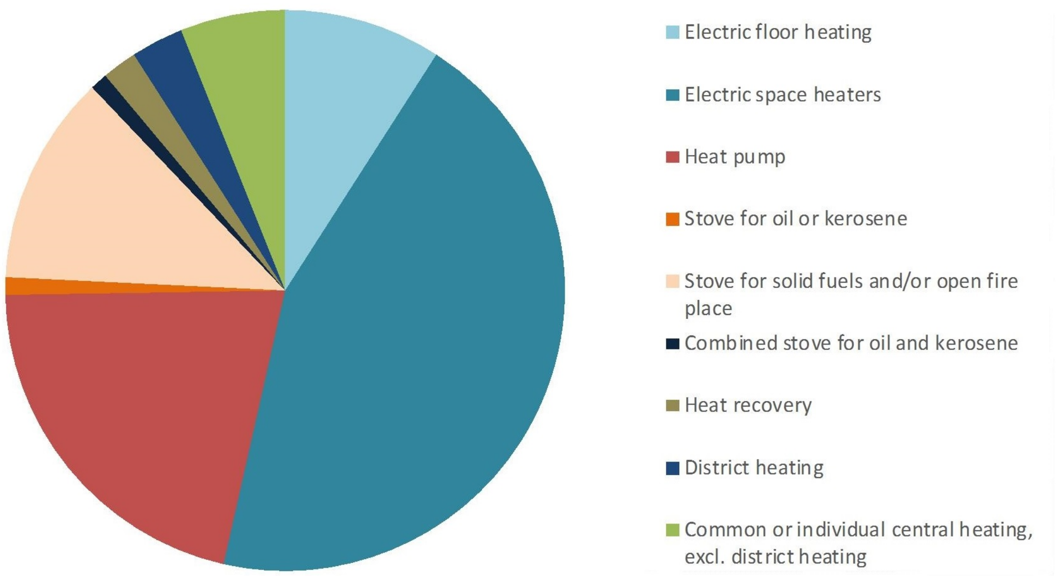

Figure 2: Households by main heating source [10].

Looking at the technology mix, direct electric heaters, wood stoves, and central electric and oil boilers are the main heating technologies used in the household and service sectors. The share of households by main heating source is shown in Fig. 2. More than 94% of households had direct electric heaters, 55% of which used it as a main heating source. The penetration of heat pumps in the household sector is around 18.5%; the share increases to 33% for detached households [10]. The existing energy system appears to be segregated, with not much integration between the heating, electricity and transport sectors.

Even though Inland is a low heat density region, small-scale DH could be used in inner city residential buildings, services and industries. So far, 12 small-scale district heating plants with annual production of 0.24 TWh are currently in operation in Inland, most of them new [13]. Following the government ambition for increased use of bioenergy and RES share, and emission reduction, the NVE has approved more than twenty new and expansion plants, with an estimated annual production of 1 TWh [11]. Most of these plants are composed of wood chip boiler for base and bulk load (70%), electric boiler (15%) and natural gas boiler (15%) for peak load.

In the Nord pool power market, the Norwegian bidding area is divided into five regions: East Norway (NO1), South-west Norway (NO2), Middle Norway (NO3), North Norway (NO4) and West Norway (NO5). This means that all regions under a given bidding area will have the same electricity price. Inland is located in eastern Norway and, therefore, part of bidding area 1 (NO1).

1.3 Objective

International obligations for CO_2 emission reduction and increased RESs share, as well as local energy supply security concerns, have motivated the Norwegian government to re-evaluate national energy policy at all levels and persuade experts in the field to embark on research related to sustainable energy generation and utilisation.

To this end, to identify clearly the missing points in the existing energy system and those anticipated to create a flexible and more integrated energy system, a system perspective analysis is vital. It should exploit synergy effects between energy sectors, identify useful policy instruments in light of national energy policy objectives and assort RESs and energy conversion technologies in the energy system. The reasons are: firstly, to identify the policy gaps, if any; secondly, to impact policy makers with those missed opportunities.

Therefore, the main objective of this thesis is to make a techno-economic assessment of renewable energy technologies from an energy system perspective and to explore possibilities for increased use and integration of RESs into the future energy system of Inland Norway.

In light of the main objective, the sub-objectives of the thesis which aim to answer specific research questions and identify policy instruments are listed below.

- To identify the most valuable sector for increased bioenergy use - electricity, heating, or transport sectors.
- To investigate technical and economic aspects of different alternatives for increased RES shares
- To investigate the contribution of wind energy to power supply security

- To evaluate, in light of the energy policy objectives, the techno-economic benefits of the replacement of direct electric heaters with flexible technologies and of conventional fleets with green fleet technologies

The study will be limited to Inland Norway, due mainly to the following reasons. (1) To generate regional knowledge on the integration and use of RESs in collaboration with local energy suppliers. (2) In light of national energy policy objectives, to assist the Inland Energy Agency (which is the first of its kind in Norway) in the design of regional policy instruments and energy targets. (3) A transition to a renewable-based energy system needs models and analyses with a fine spatial and temporal resolution. (4) Though the energy service structure is the same in all regions, the fact that high household energy consumption and substantial forest based biomass resource availability are additional motivations for a regional energy system study.

1.4 Thesis outline

The thesis is organised into seven sections. The first section provides brief background information about the research field, defines problems, provides brief information about the study region and its current energy system, provides the main and sub-objectives of the study, presents the thesis outline and discuss prior related works. Section 2 presents the state of art heating technologies, energy plants and biorefinery technologies, as well as an overview of their potential and challenges in the energy system. Section 3 briefly discusses the methodology followed, presents the modelling tools used for the analysis based on structure, purpose and function. Section 4 discusses results and findings obtained from each article; results are presented in chronological order of the articles and by addressing the research questions. Section 5 presents concluding remarks, followed by limitations of the study in section 6 and future research suggestions in section 7.

1.5 Related work

To date, several studies have analysed the contribution of different heating technologies to emission reduction and fuel saving. Thyholt et al. [14] concluded that low-energy buildings using individual electric heating in Norway have lower CO_2 emissions than DH connected standard buildings. Lund et al. [15] demonstrated that from the overall system perspective, the combination of district heating and individual heat pumps has lower total fuel consumption and CO_2 emissions in existing building stocks. Möller et al. [16] concluded expanding the district heating network in inner cities and towns and individual heat pumps in low heat density areas as the best solutions to reduce emissions, fuel consumption and system cost and to increase the RES share. Joelsson et al. [17] concluded that replacing direct electric heating with a biomass-based DH system reduced primary energy use, CO_2 emissions and societal cost substantially, irrespective of building size and standard. Östersund et al. [18] looked into the impact of investment subsidies and marketing campaigns for the replacement of direct electric heating systems with DH. Fiedler et al. [19] demonstrated that using a hybrid pellet boiler and a solar thermal system instead of a standalone pellet boiler would reduce the CO emissions by half. Most of the studies are focused primarily on a specific sector, however, and therefore they do not provide the effect on the whole energy system.

Integrating a large amount of VRE into the traditional power system requires an integrated, technology-rich and flexible energy system, and increased penetration of VRE without flexibility measures would reduce their market value [20]. Heat pumps, electric boilers (EBs), electric vehicles (EVs) and hydrogen fuel cell vehicles (HFCVs) are among the demand side management (DSM) that could facilitate the integration of VRE. Blarke [21] demonstrated that compression heat pumps are a better option than EBs for cost-effective integration of distributed cogeneration and VRE. Furthermore, Meibom et al. [22] showed that in addition to the fuel saving benefits, EBs and HP s could increase the market value of wind power in terms of reducing low price hours, curtailment and the regulating price in the northern European power system. Brian et al. [23] analysed the Danish energy system for wind power integration and concluded that large-scale HPs and BEVs are the most fuel-efficient and least expensive technologies for VRE integration. This study was based on a technical energy system study without the influence of the external electricity market, however. In addition to oil saving benefits, EVs could be used as DSM to integrate VRE. Finne et al. [24] examined the use of the EV charging cycle as DSM to achieve financial savings, replacing thermal generation with renewable production, and peak load shaving. Kjellsson et al. [25, 26] analysed a hybrid solar-ground source heat pump system and suggested using solar thermal for domestic hot water production in the summer and recharging the borehole in the winter for an optimal operation strategy. Furthermore, Wang et al. [27] showed that the performance of a hybrid solar-ground source heat pump depends largely on storage size, collector area and solar radiation intensity.

The optimal use of biomass from the cost and environmental perspectives has been addressed in prior studies. Azar et al. [28] and Gielen et al. [29] modelled the global energy system to suggest the most valuable sector for bioenergy use, employing different models from a cost perspective. Azar et al. concluded that it is more cost effective to use biomass for heat as a substitute for fossil fuels, while Gielen et al. concluded that it is more cost effective to use it for transportation than for heating. The discrepancy between the two results was investigated further by Grahn et al. [30] and showed that at a low carbon tax rate (below $50-100/tonne), biomass is a cost-effective solution for heating. At a high carbon tax rate (above $100/tonne), however, and contrary to Azar et al. who used carbon-free hydrogen sources as an alternative transport fuel, Gielen et al. found that it is cost effective to use biomass for transport. The basic difference is the assumption of the availability of an alternative source of transport - a carbon-free hydrogen. Steubing et al. [31] modelled the EU-27 energy system and concluded that from an environmental perspective, the optimal bioenergy assortments depend largely on the marginal substitutes (type and volume of fossil fuels) and efficiencies of bioenergy technologies. Wahlund et al. [32] concluded that from a Swedish perspective on CO_2 emission reduction, it is more cost effective to use biomass for heating as a substitute for coal than as a transport fuel. Gustavsson et al. [33] compared the benefits, from a Swedish perspective, of using biomass for CO_2 mitigation and oil use reduction. If the objective is CO_2 mitigation, using biomass for heating is more efficient than using it as a transport fuel. The reverse is true if oil use reduction is the aim.

The benefits of bioenergy and other conventional technologies in local DH systems for cost-effective reduction of global CO_2 emissions were studied in [34]. It was concluded that biomass gasification-based CHP and biorefinery would lead to a greater reduction in the global CO_2 emissions than bioheat boilers. Studies showed that deployment of DH in high heat density areas and individual heat pumps in detached or low heat density areas is a cost-effective solution for decarbonisation of the EU-27 energy system and to achieve its emission target by 2050 [35, 36]. The feasibility of various DH integrated, renewable synthetic fuel pathways for integration of VRE and replacement of conventional fuels in a 100% renewable energy system was studied in [37].

However, all of the aforementioned studies and others in the literature focused on the replacement of fossil-fuel based heating systems with renewable sources or integration of VREs into a thermal dominated power system. To the best of our knowledge, no prior study has examined the replacement of direct electric heating systems with flexible technologies in a green electricity-intensive energy system to increase the penetration of RESs from an overall system perspective.

2 TECHNOLOGIES

As clearly stated in the introduction and objective sections, integrating alternative technologies and RESs is the first step towards answering the research questions. In this section, the selected state of art technologies and their contributions to the integration of RESs are presented.

2.1 Heating technologies

2.1.1 Direct heating

As the name - direct - indicates, heat is generated at the point of demand and function as a point source without being transported through pipeline or duct. The heat generated is transferred to the room air mainly through convection heat transfer (air motion) mechanisms. The effectiveness of attaining the set point comfort temperature relies on the even distribution of the point source or heating device in the vicinity.

Direct heating technologies include electric heaters, wood stoves, air to air HPs and water to air HPs. Typically, heating capacity for air to air HP ranges from 3-8 kW and 4-8 kW for wood stoves [38]. A single air to air HP unit normally covers 60%-80% of space heating demand, while a wood stove covers 20%-60% [38]. The remaining spacing heating and hot water heating demand would be supplemented by other heat sources, which would normally be electrical heaters or additional units of each technology. The coefficient of performance (COP), defined as heat output divided by input power, depends largely on the heat source (ambient air) temperature. In cold areas like Norway, air to air HP tends to show a lower COP. Electric heating is the only source that could cover both space and hot water heating demand (100%) or possibly could be supplemented by HP and wood stove to incorporate some degree of flexibility. Typically, capacity electric heating ranges from 5 kW for a single family building to 400 kW for an apartment complex.

2.1.2 Waterborne heating

As opposed to direct heating, waterborne heating has a heat distribution system where a secondary heat transfer fluid (water) is used to transfer the source heat to the room air. Depending on the construction, the heat distribution could be floor heating, fan convector, radiators or a ceiling heating system. Heat is transferred to the room air mainly using a convection (typically 40%) and radiation (typically 60%) heat transfer mechanism [39]. A waterborne heating system offers the possibility of switching between heat sources, easy to generate centrally, and transporting heat energy using small pipes over a wide area instead of huge air ducts (especially in large buildings) as is the case in direct heating. This is primarily due to the huge density difference between water and air, i.e. water is approximately 800 times denser than air at standard ambient temperature (25^{o}C).

Waterborne or hydronic heating technologies include boilers, water to water HPs, air to water HPs and solar collectors. All boilers and HPs could cover both spacing heating and hot water heating demand, while solar collectors cover all hot water heating demand. Depending on the configuration, the boiler could be manually fired on wood logs or an automatic fuel feeder and fired on wood pellets or wood chips. Automatic boilers can be regulated below 30%-100% of full capacity without compromising efficiency and violating emission requirements [38]. Typical capacities for automatic boilers range from 8 kW for a single family building to 500 kW for an apartment complex, while manual boilers are available from few kW to 100 kW. Space requirement is the limiting factor for a biomass boiler and storage. Usually wood pellets are used for a single family building, while either wood pellet or wood chip could be used for a large building.

Typical capacity for air-to-water HP is from 4 kW to several hundred kW for large buildings, and could supply both space and hot water heating demand. The variable speed compressor enables the regulation of the capacity as low as 20% of the rated capacity [38]. The COP depends largely on the heat source (ambient air) temperature, and the higher, the better.

By the end of 2011, more than 85% of installed solar thermal systems worldwide were used for domestic hot water preparation in a single-family house [40]. This share is reduced to 65% in Europe. Unglazed and glazed flat plate and evacuated tube collectors are the main collector technologies being used. The auxiliary heating could be either an electric or gas fired conventional heating system. More than 63% are evacuated tube, 28% glazed and 9% unglazed flat plate collectors [40]. The typical collector size for a single family is 4-6 m^2 with a daily hot water storage capacity of 300 L. The output largely depends on solar irradiance availability and the actual operating temperature relative to ambient temperature.

2.2 Energy plants

2.2.1 District heating

District heating is an integrated system of centralised heat generation and distribution through a pipeline network, with the purpose of supplying heat to various end users for space heating, domestic hot water and industrial processes heating. The heat source in the central plant could be combined heat and power production (CHP), surplus heat from industry, waste incineration, heat pumps, solar thermal and boilers (electric, biomass, natural gas or oil). District heating in Norway is at the infant stage. In 2009, the share of DH in total heat demand accounted for 6% in Norway, 55% in Sweden, 47% in Denmark, 49% in Finland and 92% in Iceland [41].

DH is quite an important heating concept in that it could increase energy efficiency and create a potential space for integration of more RES into the existing energy system. It is also considered a key concept in creating future smart energy systems [42, 43, 15]. The supply temperature of most existing DH systems is around 100^{o}C, making it suitable for the use of high-temperature heat sources. However, extensive research has been done recently on a 4th generation DH concept aiming to reduce the temperature of the DH network [44, 45, 46]. The concept would help to connect low-heat demand or energy-efficient buildings in the future and to make use of low temperature heat sources as well [43].

In terms of CHP use in DH, Denmark is a success story. Decentralised CHP, along with heat pumps and heat storage in DH, are the major sources of supply side flexibility in the Danish energy system and contribute to a higher wind energy penetration level than any other country. In 2013, more than 32.5% of Danish domestic electricity supply came from wind [47]. During low wind availability, CHP, HPs and thermal storage function to increase electricity production and meet both electricity and heat demands, and vice versa when there is high wind availability. Lund et al. [48] showed that coupling of CHP along with heat pumps in Denmark is feasible for balancing power supply and could increase wind power integration to as much as 40% of the electricity supply. In recent work, large-scale heat pumps in DH using sea water as a heat source were found to play a key role in shaping the future energy system of Denmark [49].

2.2.2 Biorefinery

In this thesis, a gasification based biorefinery plant producing second generation biofuel, heat and electricity is considered. Biomass gasification is a high-temperature thermal conversion process. As such, gasification increases the heat density of the feed-in solid biomass and converts it into syngas. Subsequently, the latter could be used for many purposes - heat, electricity and biofuel production. It is an efficient process with typical cold gas efficiency greater than 90%. Gasification is the heart of all second generation biorefineries. The point of departure is chemical synthesis where the syngas is converted into different biofuels, depending on the catalysts used (FT-biodiesel, DME, methanol).

Biomass (lignocellulose) gasification based second generation biofuel production is, at its best, on the verge of commercialisation. In this study, Fischer-tropsch (FT) biodiesel and dimethyl ether (DME) are the selected pathways for the sake of process data availability, development stage and feed in biomass type. Biodiesel and DME have been considered the most promising and viable synthetic fuels as a substitute for diesel in conventional vehicles, with a marginal cost for modification to the fuel injection system. The biochemical pathway (fermentation) using lignocellulosic biomass (except for herbaceous resources) is still at an experimental stage or, at its best at a pilot scale, and not considered here. In the production chain of the DME pathway, DME could be produced by dehydration of methanol with marginal energy consumption. However, the marginal energy consumption of the dehydration process would be offset by the comparably high efficiency of diesel engines as compared to petrol, resulting in a fairly similar overall efficiency.

In this study, as shown in Fig. 3, a hydrogenated gasification based biorefinery plant producing electricity, heat and biofuel is considered. The heat recovery steam generator (HRSG) supplies steam to the turbine and to the gasifier (steam is used as an oxidising agent to boost the hydrogen content of the syngas). Electrolysers are integrated into the system for further hydrogenation, where the syngas' H_2 content is adjusted for optimal fuel synthesis and, hence, to limit biomass consumption. The hydrogenation process down to HRSG helps to regulate the cooler syngas hydrogen content; in turn, this helps to reduce the feed-in biomass consumption which would otherwise be used without hydrogenation. The process is adapted from prior studies [50, 51, 37].

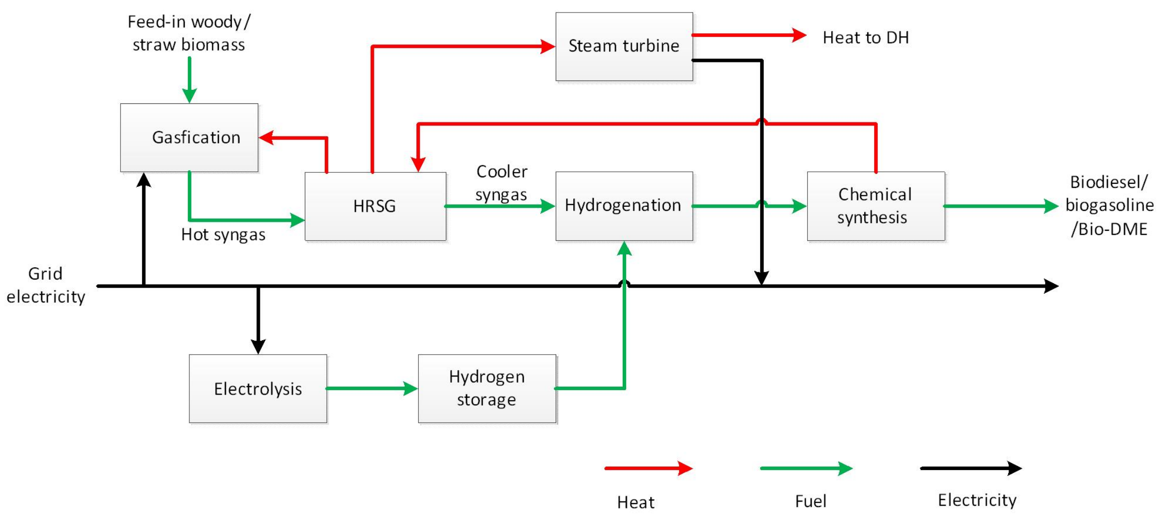

Figure 3: District heating integrated biorefinery system, working components, and energy flow diagram

The ultimate role of the electrolyser is to limit biomass consumption and serve as a relocation technology for utilisation of surplus electricity. It not only converts the surplus electricity into a liquid fuel but also provides flexibility in the system - heat to DH through the HRSG unit and hydrogen to chemical synthesis. Further, pure oxygen produced in the electrolyser would also be used in the gasification process to avoid the risk of NOx emissions, instead of using ambient air as in a conventional gasification process. Detailed techno-economic feasibility studies have been done on possible synthetic fuel production pathways in [51, 37], while a review of the Danish experience and a DME feasibility study for a city in Sweden can be found in [50, 52].

2.2.3 Electrolysers

Electrolysers are a relocation technology in a flexible energy system, whereby excess electricity could be converted into hydrogen and stored for later use in fuel cells or for production of synthetic fuels. That process is called electrolysis. The higher heating value (HHV) of hydrogen is 142 MJ/kg, approximately three times that of hydrocarbon fuels. However, due its lower density, large-scale storage becomes very expensive and hampers its competitiveness and deployment rate.

Polymer electrolyte membrane (PEM), alkaline and solid-oxide electrolysis cell (SOEC) electrolysers are known to be suitable and applicable in energy systems [53, 54]. PEM and alkaline are the most developed and commercially available technologies for decentralised small-scale applications, but SOEC is still under development and considered a promising technology to integrate VREs in future energy systems, due to its large scale and high temperature operation [54]. The state of art characteristics of PEM are moderate operating temperature (50-70^{o}C), unit module capacity (0.15 MW) and system efficiency (54%), and it has a fast regulation ability (0%-100% power in less than a few seconds). Compared to PEM, alkaline electrolysers offer a wider operating temperature range (60-80^{o}C), unit module capacity (3.4 MW), system efficiency 67% and fast regulation ability. The first commercial SOEC is expected to appear from 2020 onwards. The potential operational characteristics are high operating temperature (800^{o}C), higher unit module capacity (0.5-50 MW), approximate system efficiency of 76.8% and fast regulation ability [55].

2.3 Green fleet technologies

2.3.1 Biofuel standard vehicles

In this study, biofuel standard vehicles are conventional vehicles with a modified fuel injection system for biofuel blends (2-20%). Fuel flexible vehicles are those specifically designed to run on biofuels and could be blended at any proportion (0-100%). The assumption is that, in the short term, standard vehicles would continue their dominance of a conventional fleet. Therefore, modelling biofuel standard vehicles with 2%-20% ratio (by energy) is found to be more reasonable in this study. Biodiesel blends in the range of 2%-20% can be used in most diesel engines with little or no modification. Experimental studies show that DME/diesel blending from 10%-30% could be possible without a significant impact on engine performance [56, 57].

2.3.2 Electric vehicles

The existence of EVs in a future energy system has multiple benefits, including emission reduction, energy supply security, energy efficiency, integration of VREs and creation of a flexible energy system at large. In terms of EVs penetration, Norway is a success story. As of 2014, its EV accounted for 6% of global stock and approximately 13% of global market share [58]. Tax exemption, access to bus lanes and free parking are the main policy instruments behind the increased deployment rate [59].

In [60], it was concluded that battery EVs have lower socio-economic costs than other green fleet and conventional technologies, and are also less vulnerable to fluctuating energy prices. However, for a longer driving range and high penetration, swift development of storage batteries in terms of cost reduction and longer service life are crucial factors.

Intelligent charging/discharging EVs facilitate wind power integration and reduce the need for load following or dispatchable power plants, though at the expense of increased system cost [61, 62]. Sioshansi et al. [63] showed that plug-in hybrid electric vehicles (PHEVs) could provide ancillary services in power system and reduce the need to reserve capacity requirement.

Compared to conventional vehicles running on diesel/gasoline, one might assume that deployment of EVs would reduce CO_2 emission substantially. However, the benefits are largely dependent on the source of electricity, electricity production mix and conversion efficiency. In a renewable electricity dominated system, however, EV emission reduction is substantial [61]. This is because emissions displaced from conventional fleet are higher than those generated from electricity production used in EVs. The reverse is found to be true in the case of conventional power plants, where the benefit is more from electric generators than direct displacement of conventional fleets [62]. In addition, due to the replacement of conventional fleet, EVs could contribute to increased energy supply security, especially for oil importing countries.

2.3.3 Hydrogen fuel cell vehicles

Hydrogen fuel cell vehicles (HFCVs) are powered by hydrogen stored on board. The fuel cell system converts hydrogen into electricity and drives the electric motor. The source of hydrogen could be electricity (electrolysis) or other conventional fuels. The typical storage capacity is around 4 kg and normally covers a driving range of 450 km, which is, on average, three times that of battery EV (BEV). HFCVs are not as popular as EVs primarily due to high vehicle capital cost and limitations on hydrogen supply and distribution infrastructures. The future deployment rate is heavily dependent on the flexibility of electrolysers, cost effective and efficient storage and distribution system, and development of efficient fuel cells [60].

HFCVs are less efficient and costlier than BEVs but, in terms of integrating VRE, are found to be a better alternative than BEVs as demonstrated in a Danish 100% renewable energy system analysis. This is primarily due to the fact that the high electricity demand for hydrogen production opens up an opportunity to reduce excess electricity production at times of low demand [60].

Considering the complexity of well-to-wheel (WTW) analysis, it is difficult to make a clear distinction on HFCV energy saving and emission reduction potential in relation to conventional vehicles, several studies have showed the potential benefits of HFCVs. A detailed WTW study showed that, due to their higher vehicle efficiency, HFCVs could reduce petroleum use, GHG emissions and pollutants substantially, even when the hydrogen source is fossil fuel [64]. A similar WTW study in Norway suggested that HFCVs would have a significant advantage over conventional vehicles if the hydrogen is from RESs [65]. Hydrogen produced from US average electricity mix and natural gas based refuelling stations showed increased energy use and emissions over conventional gasoline vehicles [66]. This is evidence that fuel source pathways need to be examined very carefully to draw specific conclusions.

3 METHODOLOGY

This section presents the details of the theoretical framework of the study, modelling tools selection based on purpose and structure, model development and optimisation criteria used in the models.

3.1 Theoretical framework

Integration of more RESs into the traditional energy system requires, at least, the introduction of energy carrier switching, creating synergy effects between energy sectors, energy conservation and behavioural changes on energy consumption magnitude and pattern. The respective responses would be reflected by altering the load profiles.

Following the intensive use of electric heating, heating and electricity demand profiles are found to be in phase and both are peaking during winter periods where the precipitation level is very low. In this particular case, energy carrier switching or the replacement of direct electric heating with a waterborne heating system would mean a seasonal peak load shaving mechanism and make the end-use energy conversion devices a deferrable or shiftable load. In a nutshell, peak load shaving plus shiftable loads could introduce fully functional demand side flexibility into the system. The socio-economic benefits would be equivalent to reducing or avoiding the construction of new power plants and transmission lines, a flatter electricity demand curve, hence a stable electricity price at large.

The first step forward is to replace direct electric heating systems with waterborne ones which, in turn, could create a 'vacant space' in the energy system for competition between heat sources and integration of new RESs.

To introduce and analyse the aforementioned measures into the energy network, firstly, a reference system which could possibly frame the main research questions was required to be calibrated. Then, a cascaded scenario based approach tailored to a predetermined, comprehensive solution perceived to incorporate flexibility in heating and transport sectors was formulated (labelled as alternative systems). It is a radical technological change. Fig. 4 shows the detailed work flow structure of the study. The alternative systems reflect the on-going activities towards energy policy objectives and those perceived to have been missed or received less attention. The reasons are: firstly, to identify the policy gaps - if any; secondly, to impact policy makers with those missed opportunities. For example, virgin wood biomass has been intensively allocated in district heating for bioheat boilers with quite small or no heat pumps at all. Biomass is a unique and multifunctional resource that could be used in all sectors - electricity, heating and transport.

The regeneration and utilisation rate determines its renewability. If the regeneration rate is higher than the utilisation rate, that particular biomass is a renewable resource - and vice versa. Therefore, controlled use of this multi-functional resource ensures its sustainability. Based on the solar thermal techno-economic feasibility study results in Paper I, solar thermal is also included in the alternative systems formulation.

The optimisation framework in long-term planning or macro-models is characterised by low temporal resolution, while it is a high temporal resolution for operation strategy or micro-models. The long-term evolution of an energy system requires investment and operation cost optimisation; hence, it is a fully economic model. The combined use short-term operation strategy model (Papers II and III) and long-term planning model (Paper IV) have been practised to answer the research questions fully. The reason is that alternative scenarios are draft systems that could be optimised for operational strategy with the highest temporal resolution. Whereas the long-term evolution of the energy system is driven by demand, technological development and energy price development. The outcome of the models would be compared based on technology mix and production levels to draw a general conclusion that leads to a solid answer to the research questions and objective of the study.

Economic models, driven by cost, hardly capture and reveal radical technological changes in an alternative system. Therefore, a unique optimisation framework was drafted - to separate technical and economic optimisation. Firstly, the comprehensively drafted two alternative heating systems operational strategy were optimised in Paper II. The optimisation had been made in such a way that, firstly, the most technically efficient alternative heating system is identified. Then in Paper III, a cascaded alternative transport system was drafted and optimised from business economic perspectives to note down how the different costs, taxes and electricity markets distort the efficiency of the energy system.

3.2 Renewable energy resource survey

It is essential to identify the available RES potential that could be harnessed or explored within energy planning. The regional RES potential of wind, hydro and bioenergy has been determined through a literature survey and raw data review, as discussed thoroughly in Papers II-IV, and set as an upper activity bound in all models. However, to the best of our knowledge, no solar energy use study exists at all. Therefore, the regional solar energy potential and a solar thermal techno-economic feasibility study have been carried out in Paper I. The solar energy potential was estimated for a solar thermal application, as solar photovoltaic has insignificant importance in a 100% hydro dominated renewable electricity sector. In Paper I, two types of solar water heating

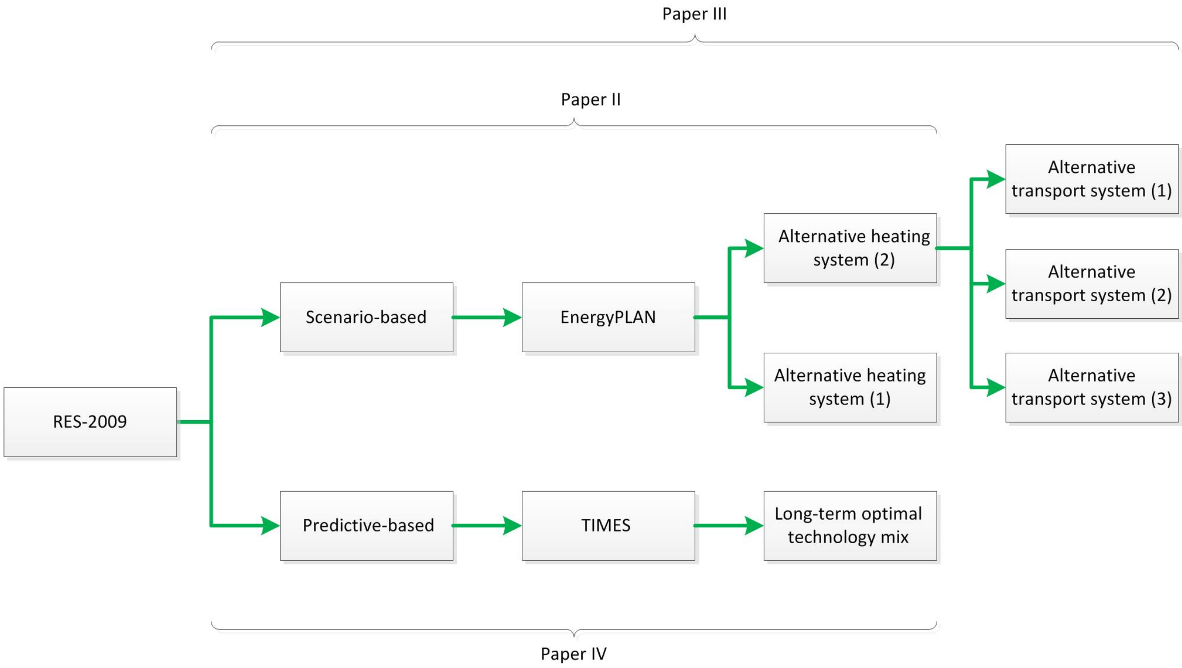

Figure 4: Theoretical framework of the study. RES-2009 refers to the reference system for 2009. The scenario-based approach (all investments are exogenous) optimises only the operation, while the predictive-based approach (all investments are endogenous) optimises both the investments and the operation. Although Paper I is not shown here, it has been discussed briefly in section 3.2 and used in the alternative systems formulation in Paper II and Paper III, as well as Paper IV.

systems - evacuated tube and flat plate collectors - were modelled and simulated on an hourly time resolution. For a given daily storage size, the optimal collector area and its corresponding breakeven capital cost, monthly energy saving, net present value (NPV) and payback period were determined. It was concluded that solar thermal or solar water heating (SWH) is feasible but not attractive. The main impact parameter is also found to be the electricity price. Moreover, for a residential application, evacuated tube SWH is found to be a priority over flat plate SWH, for performance and cost reasons. As shown in Fig. 5, evacuated tube SWH could cover as much as 62% of typical residential hot water demand at an optimal collector area of 4.67 m^2, whereas the glazed flat plate covers 48% at an optimal collector area of 4.67 m^2. The main contribution of Paper I, apart from its local importance and being used as an input for Papers II-IV, extends to the northern hemisphere, specifically Nordic areas. This is because, to the best of our knowledge, there were no prior study which pinpointed the trade-off between specific investment cost and energy saving of these two types of solar collectors; each has a unique characteristic in different weather conditions.

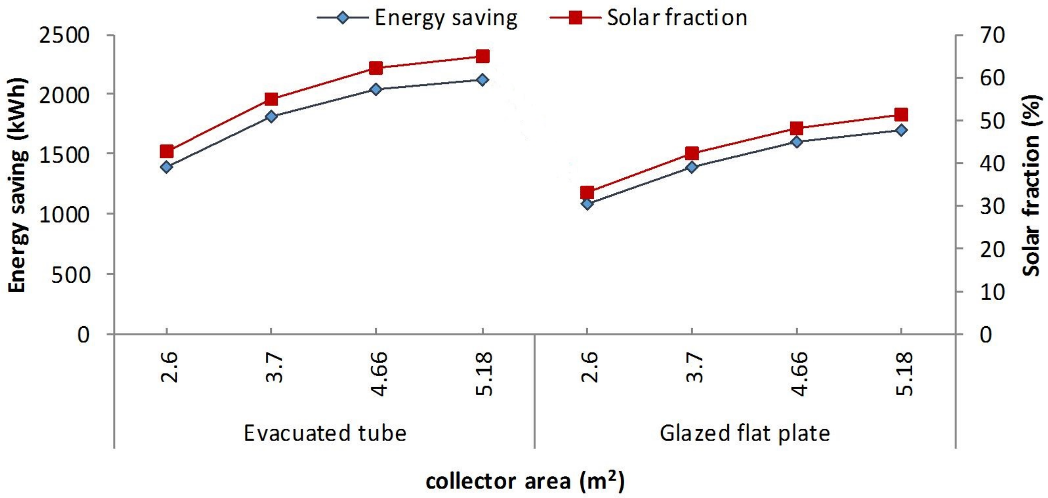

Figure 5: Annual electric energy saving and solar fraction for a series of collector area and a fixed storage capacity of 250 L. The results are taken from Paper I, but additional simulation for a similar collector area has been done to illustrate better the optimal collector area of both collector types.

3.3 Energy system analysis tool selection

In energy planning, several of the objectives might be self-contradicting, e.g. least-cost energy supply, increasing RES share, system efficiency, emission reductions and energy supply security. To address specific targets, appropriate tool selection is the critical step in energy modelling. As part of the research design, two system analysis tools that suit the ultimate objectives of this thesis have been selected: EnergyPLAN (operation strategy optimiser) and TIMES (long-term energy planner).

The most developed and extensively used modelling tools fall into two categories either high temporal resolution (typically an hour) and short term (typically a year) or low temporal resolution (typically a year) and long term (typically 20 to 30 years). However, to capture the demand and supply dynamics of an energy system, specifically for VREs, both fine resolution and long-term model development are crucial to avoid overestimation of investments. To this end, several hybrid optimisation frameworks have been developed to address specific problems, using short-term and long-term models. These include PERSEUS-CERT and MATLAB [67], LEAP and EnergyPLAN [68], TIMES and MATLAB [69], and TIMES and EnergyPLAN [70]. Given the objective and theoretical framework of the study, instead of using a hybrid framework, the results of the two models (EnergyPLAN and TIMES) were compared and used to answer the main research questions.

3.3.1 EnergyPLAN system analysis tool

The EnergyPLAN model has been developed and maintained by the Department of Development and Planning at Aalborg University in Denmark. It is a deterministic input/output and an hourly simulation model. The model is aggregated in its system description and covers the whole energy sector (heating, electricity and transport) [71]. EnergyPLAN optimises the operation of a given system under different technical and economic optimisation regulations. As such, under the technical optimisation regulation, it minimises the total fuel consumption of the entire energy system. Similarly, under the economic optimisation regulation, the model minimises the socio-or business economic costs of the entire energy system.

EnergyPLAN offers a detailed representation of the whole sector, a unique optimisation framework and high time resolution (hourly). It is, extensively used for integration of RESs at all levels and size that are published in various peer reviewed journals, requires short training time and is freely accessible with ample documentation; hence, it functions, per se, as a useful database source.

EnergyPLAN has a unique optimisation framework. The technical optimisation minimises the total fuel consumption or performance of the energy system and determine the corresponding socio-economic costs without any interference by market infrastructures like the Nordpool electricity market. Then one has the opportunity to note down the impact of market infrastructures by running business-economic optimisation to see how close the existing energy system is to a technically optimal system. This is an important input for policy instrument design in the decision-making process. The model description of both optimisation regulations and their dispatch merit orders, based on the EnergyPLAN documentation [71], is given below.

Technical optimisation regulation strategy I (balancing the heat demand): in this strategy, all heat-producing units are set to do so according to heat demand. Inherently, the model is set to prioritise the units in the order of solar thermal, industrial waste heat, combined heat and power (CHP), heat pumps and peak load boilers.

Technical optimisation regulation strategy II (balancing both heat and electricity demands): all heat-producing units are prioritised in the same way as regulation I, but export of electricity is minimised using heat pumps in CHP plants. Heat pumps use excess electricity and dispatch more heat, whereby the heat and electricity production from CHP plant is minimised. In such a way, the model increases electricity consumption and decreases electricity production at the same time. Basically, the regulations focus on CHP unit operation. In a system without CHP units, all heat-producing units follow heat demand and all power-producing plants follow electricity demand if either of the regulations is chosen.

Economic optimisation regulation strategy: the system interacts fully with an external market region and tends to moderate technical regulations further. As such, the system exports electricity when market prices are higher than marginal production costs, and vice versa.

There are a number of studies based on EnergyPLAN. These include: a radical technology change in the energy mix towards a 100% renewable energy system for Macedonia [72], Ireland [73], Denmark [74, 75, 76], China [77] and Frederikshavn - a city in Denmark [78]; and analysing the key stages in a radical technological change towards a 100% renewable energy system and its contribution for job creation using Ireland as a case study [79].

3.3.2 TIMES system analysis tool

The Integrated MARKAL-EFOM (Market Allocation Energy Flow Optimisation Model) System or TIMES is a generic energy system model generator and optimisation tool developed and maintained by the Energy Technology System Analysis Programme (ETSAP), an implementing agreement of the International Energy Agency (IEA). TIMES is comprised of the entire energy system, i.e. electricity, heat and transport sectors [80]. It is a perfect foresight, partial equilibrium linear programming, bottom-up, technology rich and demand driven optimisation model. As opposed to stochastic models, perfect foresight models like TIMES do not capture forecast errors on highly fluctuating resources like wind and solar. The objective function minimises the total discounted system cost for the whole modelling period and maximises the social surplus of the system at different temporal time resolution. Therefore, TIMES is suitable for long-term energy planning, from primary energy extraction to final energy consumption, and to analyse the impact of market measures and energy policies on technology mix, fuel mix, emissions and cost to energy systems.

The time resolution in TIMES is quite flexible, but not continuous as in other hourly optimisation models, e.g. EnergyPLAN. The entire modelling horizon can be divided into several periods of different length, the minimum being a year. A year (an annual time slice) is then further divided into three parent time slices: seasonal, weekly and day-night level. This allows the modeller to identify and model the critical time periods in each year, so as to capture the supply and demand dynamics of the energy system. The modelling of time-dependent variables (e.g. process efficiency, availability, costs and financial parameters), several input-output processes and different economic and technical lifetimes of a process are possible in TIMES. These makes the model flexible and suitable for detailed representation of complex systems.

TIMES has been used extensively for long-term energy planning at regional and national levels. Examples include: analysing the optimal renewable energy production mix in Norway's future energy demand [81]; assessing EU-renewable targets and national targets in Spain [82]; studying cost-effective electricity sector decarbonisation opportunities in Portugal by 2050 [83]; modelling buildings' decarbonisation in China [84]; modelling decentralised heat supply [85]; modelling household energy use behaviour and heterogeneity [86]; impact of carbon capture and storage on the electricity mix and energy system costs [87]; long-term development of the global energy system towards 100% RESs [88]; and assessing EU 2^{o}C climate target possibilities [89].

3.4 Model development in EnergyPLAN

The EnergyPLAN-Inland model reference system was built and validated using fairly recent regional data for 2009. Given the objectives of the study, few alternative systems tailored to comprehensive scenarios on the evolution of an energy system are synthesised. Focus is on the replacement of the existing intensive direct electric heating system with waterborne heating systems using district heating, heat pumps, bioheat boilers and solar thermal as a heat source. The analysis period is a year, with high time resolution of an hour. The reference and alternative system energy flow diagram is shown in Fig. 6.

The run-of-river hydro is modelled using the inflow distribution, assuming that zero spillway flow or all the inflow will be used for production. For the reservoir hydro, EnergyPLAN assumes the initial reservoir level to be 50% and optimises production based on maximum turbine capacity, inflow and storage capacity. One of its modelling shortcoming is, it is not possible to put restrictions on the minimum and maximum reservoir level. Hydro production is fully driven by the market price and generating power during high market price hours, while considering limitations of storage and generator capacity.

Heating demands are aggregated into three categories: individual, industrial and district heating. Hourly heating load profiles are based on heating degree days (HDD) of eighteen locations in Inland; hourly wind production is based on hourly wind speed of three locations in Inland and the 1.65 MW Vestas V82 wind turbine performance curve; and hourly solar production is based on the simulation made in Paper I. All investment options are exogenously predetermined. Operational strategies are then optimised, and the final attributes, i.e. PEC, RES share, system cost, import-export balance and emission levels, are determined.

In Paper II, the analysis is based on connected island mode (technical optimisation), as the aim is to balance the system internally for optimal resource utilisation; critical excess electricity production (which is above the available transmission capacity) regulation is not applied, as this would cut back the electricity imbalance.

In Paper III, the analysis is based on connected mode (business-economic cost optimisation) where the system interacts fully with the external electricity market to minimise the total annual energy supply cost. In this mode, the system imports electricity if the marginal power production cost of each plant is higher than the market price, and vice-versa. It is important to note down the impact of biomass and electricity prices on a district heating system operation built on heat pumps and bio-heat boilers.

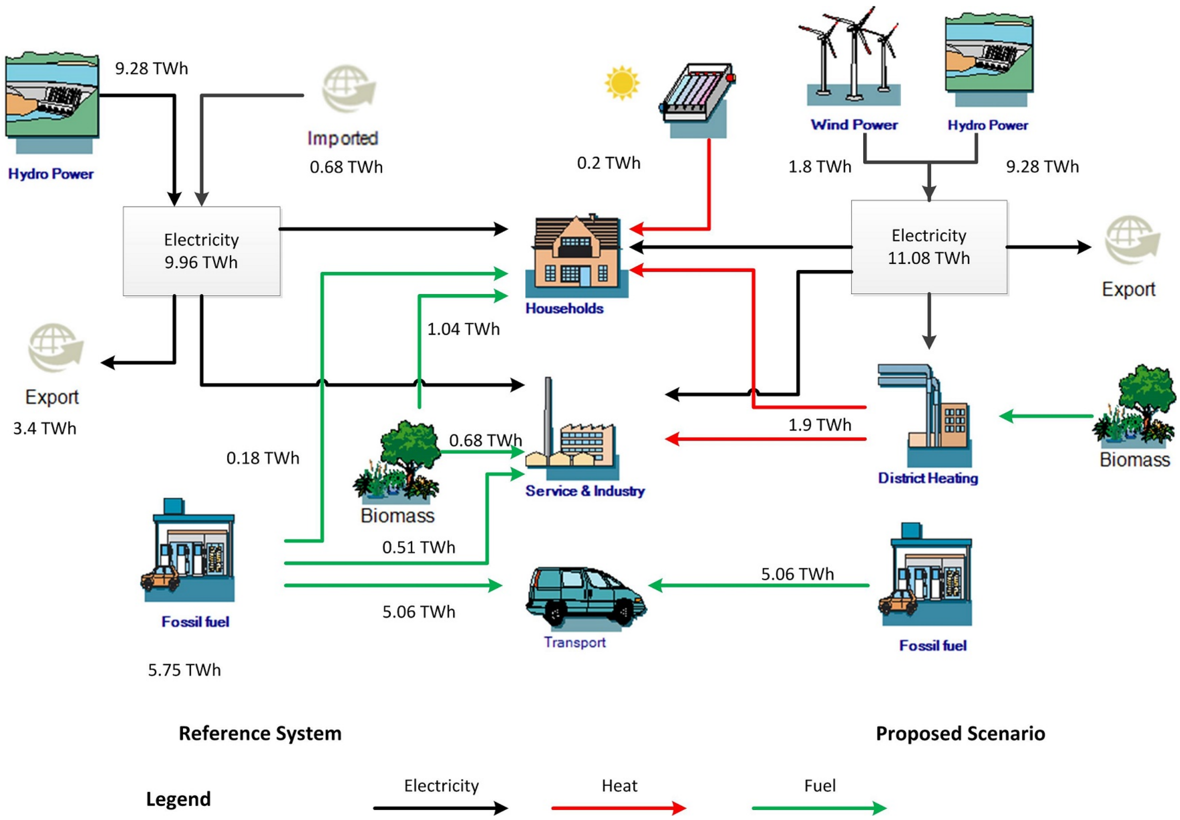

Figure 6: Inland reference and alternative system energy flow diagram (pictures are credited to ifu Hamburg GmbH)

Given the scope of Paper II and III, we do not have a CHP in the models but have used a very small dummy CHP capacity to exploit the inherent properties of the model.

3.5 Model development in TIMES

Compared to the EnergyPLAN-Inland model, the TIMES-Inland model is a technology rich, disaggregated heating demand level and evolves over a longer time horizon (2009-2030). The heating demands are classified as individual, central and district heating (DH), and the corresponding technologies as direct heating, waterborne heating and DH. In the model, all waterborne heating technologies are linked with hydronic distribution system and made available as an investment option.

Even though the model size (Inland energy system) is not large enough to challenge the computation capability and time of ordinary computers, the modelling framework in large models (like TIMES) forces the identification of the critical time periods in each year, so as to capture the supply and demand dynamics of the energy system. The fact that hydropower is the main source of power supply and that electricity is the main commodity both for electricity-specific consumption and heating purposes means that its availability will be greatly affected by inflow variations. For the aforementioned reasons, the time slices are divided on a seasonal and diurnal basis. The diurnal variation is due to peak and off-peak hour demands. Therefore, a year is divided into four seasons, each represented by an average diurnal distribution (24 hours). Thus, we have a total of 96 time slices.

The hourly wind production and heating demand profiles are constructed in the same way as for EnergyPLAN. TIMES' special features enable us to model the time dependence of the availability of process input energy carriers and efficiency, and to put restrictions on the minimum and maximum storage level on all time slice basis. Heating demands are disaggregated into as many as eight in the residential sector and five in the service sector. These are also limited to access to technologies, in order to avoid a sudden shift in the technology mix. The overall model structure, consisting of various heat demand technologies, modelled regions and an energy carrier flow diagram, is shown in Fig. 7.

Spatially, the modelled regions are divided into three: (1) the Inland region; (2) renewable energy resources supply region; (3) import-export market region (Nord pool bidding area NO1). The renewable supply region is designed to create or mimic an elastic biomass supply function. The biomass (wood chips) is classified into three categories, based on maximum harvest volume and price, meaning that there would be more biomass supply for an increased price.

For the analysis, the base case biomass price is kept constant, as the current level of harvest is very low and a supply increase could offset the incremental costs in the short run. However, the electricity price is assumed to follow coal price development according to the IEA forecast.

In a Nordic electricity market import-export context, the price is sensitive to volume and tends to increase the export region price and decrease the import region price. However, this effect has not been considered here, due to the fact that each area shares the same market region (NO1), and Inland is a sub-region of NO1. Therefore, ample transmission capacity to accommodate all production and import-export levels at all time slices is assumed to be available.

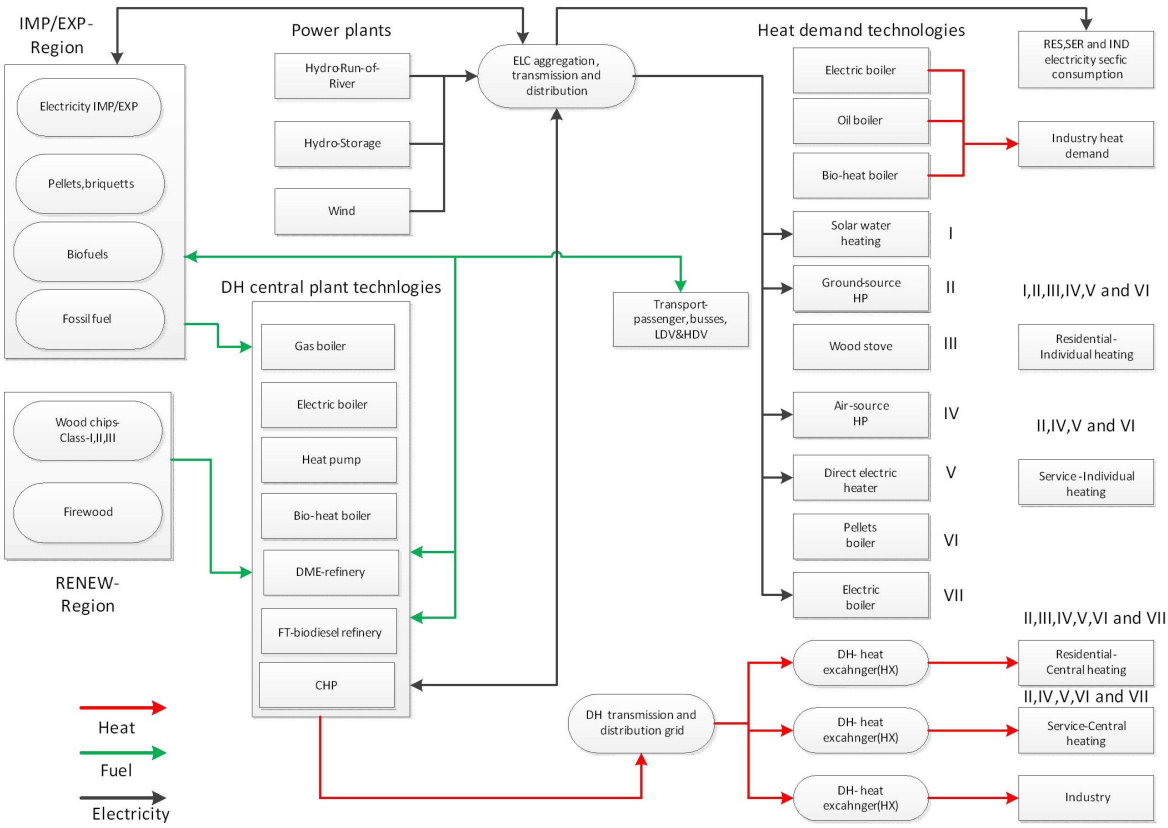

Figure 7: Model structure and energy flow diagram.

3.6 Energy system optimization criteria

In energy system optimisation, as briefly discussed in [90, 91, 92], there is no absolute single criterion for optimal design. Instead, the optimisation criteria depend on the nature of the modelled energy system and objective of the study. For example, the ability and benefits of wind integration into thermal power-intensive energy systems has been defined in terms of avoiding excess electricity production, reducing PEC, and CO_2 emission reduction in [93, 94, 73, 72], reserve power requirement in [95]. and grid stability and delivery of ancillary services in [96].

However, important and essential elements of a holistic approach are to use PEC to account for system energy saving, RES share for measuring the penetration of RESs, CO_2 emission level for measuring decarbonisation level and socio-economic and business-economic costs to identify least-cost pathways.

Let us define the basic terminology: primary energy refers to the energy content of the source (like crude oil, coal, wood, hydro); primary energy consumption is all primary energy used to produce secondary energy at the system boundary of the conversion plant; secondary energy refers to energy commodities (like electricity and heat) after the conversion process and at the system boundary of the conversion plant; and final energy consumption accounts for all secondary energy to the end user (household, service, industries and transport) after subtracting distribution and transmission losses.

PEC could be roughly calculated as all domestic production plus energy imports minus energy exports. The RES share could be calculated as the sum of all energy production from renewable sources divided by PEC or total final energy consumption. The burden of achieving an increased RES share would be reduced if it is calculated using total final energy consumption instead of PEC. When calculating PEC, the fuel equivalents of all RESs are assumed to be identical to the electricity production, this is in accordance with International Energy Agency (IEA), Organization for Economic Co-operation and Development (OECD), and Eurostat methodology.

Norway is not an EU member state, but it does abide by all EU Renewable directives through the European Economic Area (EEA) agreement and by strong self-will. The targeted 67.5% RES share by 2020 is set on the total final consumption. Therefore, calculating the RES share in final energy consumption is useful at a national level. However, at regional level, two approaches could be used: to assume that all savings would be injected into the national energy system and calculate RES share of total domestic production (as used in Paper II) or to assume that net savings would be exported outside the national system boundary (most likely if all regions take the same efficiency measures) and calculate RES share in PEC (as used in Paper III).

Given the objective of the analysis, a self-sufficient and flexible renewable based energy system design, the fuel equivalent of imports is assumed to be identical to electricity production and the source to be marginal condensing power plants in the Nordic electric market.

In Paper II, the objective function minimises the PEC, and the RES share, CO_2 emissions and socio-economic costs are extracted attributes used for the analysis. In Paper III, the objective function minimises the total system business economic costs, and the PEC, RES share and CO_2 emissions are extracted attributes used for the analysis. In Paper IV, since it is a fully economic model, the long-term discounted system cost is used as an optimising criterion and the technology mix and production levels are extracted attributes used for analyses purpose.

4 RESULTS AND DISCUSSIONS

In this section, a summary of the results of Papers I-IV is presented and discussed in relation to the main and sub-objectives stated in section 2. The first sub-objective, concerning increased use of bioenergy, is addressed in section 4.1; the second sub-objective, about increased RES share, is addressed in section 4.2; the third sub-objective, about wind energy contribution to power supply security, is examined in section 4.3; there follows CO_2 emission reduction potential in section 4.4 and techno-economic benefits of alternative technologies in section 4.5.

The results are based on the following key assumptions. In Paper I, for the base and sensitivity cases, the future electricity price is assumed to escalate annually at 5% and 0%, respectively, over the 2009 price - lower than the average 8% escalation rate in Norway for the past decades. In Paper II, the system is analysed in connected island mode or import-export is allowed whenever the system is required to do so and not influenced by the market price. In Paper III, the system interacts fully with external electricity markets with a specified historic hourly wet (8.06 €/GJ), normal (11.11 €/GJ) and dry year (14.44 €/GJ) electricity price. Different scenarios are analysed with an assumed low (6 €/GJ), medium (8 €/GJ) and high (10 €/GJ) biomass price. In Paper IV, for the base case, the electricity price is assumed to follow coal price development, as the variable cost of marginal condensing power plants is a major price driver in the Nordic electricity market. Therefore, the assumed electricity price by 2030 is 9.85 €/GJ. The future biomass price, for the base case, is assumed to be the same as the current price (4.32-5.45 €/GJ) and kept constant over the whole model horizon. The reason for this assumption is that since the current level of harvest is very low or below the sustainable yield, in the short run, a supply increase could offset the incremental costs that could arise from increased demand. Different scenarios are analysed with an assumed biomass and electricity price escalation over 2009: SC-1 (2.5% escalation and base price), SC-2 (base price and 2.5% escalation), SC-3 (2.5% escalation and 2.5% escalation), respectively.

4.1 Increased bioenergy use

One of the objectives is to identify the optimal use of bioenergy from techno-economic perspectives. This has been addressed in Papers II-IV. Bioenergy application for bioheating in Paper II, bioheating and biofuel in Paper III, and bioheating, biofuel and electricity in Paper IV have been considered and compared with other conventional technologies.

The results from Papers II-IV show that the use of bioenergy for bioheating is in strong competition with water to water HPs in central and DH systems. Given the assumptions in this study, the excess green electricity availability and the year round high efficiency of HPs make bioheating a less preferable option over HPs in central and DH systems. From a cost perspective (Paper III), Fig. 8 shows the impact of biomass and electricity price on the DH production share built on bioheat boilers and heat pumps. Electricity price is found to be the major impact parameter for bioheating to be profitable over HP, and limited to 12% in wet and normal years and 40% in dry year. Similarly, from a technical perspective (in Paper II), the share of bioheat boilers was limited to 20%. This suggests that, low biomass price alone would not increase bioheat's competitiveness unless it is complemented by a high electricity price. However, HP is a highly developed and cost-effective technology, especially in a system dominated by green and excess electricity production, and may serves as a relocation and peak load shaving technology as well.

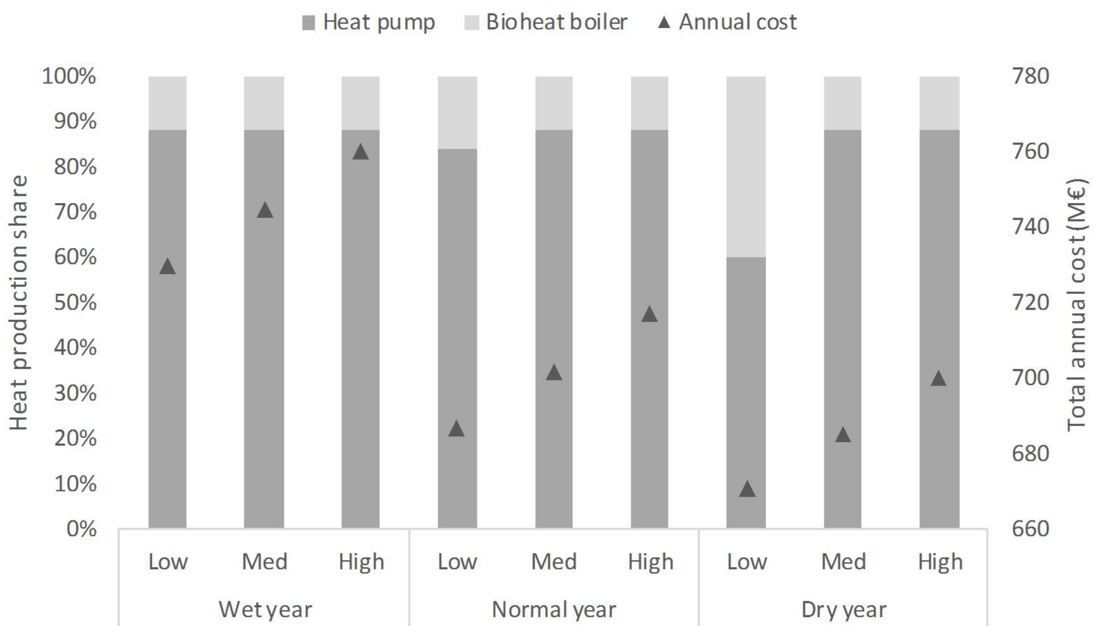

Figure 8: Total annual cost and DH (0.5 TWh) heat production share built on heat pumps and bioheat boilers for various electricity and biomass price levels. The lower annual cost (system cost), for the dry year case, is due to the high electricity price and hence increased revenue from electricity trade, which in turn offsets a large part of payments. The results are taken from Paper III.

In a cost-optimised system, the modelled long-term optimal heating demand technology mix in individual and central heating systems, from Paper IV, is shown in Fig. 9, and the DH central plant composition is shown in Fig. 10.

One of the most commonly mentioned reasons for low penetration of bioheating in the residential sector is the lack of a hydronic distribution system or a waterborne heating system. In Paper IV, however, it was shown that the biomass price is a more significant factor than the availability of a hydronic distribution system. This was noted by comparing the investments in existing buildings with and without a hydronic distribution system. In existing buildings with a hydronic distribution system, investment in water to water HPs was found to be more profitable than bioheat boilers, while the replacement of direct heating with waterborne heating was not found to be profitable, effectively implying that the biomass price is the determining factor for bioheating to be profitable over HP.

Bioenergy use in efficient modern wood stoves is found to be profitable in direct heating systems. This is shown in Paper IV, where the merit order is found to be wood stove, air to air HP and direct electric heating. However, due to the nature of construction and size of the system, wood stoves comprise only 50% of the space heating demand and function as a complement to direct electric heating and heat pumps.

From a long-term perspective, the prospects of bioenergy for electricity, heat and transport biofuel application were studied in Paper IV. The use of bioenergy for electricity in CHP depends much more on future electricity prices than on the biomass price. In Paper IV, it was shown that, for CHP to be competitive and profitable in a DH, a minimum electricity price of 9.85 €/GJ is required at the current biomass price. However, for increased penetration, the base price (2009) should escalate annually at a rate of 2.5%. This can be noted in Fig. 10 for SC-2 and SC-3 cases.

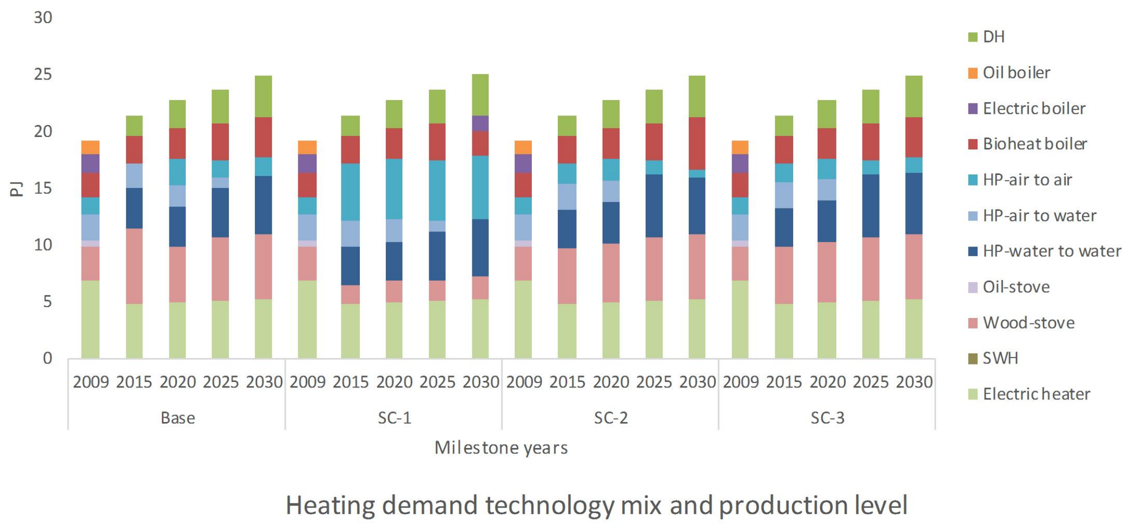

Figure 9: Heating demand technology mix and production levels of the whole energy system as it evolves towards 2030. The technology mix is an aggregate representation of the residential, service, and industri sectors. The results are taken from Paper IV.

Techno-economically, the use of bioenergy as biofuel for transport purposes is found to be feasible with a certain subsidy level. In Paper IV, a hydrogenated DH integrated biorefinery is proposed and analysed for increased use of bioenergy in the future energy system of Inland Norway. The biorefinery not only increases the use of bioenergy but also creates a synergy effect between the electricity, heat and transport sectors through integration of technologies and RESs. However, due to its high investment cost, a minimum of 6 €/GJ biofuel subsidy is required to initiate investments in a DME-biorefinery for the base case price scenario. For a higher energy price scenario (biomass and electricity), FT-biodiesel is found to be profitable over DME and requires a minimum of 12 €/GJ biofuel subsidy.

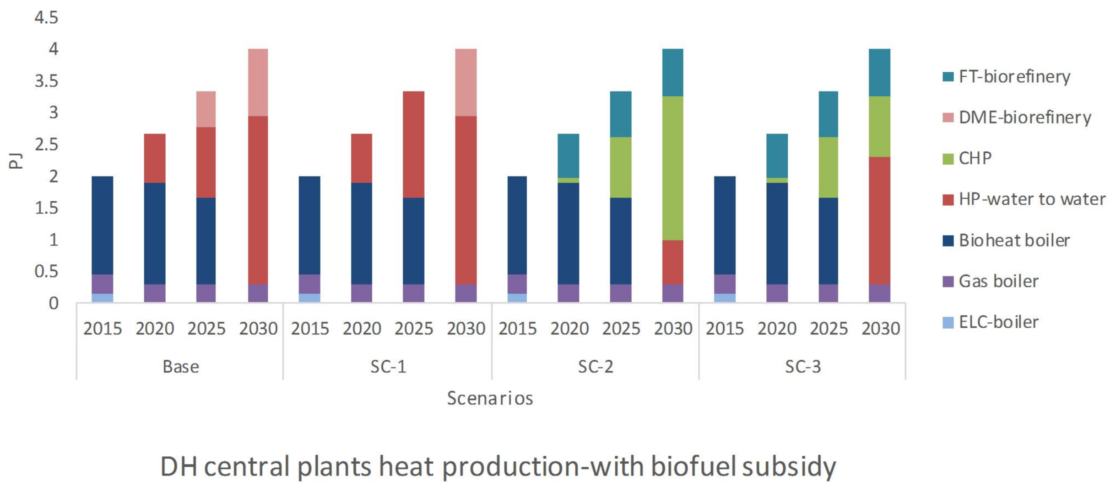

Figure 10: DH central plants composition and production mix evolvement towards 2030 when the minimum required biofuel subsidy for biorefinery technolgies is included. The results are taken from Paper IV.

DH takes a relatively small share of the heating demand in Inland and Norway at large, but following the energy policy objectives for increased use of bioenergy, in the last couple of years several new plants have been approved for installation. More than 70% of heat production comes from wood chip fired bioheat boilers in emerging DH systems. However, the results show that the use of intensive virgin wood biomass firing boilers (bioheat boilers) in DH is not the best option. Instead, HPs are better alternatives. This implies that there is an opportunity cost associated with intensive use of bioheat boilers in DH instead of HPs. In Paper III, the opportunity cost was calculated in terms of equivalent marginal production cost increase and found to be in the range of 0.56 €/GJ (in wet year) to 2.22 €/GJ (in dry year). Therefore, earmarking bioenergy for biorefinery and for high-quality heat production in industries where otherwise HPs would not be used is a better alternative solution. The assumption is, by the time the existing bioheat boilers are phased out, commercialisation of second generation biorefineries would most probably have begun.

In Paper I, techno-economically, solar thermal for a residential hot water heating application was found to be feasible; but as shown in Fig. 9, in Paper IV, it was found to be uncompetitive over electric heating, water to water HPs and bioheat boilers. The results largely depend on the different assumptions that have been made in both papers on the future development of the electricity price. In the last decade (2000 to 2010), the electricity price in Norway has increased annually by an average of 8% [10]. Recently, the price has reduced substantially and reached the same average level as other European countries. There are different views regarding future electricity price developments. The increased integration of VREs and energy efficiency are price-reducing factors, while quota schemes, additional green electricity charges and increasing fossil fuel prices are price-increasing factors. Therefore, optimistic assumptions of 5% annual electricity price escalation in Paper I and 2.5% annual electricity price escalation in Paper IV have been made to simulate and analyse scenario cases. The results indicate that solar thermal would be feasible only under a 5% escalation rate. Following this, solar thermal investment was not seen under the 2.5% escalation scenario in Paper IV.

4.2 Increased RES share

The second sub-objective was to investigate the technical and economic aspects of different alternatives for an increased RES share. In a system constrained by supply and demand, the RES share can be improved by either increasing renewable energy use or lowering PEC - increasing energy efficiency or both. This is calculated as: total domestic renewable production - corrected for import and export - divided by total PEC. Energy efficiency could be achieved using insulation, efficient technologies and/or energy consumption behavioural change. In this specific context, energy efficiency refers to the use of more efficient technologies. In this study, bioheating and biorefinery technologies increase the use of RES while heat pumps increase energy efficiency and lower PEC; in the RES share estimation, the former is the numerator while the latter is the denominator. The RES share has been calculated assuming that the net energy saving would be injected into the national energy system (Paper II) and would be exported outside the national system boundary (Paper III). The latter assumes that all other regions in Norway would implement the same measures as Inland Norway, resulting in an increase in the net exports outside the national system boundary.

The results indicated that bioheating and biorefinery technologies contribute more to an increased RES share than heat pumps. The synergy effect of the biorefinery technology and the fact that DME is used in conventional internal combustion engines make the DME pathway even better than BEVs and HFCVs.

In Paper II, the RES share was estimated to be 67.5% for the reference system and 74.5% and 71.8% for the alternative systems (labelled as scenario-1 and scenario-2) respectively. Scenario-1 is built on intensive use of traditional bioheat boilers in DH,

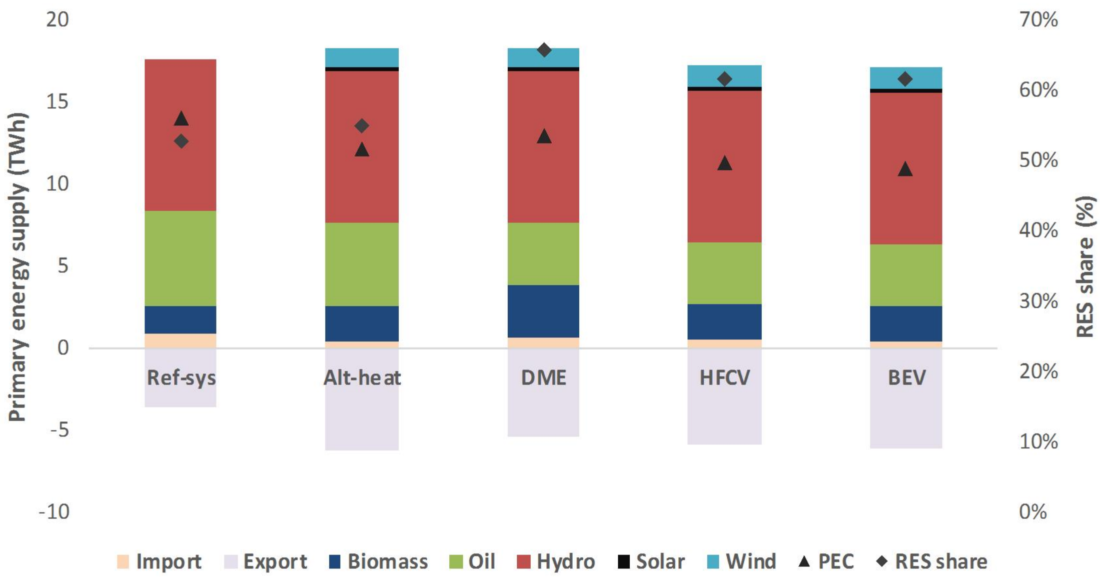

Figure 11: Primary energy consumption (PEC) and RES share of the reference and alternative systems in a normal year. Primary energy supply (PES) refers to domestic production while PEC is domestic production corrected for import and export. DME refers to an alternative transport system based on dimethyl ether, BEV based on batter electric vehicles, and HFCV based on hydrogen fuel cells pathway equivalent to the displacement of 1 billion km annual road traffic volume. The results are taken from Paper III.

while scenario-2 is built on heat pumps and bioheat boilers.

In Paper III, as shown in Fig. 11, the overall RES share in the reference system for a normal year was 53%. This share increased to 55% for alternative heating system case and, on average, alternative heating and transport systems altogether amount to 66% for DME pathway and 62% for HFCV and BEV pathways. Comparing the reference system (53%) and the average of DME, BEV and HFCV (64%), it shows an 11 percentage points increase. However, increased use of bioenergy would increase the RES share more than increased energy efficiency due to BEV and HFCVs, which lowers the total PEC. This could be seen by comparing the DME (66%) and the average of BEV and HFCV (62%), which shows a 4 percentage points increase. This is due to, as explained in section 4.1, the synergy effect of the biorefinery plan that leads to more renewable energy use inside the system boundary or modelled region, rather than exporting it outside.

The implication is that, specifically in the heating sector, intensive use of bioenergy would be appropriate if the objective was to increase the RES share; however, from the cost perspective, it has an associated opportunity cost, as heat pumps are often more efficient and cost-effective technologies than bioheating.

Looking more specifically into the transport sector, in Paper III, the displacement of

1 billion km annual road traffic volume, and in Paper IV, biofuel blending in standard vehicles with a 2-20% mix ratio (by energy) in the future transport demand (2030) were studied. The results showed a 20% and 25% RES share, respectively, which is more than double the targeted 10% RES share by 2020 of the Inland Norway Energy Agency.

Generally speaking, energy conservation measures, efficient technologies, insulation and energy use behavioural change would reduce the total PEC and thus reduce the need for additional investments in renewable power plants. On the other hand, greater penetration of bioenergy in the transport sector would contribute to substantial emission reduction and an increase in the RES share. Therefore, as reflected in the alternative systems (Paper II and Paper III), earmarking heat pumps in the heating sector and biomass as biofuel, which would otherwise not be covered by BEVs such as heavy duty vehicles, in the transport sector would help to increase the RES share and achieve the regional energy policy targets.

4.3 Power supply security

The electricity production mix is 100% hydropower - reservoir (40%) and run-of-river hydro (60%). The hourly average of weekly electricity imbalance for the reference system with and without wind power is shown in Fig. 12. The assumed wind power capacity is 700 MW/1.8 TWh. The hourly simulation shows that, without wind power, even though production is in excess, the system imports 10% of the total electricity demand during peak demand periods of the winter season and exports 36.6% of the total production as excess during high precipitation periods in summer. With the assumed wind power, however, more than 21% of the yearly wind power production was able to reduce imported electricity in less than 23% of the annual production time (weeks 47-12), contributing directly to peak load supply. Import is directly related to supply security. A forced import would occur when demand is higher than peak load power plants capacity and/or reserve margin/capacity. In the Nordic electricity market, the marginal power plants are condensing power plants which are of a firm capacity. Therefore, any import avoided by wind energy is equivalent to avoiding firm capacity.

Capacity credit is a parameter used to measure the level of demand or load that could be supplied by VRE without increase in the loss-of-load probability (LOLP)[3]; more often defined as the ability to displace an equivalent amount of 100% firm capacity or conventional power plant capacity without compromising system reliability [97].

The fact that run-of-river hydro is a 'use-it or lose it resource', like wind and solar, with

[3]Defined as the probability that the available generation capacity at any particular time is less than the system load.

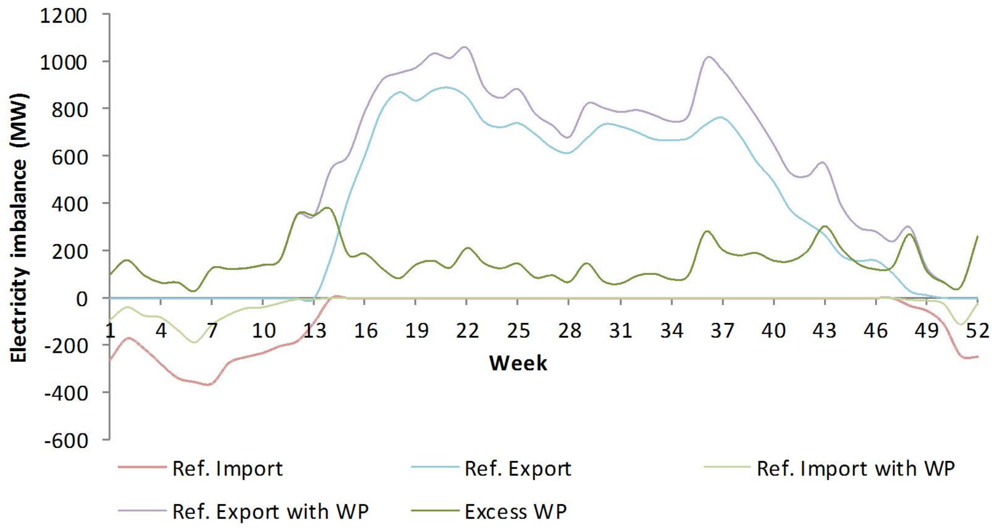

Figure 12: Weekly electricity imbalance of the reference system with and without 700 MW/1.8 TWh wind power (WP). Weeks 13-46 are high production time-summer, while 47-12 are high demand time-winter season. The results are taken from Paper II.

low precipitation during peak demand periods, makes it less favourable for reducing imports. By contrast, wind speed is stronger in winter than in summer, and wind power availability is more generally in phase with demand. Furthermore, as opposed to hydropower, which varied on a seasonal and a yearly basis, wind power production varied within minutes but remains fairly constant on a yearly basis. To this end, wind energy ensures supply security better than small-scale run-of-river hydro. In Paper II, as shown in Fig. 12, the technically optimal wind energy penetration level was found to be 22% (22% of the total electricity production originates from wind power).

The main factors that determine the capacity credit of VRE technologies, as discussed in [97], are as follows: (1) the correlation between the peak demand and variable output or intermittency of the VRE - the larger the correlation, the better the capacity credit; (2) the average level of output or capacity factor - the higher the average output during peak demand periods, the better the capacity credit; and (3) the range of intermittency of the VRE - the more uniform the output, the better the capacity credit.

The capacity credit was not stated explicitly or calculated in Paper II; however, in this thesis, using Fig. 13 , the capacity credit at different wind energy penetration levels has been calculated and was found to be in the range of 22% to 9% for 16% to 38% wind energy penetration levels, respectively. The result shows better capacity credit at lower penetration levels. The results are broadly in line with previous studies, for example, in [97, 98, 99].

Given the fact that import occurs during peak demand periods and that the system is in excess without wind power integration, with the assumed wind power or approved wind power in Inland (700 MW/1.8 TWh), the capacity credit of the wind turbine for system adequacy would be 21% - meaning that 21% of the total installed wind power capacity is available as firm capacity.

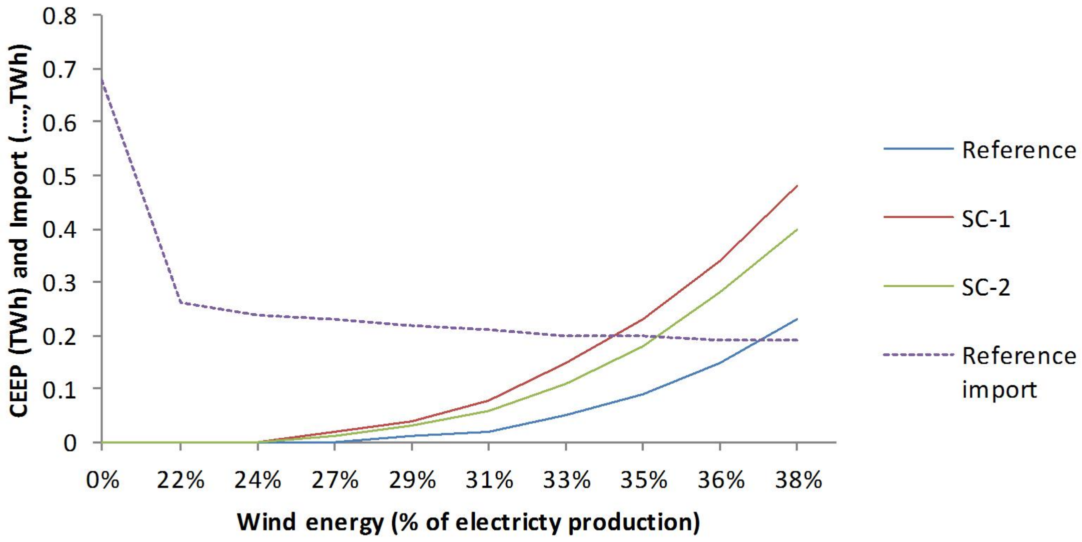

Figure 13: Critical excess electricity production (CEEP) and Import electricity for increasing wind energy penetration level in the reference system (Reference) and alternative energy systems (SC-1 and SC-2). The results are taken from Paper II.

The role of wind power in reducing imports and limiting biomass consumption in a DH system built on heat pumps and bioheat boilers was also studied in Paper II. In the assumed composition of DH central plants, regarding the capacity share of heat pumps, two cases were considered - a 25% and a 50% capacity share. As the results showed in Paper II, doubling the capacity share of heat pumps would increase their DH production share by 7 percentage points, while the imported electricity in the system would be reduced by 20%. This implies that with increased DH demand, the assumed wind energy penetration level could be increased further if a large-scale heat pump installation was incorporated. In this particular case, limiting the biomass consumption and reducing imports would be the ultimate benefits of wind energy.

The impacts of wind power on the electricity market and its market value are not considered in this study but could be found in [20]. However, wind power profitability in a future energy system has been studied in Paper IV. With an assumed electricity price (9.85 €/GJ) towards 2030, all the planned wind power and small-scale run-of-river hydro are found to be profitable.

4.4 Techno-economic benefits of alternative systems

The shift from intensive direct electric heating to a waterborne heating system shows a techno-economic benefit in terms of lowering the overall energy consumption and system cost. The technical benefit arises mainly in terms of allowing more integration of RESs and introducing demand-side flexibility, energy conservation and increased security of supply. Energy carrier switching (electricity to thermal) and energy conservation measures are, techno-economically speaking, competitive and result in large electricity saving. This is due to the fact that electricity and heat demand profiles are in phase and both peaking during the colder months. Thus, as a result of peak load shaving, it has a socio-economic advantage equivalent to reducing or avoiding the construction of new power plants and transmission lines. The ultimate contribution, at large scale, would be for a flatter electricity demand curve, subsequently leading to a predictable and stable electricity price.

The electricity saving, could be used for synthetic fuel production (using hydrogen as energy carrier), reduce investments in new expensive power plants at national level and increases the net export which would otherwise be covered by new investments; more than 80% of techno-economically and environmentally feasible hydro potential is already explored, and the remaining 20% is available as a small-scale hydro. On top of that, given a large part of electric energy saving, in alternative systems, is originated from peak demand periods, it reduces the burden on the transmission system and vulnerability for low precipitations.

Furthermore, integrating new RESs means diverse energy supply, which in turn contributes to system adequacy and energy supply security at regional and national levels.

In Paper II, a multi-criteria decision analysis has been done to rate the overall techno-economic benefits of the alternative and reference systems from an energy policy perspectives; in terms of improved RES share, increased net export, reduced energy consumption, CO_2 emission level and annual system cost. The result showed that, on a 0 to 100 scale, the overall scores for alternative systems (labeled as scenario-1 and 2) found to be 46.78 and 49.12, respectively and 29.48 for the reference system; the alternative systems showed, on average, an incremental score of 67% over the reference system. On top of that, even though such multi-criteria decision analysis is not done in Paper III, it is evident that the improved CO_2 emission reduction and increased RES share at a reasonably marginal incremental annual costs would further stretch the overall score over the reference system. Therefore, the benefits of alternative systems in terms of achieving the targeted energy policy objectives at both regional and national levels are immense.

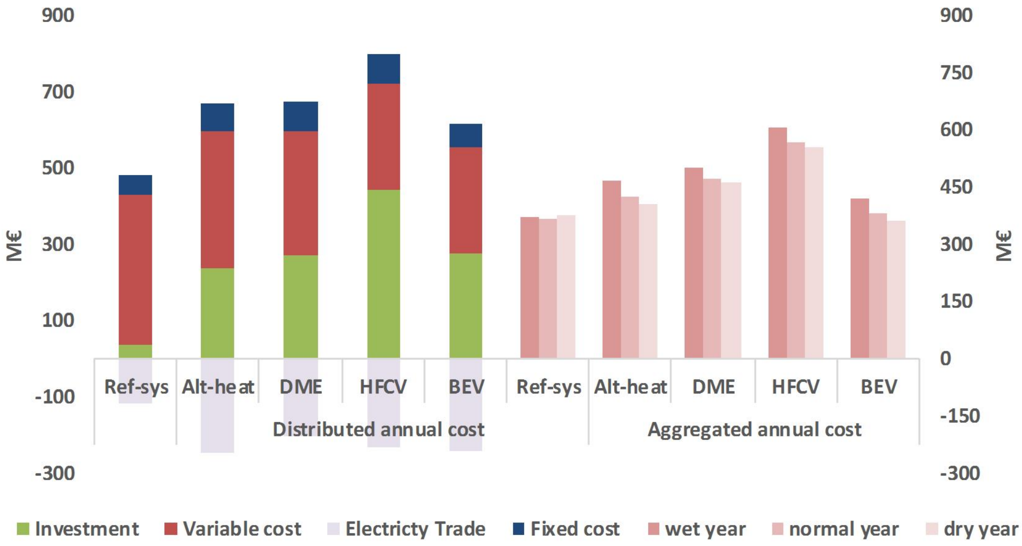

Figure 14: Detailed business-economic annual costs and aggregated annual costs of the reference and alternative systems in a normal year. The results are taken from Paper III.

It is expected that introducing flexibility measures (like in DH transmission and distribution systems) in alternative systems would substantially increase the total system cost. However, as shown in Fig. 14, despite the high investments costs to establish alternative heating system, revenue from electricity trade due to energy carrier switching and increased energy efficiency offsets a large part of the out payments and makes the incremental costs marginal. The revenue depends on the electricity price, such that dry year price pronounces the benefits more than wet year price, despite increased electricity production in a wet year. This is because even though the trade volume is increased, the low price makes for lower total revenue than in a dry year.

The major cost component in the reference system is the variable cost - fossil fuel cost. Therefore, decarbonising the transport sector is a potential avenue for lower system cost and for cost effective CO_2 reduction. In the alternative transport system, the BEV pathway is found to be the least-cost pathway, while DME and HFCV show a considerably higher system cost. Given the source of electricity, BEVs are an ideal solution; but challenges associated with slow storage battery development and low driving range are major barriers. This effectively implies that BEV is a more cost-effective CO_2 mitigation pathway than DME and HFCV.

In Paper IV, towards 2030, no investments were made in HFCVs, primarily due to their high vehicle cost, but a total of around 2,400 BEVs were invested in at the end of 2030, primarily due to their high efficiency (7 km/kWh).

4.5 CO_2 emission reduction

CO_2 emission reduction could be accounted at a regional and global scale. Given a 100% renewable power sector, excess exportable electricity due to energy efficiency measures and energy carrier switching would be largely used to displace condensing power plants production, which would otherwise be used to cover the demand in thermal-dominated Nordic electricity market, thereby indirectly contributing to global emission reduction. Fig. 15 shows both the local and global emission reduction potential.

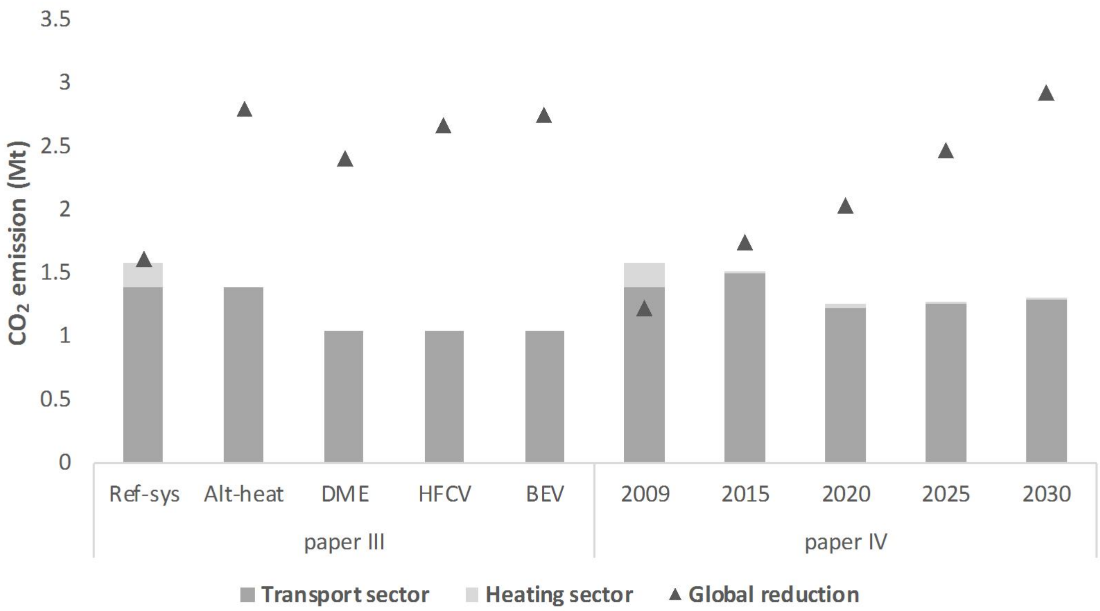

Figure 15: CO_2 emission levels of the reference and alternative system scenarios. The global emission reduction is due to the exportable green electricity assumed to replace condening power plants with an emission factor of 450 g/kWh. The results are taken from Paper III and IV.

Locally, the transport sector is responsible for more than 70% of the total emissions in Inland, and a potential opportunity to reduce emissions and increase the share of RESs exists. In Paper IV, despite the increased transport demand towards 2030, as shown in Fig. 15, the emission level was reduced by 18%. The reason is that it is partly offset by increased vehicle efficiency, i.e. EVs and diesel vehicles. The latter are efficient and less polluting than petrol vehicles, although particulate and other toxic emissions like NO_x are noticeably higher. Because of its fuel efficiency and lower fuel price, the system tends to invest more in diesel vehicles than in petrol vehicles to meet the forecasted transport demand towards 2030. However, in reality, the proportion - the share of diesel and petrol vehicles - is more or less equal. Hence, to mimic reality, the upper investment level of diesel vehicles was set at 60%, meaning that 60% of the passenger transport demand would be covered by diesel vehicles. As a result, the total emission level was found to hover around 1.27 Mt.

Global CO_2 emission reduction is far higher than local reduction. Towards 2030, as shown in Fig. 15 of Paper IV, increased energy efficiency and energy carrier switching, coupled with additional new generations, increase net exportable green electricity; hence, its contribution to global CO_2 emission reduction increases substantially. The discrepancy between Papers III and IV is the accounting method. In Paper III, export (not corrected for import) was used, while in Paper IV net export (corrected for import) was used to estimate global displacement. The Intergovernmental Panel on Climate Change (IPCC) counts emissions based on production, while different commentators and studies claim that consumption based accounting is essential to consider the embodied emissions associated with imports [100, 101].

In Paper III, the DME pathway shows a better synergy effect through the use of excess electricity for hydrogen production and limiting biomass consumption in biorefineries; consequently, that reduces the exportable electricity and global CO_2 emission reduction potential.

5 CONCLUSIONS

In this study, firstly, a scenario based alternative systems (operation strategy optimisation) tailored to a comprehensive solution to a flexible energy system were formulated and analysed as an alternative to an electricity-intensive energy system (Paper I-III). Secondly, in a separate study, the long-term development (investment and operation strategy optimisation) of the existing energy system under various frameworks was analysed (Paper IV). The primary objective is to see more integration of renewable energy technologies that introduce flexibility measures for increased use and integration of RESs from overall system perspectives, i.e. electricity, heat and transport sectors. Based on the two subsequent studies, the following conclusions are drawn.

The results reveal that, with the current and assumed biomass and energy prices development, heat pumps are more profitable solutions in individual, central and district heating (DH) systems. One of the most commonly mentioned reasons for low penetration of bioheating in the residential sector is the lack of a hydronic distribution system. In this study, however, the biomass price is found to be the main factor. This was noted in residential and service sector buildings equipped with an existing hydronic distribution system, where water to water HPs were preferred over bioheat boilers. However, in buildings without hydronic system, efficient wood stoves as a replacement for old wood stoves were preferred over electric heating, though limited to 50% of the space heating demand at most. The merit order is found to be wood stoves, air to air heat pumps and electric heating.

In alternative systems (Paper II and III), all investments were exogenous while in long-term model (Paper IV) investment were endogenous. As shown in Paper IV, with the assumed energy price development, waterborne-heating deployment is found to be less attractive over direct heating. This effectively implies that, given their benefits for competition between heat sources and for low-temperature heat sources utilization, regulatory or strong market based polices must be implemented to increase the share of waterborne heating systems. For example, this would embrace a call for more stringent regulations in the building code.

It is also found that in the DH market, there exists an opportunity cost associated with the vast allocation of virgin wood biomass boilers (bioheat boilers) in DH central plant composition. Instead of bioheat boilers, water to water HPs are found to be profitable technologies; further, this is relevant technically, for damping excess wind power and limiting biomass consumption. Towards 2030, with assumed development of the electricity price in the Nordic electricity market and tradable green certificate (TGC), CHP is also found to be a profitable investment. For increased share of CHP in DH, the electricity price is also found to be the determining factor over biomass price. If electricity price increases annually at 2.5% over the base price (2009), with the current biomass price the share of CHP in DH would be 35% by 2030. HPs and CHP are the most developed and matured cost competitive technologies but are given less attention in the emerging DH market. The main perceived reasons are high investment cost, performance factors (HPs) and low electricity price (CHPs). Given the benefits of these technologies for a flexible energy system, however, policy instruments should be designed to promote and prioritise them over bioheat boilers in a future energy system.

Two DH integrated second generation biorefineries (DME and FT-biodiesel) were selected to decarbonise transport and make use of its synergy effect in integrating the entire energy sector, i.e. electricity, heating and transport. Even though the specific investment cost of DME biorefinery is lower than FT-biodiesel, the high biogasoline price (and hence revenue) of FT-biodiesel levels off the incremental costs, and it was difficult to make a clear distinction on the cost advantage prior to this system perspective study. For the base price case, DME biorefinery is found to be preferable over FT-biodiesel, and a minimum of 6 €/GJ biofuel subsidy is required to initiate investment in DME. However, at a higher electricity and biomass price, FT-biodiesel is found to be preferable over DME, and a minimum of 12 €/GJ biofuel subsidy is required to initiate the investment. Investment is the major cost component that leads to a higher biofuel subsidy.

Biorefineries are not cheap enough to displace the HP heat production share in DH, instead, it occurred to reduce the share of CHP. The higher subsidy level (12 €/GJ) is, to some extent, related to CHP competitiveness at higher electricity price. Moreover, the existence of tradable green certificate (TGC) happens to increase the required level of biofuel subsidy; however, it was found to be marginal (1 €/GJ) in all price scenarios. To sum up, for increased bioenergy use in a DH system, biorefinery and CHP are found to have priority over bioheat boilers. However, if the price of biomass hovers at its current level, a high electricity price favours both CHP and bioheat boilers by 2030.

The value of wind energy is expressed by reducing imports during peak demand and low precipitation periods in winter, and it shows a moderate capacity credit as high as 21% at lower penetration level.

This thesis also reveals that even though both increased use of bioenergy and heat pumps increases RES share, the former increases the RES share more than heat pumps would.

In conclusion, using heat pumps for low-quality heat production in individual, central and DH systems, and earmarking biomass as biofuel for transport purpose are found to be a cost effective solution in terms of achieving energy policy goals.

6 LIMITATIONS OF THE STUDY

The spatial variation of resource availability and availability of ample transmission capacity in RESs integration greatly impacts the integration cost and market value (hence, investments levels) of RESs, especially for VREs. Given the large number of power plants in the region, the assumed unified installed capacity and production for modelling purpose is a coarse assumption. In fact, the accuracy of simulation results in production deficit in winter and excess in summer was compared with various regional reports, seminar presentations and personal talks with experts, and found to be reasonably very close to the aforementioned sources. Capturing a representative inflow distribution is a complicated issue. This is because, to maximise production, it is a common design practice to cascade hydro power plants in series. This needs to capture site-specific conditions (inflow and production), hence a finer spatial resolution. This was the big limitation of the study and has not been captured in it.

In Papers II and III, the biomass supply is assumed to be price inelastic. In Paper IV, however, the biomass supply is designed to mimic an elastic supply function by dividing the biomass into three classes with distinct price and volume, so that the model could jump to high price biomass if demand increases or there would be greater supply for increased price. This is somewhat a coarse assumption and a finer biomass supply function based on actual harvest data needs to be modelled and incorporated for more accurate results.

In Papers II and III, an aggregated heating demand in individual heating was used to optimise the operation strategy but would have no impact on the technology mix, as the scenarios are drafted based on the modeller's interest. However, in Paper IV, a detailed representation of heat demand based on demand level, access to technology and end user behaviour is essential for a realistic heating demand technology mix in the energy system. Access to technology and demand levels have been considered to a certain extent, while keeping the model size reasonably small; but end-user behaviour has not been considered at all. Therefore, for a realistic representation of heating demand technologies in the energy mix, all the aforementioned categories need to be incorporated with a finer temporal resolution.

In Paper IV, two biorefinery technologies were selected to demonstrate the benefits of DH integrated biorefinery. In the model, the maximum discrete plant capacity corresponds to available DH demand. The larger the DH demand, the larger would be the plant size; hence, better use of economies of scale. However, in the model, the DH demand is quite small, only 1 TWh by 2030, certainly not enough to utilise its economies of scale fully.

Even though we have used high-quality data, one major uncertainty is the assumption of future development of investment cost of alternative technologies. Given the fact that any economic study is highly volatile, the results should be based on the assumption that an increase in investment and operation cost will have a considerable impact on them.

7 FUTURE RESEARCH

The solar thermal potential for residential hot water heating application with an auxiliary electric heater was studied in Paper I. A techno-economic feasibility study was carried out with a finer temporal resolution (hourly). It is of interest to consider a hybrid-solar heat pump system using the ground as seasonal heat storage. This could potentially increase the solar fraction (the share of heat demand covered by solar thermal) and reduce the compressor run time, which in turn creates a longer service time. For a homeowner who is capable of installing a ground source HP, the additional solar collector is a marginal investment cost; hence, techno-economically, it might be feasible. Finally, incorporating the output into the Inland energy system model might make the hybrid solar-heat pump a more profitable solution over stand-alone solar thermal and heat pump systems.

In this study, the benefits of heat pumps in terms of increasing energy efficiency, peak load shaving and limiting biomass consumption in DH were studied. However, it is of interest to expand further the energy model, at least, to include the whole electricity bidding area (NO1) and analyse the load shedding benefits of heat pumps for wind power integration and electricity market balancing. This is important in that large heat pumps have double circuit variable speed compressors with decent part load efficiency that could play a part in power regulation. This, however, needs to capture both investment and operation costs for an optimal investment in wind and storage based heat pumps with a fine temporal resolution. As such, operational strategy models do not capture the investments cost, while the long-term models fail to capture higher temporal resolution. Therefore, the approach is to use a hybrid model which synchronises both short-term and long-term models. In addition, considering the impacts of import-export volume on the electricity market price is essential for more accurate results.

In this thesis, only the Inland DH system was studied, which is small in size. It would be useful to expand the model size and incorporate waste incineration plants and more biorefinery pathways like synthetic natural gas (SNG). Furthermore, instead of using an average HDD profile, it would be more realistic to employ a weighted actual heat demand profile, as the building mix has a different thermal mass, and the actual demand might not be in line with HDD day profile.

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APPENDIX

Paper I

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Research Article

Solar Water Heating as a Potential Source for Inland Norway Energy Mix

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The aim of this paper is to assess solar potential and investigate the possibility of using solar water heating for residential application in Inland Norway. Solar potential based on observation and satellite-derived data for four typical populous locations has been assessed and used to estimate energy yield using two types of solar collectors for a technoeconomic performance comparison. Based on the results, solar energy use for water heating is competitive and viable even in low solar potential areas. In this study it was shown that a typical tubular collector in Inland Norway could supply 62% of annual water heating energy demand for a single residential household, while glazed flat plates of the same size were able to supply 48%. For a given energy demand in Inland Norway, tubular collectors are preferred to flat plate collectors for performance and cost reasons. This was shown by break-even capital cost for a series of collector specifications. Deployment of solar water heating in all detached dwellings in Inland could have the potential to save 182 GWh of electrical energy, equivalent to a reduction of 15,690 tonnes of oil energy and 48.6 ktCO_2 emissions, and contributes greatly to Norway 67.5% renewable share target by 2020.

1. Introduction

As the impact of fossil fuels on our precious environment is becoming more pronounced, all over the world, governments have started to implement multiple measures to increase the share of renewables in their existing fossil intensive energy systems, with these effectively emerging as political and economic issues. Within these, in 2007 the EU established the so-called 20-20-20 vision of a 20% emission reduction in reference to 1990 levels, a 20% increase in the share of renewables in the energy mix and a 20% reduction in energy consumption by 2020 [1]. In line with this, the long-term framework of EU renewable energy directives, which came into force in December 2011, has motivated the Norwegian government to set a target of increasing the share of renewables from 60% in 2005 to 67.5% by 2020 [2]. This could be accomplished by either increasing renewable energy production or increasing the share of renewables in energy consumption. The Norway-Sweden common tradable green certificate (TGC) market launched in January 2012 for 26 TWh new electricity generation cooperation is one key measure towards achieving the 2020 target [3]. On the other hand, the residential sector in Norway is energy-intensive and is a key sector to be focused on in terms of energy efficiency.

In the Nordic countries, the energy used in the building sector accounts for 33% of total energy use, of which residential buildings account for 67% and service buildings for 33% [4]. Space and water heating in the residential sector account for 60% and 13% of total energy use, respectively, while direct CO_2 emission per capita amounted to 0.24 tonnes in 2009, much lower than other OECD European countries, 0.8 tonnes [4]. This is due to the insignificant share of oil use in the residential sector. In the Nordic countries in general, electricity is a highly used commodity, followed by commercial heating (district heating). Specifically in Norway, the heating sector is "monopolized" by electricity. Due to extensive development of hydropower and low electricity prices in the recent decades in Norway, the share of electric energy used for heating in households was quite significant. Energy use in households stands at electricity 77%, biomass 18.5%, and oil 4.5% [2]. Based on Statistics Norway report [5], 65% of households' electric energy consumption was used for heating, of which 41% was used for space heating and 24% for water heating. Electric energy is high-quality energy and must be used for electricity-specific energy consumption or its value should be amplified (as in heat pumps). As opposed to this, using high-quality energy for low-quality energy production in direct electric heaters devalues the overall energy system efficiency. As of 2009, the share of households using heat pumps for space heating was only 18.5%; this increases to 33% in detached houses [6]. With this consideration, 81.5% of the remaining households use direct electric space heating, which makes the energy efficiency much worse. Moreover, a low district heating share (6%) [4] and heat pump deployment (18.5%), together with 95.2% electricity generation from a single source (hydropower) [7], are impeding system integration and flexibility between the heating and electricity sectors in Norway. In this regard, implementing energy efficiency measures together with penetration of more renewable sources in the heating sector would help as a means to cut down electricity consumption and contribute greatly to the vision of increasing the share of renewable energy by 2020.

Solar energy is a free, inexhaustible, and environment-friendly resource. Solar thermal energy for heating largely depends on solar energy availability and cost competitiveness. At the end of 2011, installed solar thermal capacity totaled 234.6 GW_{th} globally, of which 60% was installed in China, 17% in Europe, and 7% in the USA [8]. More than 85% of the installations are for domestic water heating in single family houses. These installations globally contribute 20.9 million tons of saved oil energy per annum and a reduction in CO_2 emissions of 64.1 million tonnes [8]. Chinese government policy for incentives is considered to be the main driver for significant penetration in China [9]. The Chinese government also plans to boost solar thermal installation from 152 GW_{th} in 2011 to 560 GW_{th} by 2020 [9]. On the other hand, high initial cost, a limited number of distributors, and public perceptions of aesthetics and reliability are a few reasons for the low market adoption in the USA [9].

Germany is the leading country in Europe with 10.73 GW_{th} solar collector installed capacity, which corresponds to 131 kW_{th} per 1,000 inhabitants, followed by Austrai (3.3 GW_{th}), Greece (2.89 GW_{th}), and Italy (2.09 GW_{th}), as of 2011 [8]. Germany alone constitutes 27% of the total installed capacity in Europe and greatly contributed to 17.96 $MtCO_2$ annual emission reduction in Europe and the 20% worldwide solar collector market growth in the last decade [8]. Solar thermal deployment in Europe has resulted in multiple benefits. For example, during 2010, annual solar yield of 17.3 TWh contributes to 12 Mt emission reduction, 2.6 billion € turnover from the solar thermal market, and created new job opportunities for 33,500 persons [10]. Moreover, a large volume of the annual turnover was generated by small-scale local businesses engaged in selling, planning, installing, and servicing solar thermal systems. More than 97% of the total installed solar thermal systems in Europe have been used for domestic hot water production, and the remaining 3% are connected with large-scale district heating systems. Tax exemptions and deductions are the main policy tools for increased solar heating penetration in most European countries [11]. Though tax exemptions and investment subsidies are introduced, still solar thermal energy utilization in the Nordic countries is quite low, with 436.6 MW_{th} in Denmark, 312.2 MW_{th} in Sweden, 30.9 MW_{th} in Finland, and 13 MW_{th} in Norway in operation as of 2011 [8]. In terms of collector type, 74% of the installations in Nordic countries are glazed flat plate, while 17% are covered by unglazed flat plate, and 9% by tubular collectors. Cost competitiveness with alternative technologies, low solar intensity, and low public awareness are perceived to slow down the market penetration in the Nordic countries. Within the Nordic countries, where solar intensity is comparably similar, the solar thermal share in Norway is quite insignificant. This is mainly due to cheap hydro power availability in past decades [6]. However, an annual energy saving equivalent to 752 tonnes of oil energy and a reduction in emissions of 2.3 $MtCO_2$ are estimated benefits of the installed solar thermal collectors and are key aspirations for large-scale integration. As of 2012, the ten largest solar thermal plants in Europe are located in Denmark, the maximum being 33,300 m^2. The high taxes on fossil fuels, tax exemptions for solar heating plants, deregulated electricity market, and large-scale solar thermal system cost competitiveness are perceived to further increase the market penetration in Denmark and Nordic countries at large in the years to come [8]. In Denmark and Sweden, few large-scale solar thermal systems are connected to a district heating network [8]. The Swedish government currently has a solar thermal supporting scheme for those who want to invest in solar thermal systems and offers 0.27 €/kWh or 18 €/m^2 subsidy [12]. The annual solar yield of large solar thermal systems is about 200 to 300 kWh/m^2, and the typical installation cost is reported to be in the range of 400 to 500 €/m^2 [12].

With this in mind, deployment of energy efficiency measures in all sectors could reduce electricity consumption significantly and would have a vital role in load management and increased green electricity availability. With these results, a high cut in emissions and a substantial financial return from the electricity market could be plausible. Of course, Norwegian domestic customers experience a higher electricity price in dry seasons when hydroelectric production is lower. As a means to reduce the share of electricity in the heating sector and promote energy efficiency and flexibility in the energy mix, the Norwegian government put funding and a support program in place in 2008 through Enova (national public institution for promoting energy efficiency, green energy production, and solar and bioenergy utilization in Norway) [13]. The scheme is intended to cover 20% of the total investment cost up to a maximum of 10,000 NOK (Norwegian Kroner) or $1,700 for residential energy saving projects, like solar heating, pellet boilers, and heat pumps, as an incentive. However, low solar energy potential, relatively low electricity price, and high capital costs are challenges for the implementation of SWH in Norway.

While detailed technoeconomic, market penetration and life cycle environmental impact assessment of SWHs in the United Kingdom [14, 15], Spain [9], Greece [16, 17], a typical

Table 1: Inland energy use by sector in 2009 (TWh) [6].

Source	Household	Service	Industry	Transport	Total
Biomass	1.04	0.23	0.45		1.72
Fossil fuel	0.18	0.17	0.34	5.06	5.75
Electricity	2.97	2.11	1.47		6.55
Emission ($MtCO_2$)		0.47		1.1	1.57

city in northern cloudy climate (St. Petersburg) [18], and Cyprus [19] were available, we could not find one single work on technoeconomic performance assessments of SWHs in Norway.

With a large floor area, households in Inland Norway are the highest energy consumers in the country. This paper therefore deals with the viability and use of solar water heating for residential properties in Inland Norway and the contribution to electric energy reductions as a result of possible solar heating penetration. The paper is organized in 7 sections. The first section provides background information about current energy efficiency status and challenges. Section 2 briefly discusses the method used and presents tools used for the analysis based on structure, purpose, and function. Section 3 briefly describes Inland's existing energy system by sector, household, service, and transport. Section 4 discusses technological aspects of solar water heaters, performance, and application. Section 5 presents a solar potential assessment in Inland based on observation and satellite-derived data and details of SWH system performance and an economic assessment to point out solar water heating viability, energy, and cost savings in Inland Norway. In Section 6, the value and extent of using SWH for electricity saving and imbalance enhancement in the existing Inland energy system are discussed, followed by conclusions in Section 7.

2. Method

Solar potential assessment and variability were studied for four stations available with ground measured (observation) solar radiation data in Inland Norway. Satellite-derived solar radiations from three different external sources were compared with ground-measured data so as to draw the representative solar potential and logical conclusions regarding the variability of solar radiation between Inland Norway and the capital Oslo. Based on Inland (in this paper wherever stated Inland refers to Inland Norway of Oppland and Hedmark counties) solar potential, hourly performance, and financial simulation for two types of solar water heaters (tubular and flat-plate) with electric auxiliary heating were analyzed for a typical annual hot water energy demand and load profile using the system advisor model (SAM) to estimate the maximum possible solar fraction (percentage of base energy demand delivered by SWH), energy saving, and economic viability. SAM is a tool used to simulate hourly solar collector performance and make economic assessments. SAM is a performance and financial model for renewable energy power systems. The model has been developed and provided by the US National Renewable Energy Laboratory (NREL) [20]. It has been used to model and simulate solar water heating [21], concentrating solar power (CSP), solar PV, wind, and geothermal power projects [20, 22]. Finally, the two types of SWH technoeconomic performance in light of Inland's solar potential were compared, and the extent of SWH penetration in the existing energy system and associated electricity savings were demonstrated and discussed.

3. Inland Energy Use

Inland Norway comprises two counties: Oppland and Hedmark in the east of Norway with a total number of inhabitants of 374,359 and 52,590 km^2 land area [6]. The population density in urban settlements is 982 per km^2, which is less than the national average of 1,633 per km^2 in urban settlements, making Inland rich in biomass resource [23]. The average number of occupants in single households is 2.5, and 60% live in detached dwellings [6]. Household energy consumption is the highest in the country with 26.6 MWh [6], due to the fact that individual houses in Inland have larger floor areas, and the external air temperature is relatively colder in winter.

As shown in Table 1, electricity is the most highly used commodity in every sector and also serves as the main primary energy supply for heating. The share of electric energy in total energy use in the household, service, and industry sectors is 71%, 84%, and 65%, respectively. Considering the figures in the national statistics report, 65% of electric energy use for heating and 18.5% heat pump penetration in household sector, most households in Inland use direct electric heaters and electric boilers for hot water and space heating.

Hydropower is the only source of power supply in Inland with a total installed capacity of 2075 MW (985 MW with storage and 1090 MW run-of-river) and annual generation of 9.28 TWh, as of 2009. Though no electricity import and export balance was found, the excess exportable electricity production is 2.73 TWh, and it is assumed that the system imports electricity during low precipitation periods. Biomass and oil utilization are modest, mainly used for heating in industries and households. Of the total oil demand, 88% is used by the Inland transport sector, which is considered to be the main source of emissions in the region, with a 70% share of total CO_2 emissions. Solar energy use in Inland is unknown, as statistical data is not available. This might be due to its insignificant amount or nonexistence in the region.

4. Solar Water Heaters (SWHs)

Other than solar photovoltaic (PV), the most popular and economical mode of solar energy utilization seems to be solar water heating. Few system components and low investment and operation costs make SWH suitable for low-temperature applications, that is, below 80°C [24, 25]. Basically, there are two types of SWHs: active (with pump) and passive (without pump). In cold countries like Norway, where freezing in the system components is a problem, active SWH is usually recommended. The latter is used in warm weather conditions. A typical active solar water heater consists of a collector, storage tank, pump, heat exchanger, and auxiliary heating system. The working fluid might be pure water, glycol, or other fluid with high specific heat capacity. The most commonly used solar collectors are glazed flat plate and evacuated tube (tubular) collectors. Of the SWHs in operation around the world at the end of 2011, 62% were tubular and 28% were of the glazed flat plate type [8]. A detailed SWH system description and working principle can be found here [26]. The collector efficiency depends on a number of parameters: system configuration, optical properties (absorber, insulation, back cover plate, etc.), working fluid, supply temperature, total radiation, and ambient air temperature are some to mention. This was shown in [27], a review of various experimental and theoretical studies of flat plate and tubular SWH systems. For example, a tubular collector working on water as a working fluid and outlet temperature 32°C has collector efficiency of about 59%, while flat plate with same working fluid and outlet temperature of 38°C has attained 52%. However, in general, the average annual system efficiency for a well-designed glazed flat plate collector ranges between 35% and 45% while that of tubular collectors is between 45% and 50% [28]. Flat plate collectors perform better in high ambient temperature areas, as the back heat loss from collectors decreases as the ambient temperature increases, while the loss is higher at a low ambient temperature [28]. As opposed to flat plate collectors, where the back heat loss is higher during low ambient temperature, evacuated tube collectors perform better, as the vacuum serves as insulation and retains the captured solar energy in low ambient temperature conditions. This was illustrated by outdoor testing in northern maritime climate [29].

5. Residential Solar Water Heating for Inland

In areas where solar intensity is strong and the share of fossil fuel in primary energy supply is substantial, solar energy has significant bilateral use as a means of energy saving (heating and electrification) and a clean development mechanism (CDM) [29–31]. Due to low solar radiation availability and an extended winter period, solar energy has only been used in Norway for heating purposes as a complement to electric heating, with very little penetration [32]. In a solar heat worldwide report from 2011, solar thermal installation in Norway was estimated at 13 MW_{th} (83% glazed flat plate, 11% unglazed flat plate, and 6% tubular collectors) [8]. Solar collectors of 168 m^2 for Norway's first passive standard building in Bergen and 95 m^2 for the Bjørnveien building in Oslo, which cover 20–25% of the heat demand, are known as large-scale SHW installations in Norway [32]. The market potential for solar thermal systems in Norway is estimated to be between 5 and 25 TWh by 2030 [32]. The considerable gap in estimation is due to future cost uncertainty in conventional energy sources and competitive alternative technologies, while the passive house standard and Enova's support schemes are expected to boost Norway's solar thermal market. More than nine companies have been active in the solar thermal market since 1995, manufacturing, distributing, and installing solar thermal systems. There is no known statistical data regarding solar thermal use in Inland from Statistics Norway, but, based on solar potential assessments, considerable solar energy yield would be possible. Considering Statistics Norway's survey data, Inland energy consumption per household is the highest of all counties in Norway. Hence, as an alternative energy mix and to reduce high-value electricity consumption for heating, solar water heating might be the best solution if it is viable. As of 2011, more than 50% of dwellings in Norway are detached houses, occupied by 60% of the total number of inhabitants with an average floor area of 112 m^2 and 2.5 persons per households [6]. With this consideration for Inland's population, at least 50% of dwellings are suitable for deployment of typical (4 to 6 m^2 and 300 L daily hot water demand) roof-top solar water heaters.

5.1. Inland Solar Potential. Solar energy is the cleanest source of energy and does not contribute to global warming. Depending on the location on the earth's surface and sun-earth relative motion, solar radiation striking the earth's surface continuously varies. The monthly average daily global solar radiation in Norway is modest compared to tropical regions and varies between 0.1 and 0.35 kWh/m^2 during the coldest month, January, and between 4 and 5.5 kWh/m^2 during the peak summer, July, as shown in Figure 1. The annual average daily global solar radiation in Norway is 2.46 kWh/m^2 [32]. Solar intensity is relatively strong in the eastern (mostly Inland) (Inland and Oslo located in Figure 1 show only their relative location, and this does not indicate actual location) and southern parts of Norway. Duffie and Bechman [33] suggest that, for a maximum annual solar energy collection in a given location, the surface inclination angle should be equal to the latitude angle. Whereas, for a maximum summer (April to November) collection, the surface inclination should be 10 to 15° less than the latitude angle, and for winter (December to March) it is found to be 10 to 15° more than the latitude angle.

Annual hourly measured global solar radiation data were obtained only for three populous locations in Inland and the capital Oslo from eklima [34], a web portal for free access to the Norwegian Metrology Institute's database for the years 2005 to 2009. The four sites considered were Østre Toten (60.7°N, 10.87°E, 264 m), Øystre Slidre (61.12°N, 9.06°E, 521 m), Rinksaker (60.77°N, 10.8°E, 264 m), and Oslo (59.9°N, 10.72°E, 94 m). The ultimate goal and intention of the solar potential assessment is to estimate hourly performance of solar water heaters in Inland using SAM. However, SAM

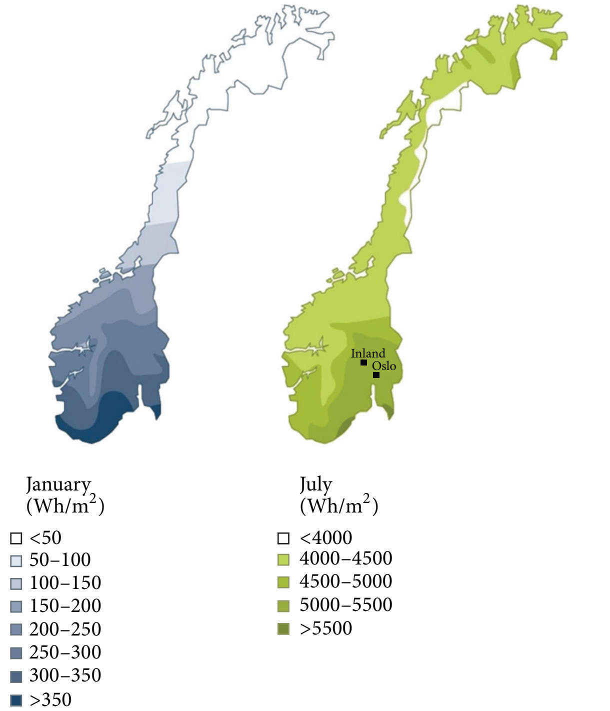

Figure 1: Monthly average daily global solar radiation map of Norway for the months of January and July [Wh/m^2/day] [32].

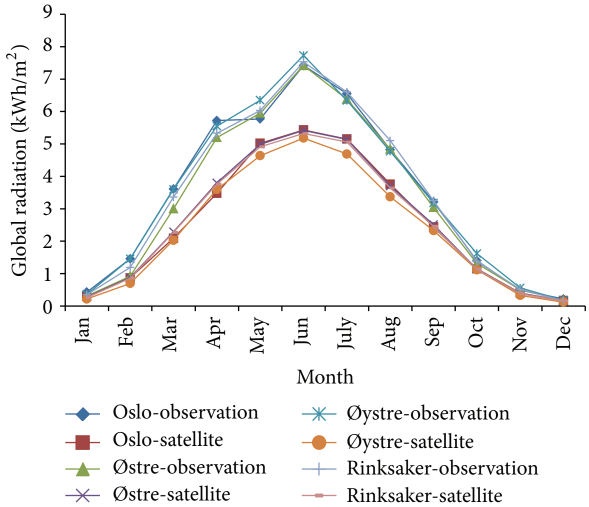

Figure 2: Monthly average observation and satellite-derived daily global solar radiation (kWh/m^2).

uses hourly beam and diffuse radiation as input variables for the simulation, and it was difficult to find these hourly observation data in Norway, as the stations record only global radiation. Therefore, as shown in Figure 2, the consideration is to compare the long-term variation in monthly global solar radiation (observation) between Oslo and Inland (average of the three sites in Inland) and to use Oslo's hourly beam and diffuse radiations (satellite-derived) for SWH simulation in Inland with some correction factor. Oslo is not part of Inland Norway, but it is the only site close to Inland and available with free hourly beam and diffuse radiation (satellite-derived) in Norway.

NASA's surface meteorology, IWEC (International Weather for Energy Calculations), and meteonorm's weather database sites are the most common sources of hourly and monthly solar radiation data for more than 2,100 locations with an 18-year (1986–2005) average [35–37]. The Norwegian Meteorological Institute uses a Kipp and Zonen CM11 pyranometer in all stations to record global solar radiation, which is according to the World Meteorological Organization's guidelines [38].

As shown in Figure 2, considerable variations exist between observation and satellite-derived data (satellite-derived data used here is the average of three sources NASA, IWEC, and meteonorm). However, despite the longitudinal variation, global solar radiation and annual distribution at all sites for both sources of data seem to be attuned, and the deviance range is also insignificant. Root mean square error (RMSE) computed for hourly average annual global radiation deviance between observation and satellite-derived data was found to range between 33% in Oslo and 38% in Øystre.

In this case, the average of Østre, Øystre, and Rinksaker is taken as the Inland average. Hence, based on the observation data, Inland's daily global solar radiation averaged as 3.37 kWh/m^2 while it is 2.48 kWh/m^2 using satellite-derived data, 36% lower than that of observation. At this point, it is difficult to figure out the cause of the data discrepancy between the two sources, as this is outside the scope of this paper. However, based on the literature and previous experimental studies, for standard measurement procedures, hourly average observation data is considered to be more accurate and relevant for time series performance simulations, whereas poor cosine response and reradiation from pyranometers are always susceptible sources of error in global radiation measurement (observation) [34]. However, observation values in Inland can contribute to better understanding and accurate solar potential prediction in Norway, as very few stations record hourly global radiation.

On the other hand, regardless of data source and considerable spatial variation, global daily solar radiation variation in the south-eastern part (Oslo and most of Inland) of Norway is very slight, as shown in Figure 1. The small mean error in long-term monthly global solar radiation between Oslo and Inland shown in Figure 3 could be taken as an indication of invariability. As a result, it is possible to conclude that the annual global solar potential and distribution in Inland are similar to Oslo's. With these considerations, it is reasonable and practical to use Oslo's hourly beam and diffuse radiation to estimate hourly solar collector energy yield in Inland. Had it been possible to get hourly observation data for direct and diffuse components of global radiation in Oslo, it would have been possible to estimate the solar energy yield in observation case. One might think that it is possible to

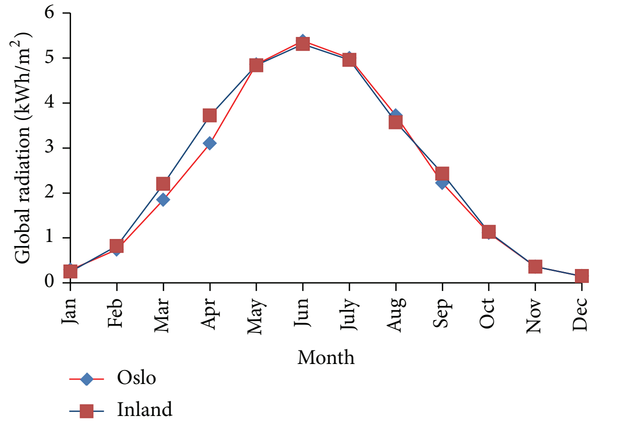

Figure 3: Satellite-derived monthly average daily global solar radiation for Oslo and Inland.

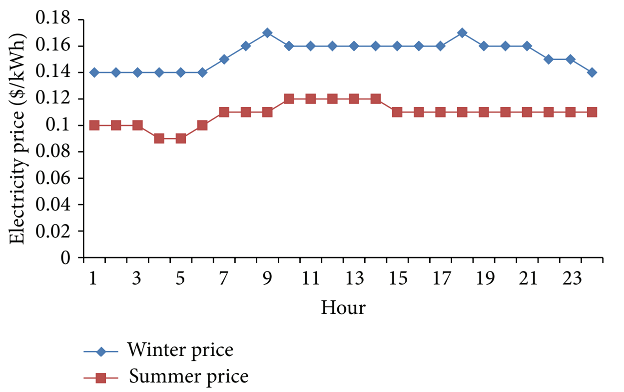

Figure 4: Seasonal hourly electricity price for household (including all fees) [39].

normalize the satellite-derived hourly data over observation, which is true if it is on a horizontal surface, but there is no systematic correlation between diffuse and beam components to estimate total radiation on inclined collector surfaces.

5.2. Model Input Parameters. In addition to solar radiation, electricity price and hot water usage are the main input parameters. As part of the Nord Pool electricity market, the electricity price in Norway is determined by water availability in reservoirs. In the model, the seasonal hourly electricity price is used, as shown in Figure 4. Usually, electricity in summer (from May to September) is cheaper than in winter (from October to April), due to sufficient water supply being available in hydropower dams during summer. The electricity price also varied on a yearly basis. Normally, the Nord Pool electricity market cycled over a single "leap" year (7 years), three wet years, three normal years, and one dry year, where a high electricity price in dry years and a low price in wet years cycled. Since 2010 was a dry year with high electricity prices, 2011 and 2012 were taken as wet years and the average is used for this case study.

Table 2: Collector parameters.

Parameters	AE50 glazed flat	SR30 tubular
Gross area (m^2)	4.66	4.67
Heat gain coefficient ($Fr\tau\alpha$)	0.691	0.419
Heat loss coefficient (FrUL)	3.4	1.5
Incidence angle modifier (IAM) coefficient	0.19	−1.38

Water heating energy demand in Norwegian households ranges between 2.5 and 5 MWh [2]. Considering the average 3.75 MWh, equivalent daily hot water demand at 45°C was estimated to be 250 L using SAM. Hot water storage temperature is assumed to be 45°C. The hourly hot water demand distribution profile is adopted from an extensive field measurement study in the UK [40]. The measurements were made in 120 dwellings. For our case study, the normalized average hourly load profile was adopted merely to serve as a model for Inland Norway. In this work, two types of solar water heating models were considered, namely, glazed flat plate and tubular collectors. Two models with the same system components and different collector specifications with series of collector areas from the SAM database were chosen: alternate energy AE glazed flat plate collector 2.6, 3.7, 4.66, and 5.18 m^2 and suntask SR tubular collector 1.59, 2.32, 3.07, and 4.67 m^2. The collector specification for 4.67 m^2 is shown in Table 2 and is based on the Solar Rating and Certification Corporation's (SRCC) performance rating [41]. The models are chosen based on gross collector area for rooftop installation. The SAM solar water heater model works on a two-tank system, main and auxiliary tank. We assume storage tank capacity to be 250 L and auxiliary heater capacity to be 4.5 kW for our case study. We assume an electric water heater energy factor (overall heating efficiency) of 90%. The circulation pump power consumption is 40 W for both solar loop and storage loop and is regarded as a loss. The storage is assumed to be placed inside a room where the mean ambient air temperature is 20°C. SAM considers the storage tank as a two-node stratified tank to estimate the heat loss. The optimal collector tilt (the handbook of photovoltaic science and engineering [42, p. 942] suggests a linear approximation to estimate the optimal tilt angle at a given location as $3.7 + 0.69 * \o$, where $\o$ is the latitude angle (°)) (45°) in the northern hemisphere and heat exchanger efficiency (85%) are optimistically assumed values. Solar radiation transmittance in transverse direction for tubular collectors are accounted in SAM by an incidence angle modifier. The working fluid in the solar collector loop is assumed to be glycol (Cp = 3.4 kJ/kg-°C). SAM uses the annual and monthly average ambient temperature to estimate the sinusoidal hourly mains (cold water) temperature [43].

Investment costs from two sources for each type of collectors were considered for demonstration based on previously studied SWH projects from RET (RET screen is clean energy project analysis tool) Screen International's project

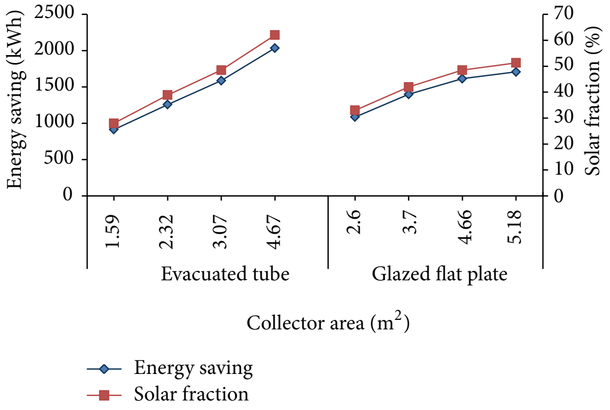

FIGURE 5: Annual auxiliary energy saving and solar fraction for each type of collectors.

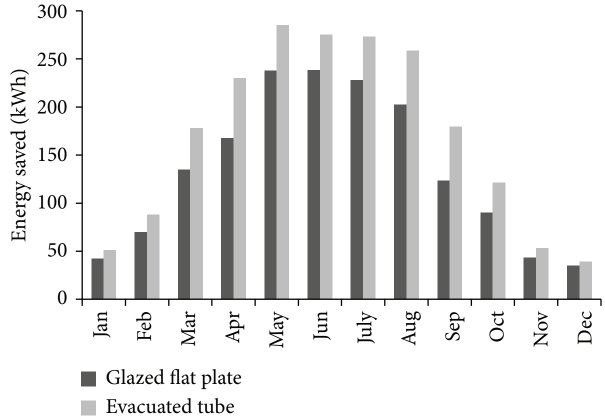

FIGURE 6: Monthly auxiliary (electric) energy saving for 4.66 m^2 collector area for each type of collectors.

database [44] at 593 and 680 $/m^2 for flat plate and tubular, respectively. The Norwegian Energy and Water Resource Directorate's (NVE) (detailed investment cost analysis based on actual price from suppliers for hydropower, wind power, district heating, and solar water heating was done by NVE in 2011 [45]) SWH cost summary report is the other source, where the figures are estimated to be 700 and 850 $/m^2 for flat plate and tubular collectors, respectively. A fixed annual operation and maintenance cost of $30 is also assumed. Economic parameters considered for the financial analysis were 3% inflation rate, 6% discount rate, 5% electricity price escalation rate, and 25 years project life time. The investment is assumed to be self-financed without loan.

5.3. System Performance and Viability. Solar fraction is a parameter used to show the contribution of SWH in annual energy demand, expressed as a percentage. 100% means all demand supplied by SWH, while 0% means that all demand is met by the auxiliary electric heater. With this understanding, based on typical household annual water heating energy demand 5 MWh, hourly simulation result showed that tubular collectors have better solar fraction and energy saving than flat plate collector for the series of collector areas shown in Figure 5. Tubular collectors' SWH system response in energy saving and solar fraction for collector area is steeper, while that of flat plates tends to be flatter. This is due to the fact that tubular collectors have better efficiency in cloudy and low-temperature areas. In fact, theoretically flat plate collectors show higher efficiency during the summer season when the ambient temperature and solar radiation are high, but in a country like Norway, where the annual solar intensity and ambient temperature are reasonably low, convective and conductive back heat loss from flat plate collectors is quite high as opposed to tubular collector, where the vacuum retains the useful heat gain. The monthly energy saving results shown in Figure 6 for the typical collector gross area 4.66 m^2 revealed that tubular collectors save significant amounts of electric energy during the summer, from April to September, where the solar intensity is relatively strong with better extended day time availability (longer sunshine hours).

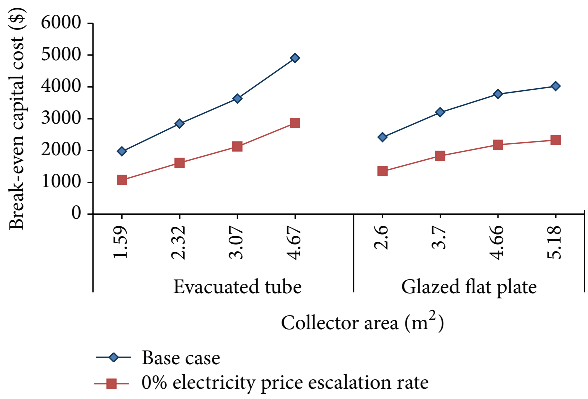

FIGURE 7: Break-even capital cost sensitivity for electricity price.

In technoeconomic assessments, the choice between energy saving solutions should be based on comparative life cycle cost (LCC) [21, 46]. Break-even occurs when the LCC of electric bill saving offsets the LCC of SWH. Break-even is therefore a "no-profit and no-loss" point and is expressed in years over the project's life time. The fewer the years to break-even, the more attractive the SWH solution and the higher the cost saving over the project's life time. Net present value (NPV) is total cost saving over the project life time, and it is zero at break-even point. With these understandings, it is worth estimating that the investment cost frontier is equivalent to zero NPV, and this cost is referred to as the break-even cost in this paper. This is done in SAM by continuously changing the investment cost until the NPV comes to zero for each case. All SWH investment costs below break-even cost would be viable. Break-even cost generally increases with collector area for both collector types, as shown in Figure 7, but as with energy saving, it is steeper in the case of tubular collectors. Using a larger size for the same annual demand would increase energy saving and profitability. For example, in the case of the 4.66 m^2 tubular collector, investment costs below $4,903 are viable, and the system cost below this would be higher in terms

Table 3: Annual energy savings and economic attributes.

Output parameters	Base case-no incentive		Scenario case-20% incentive	
	Flat plate	Tubular	Flat plate	Tubular
Solar fraction (%)	48	62	48	62
Energy saving (kWh)	1614	2035	1614	2035
Net present value ($)	512	914	1164	1707
Payback period (year)	11.51	11	9.9	9.46
IRR (%)	7.26	7.85	9.31	10

of profitability or high NPV, whereas for similar collector areas flat plate collectors' break-even cost is estimated at $3,774, meaning that, to achieve the same energy saving bill, the 4.66 m^2 flat plate collector's investment cost should be $1,129 lower than that of the 4.66 m^2 tubular collector. A showing case for comparison using the investment cost from NVE is used to demonstrate technoeconomic attributes, as shown in Table 3. The higher cost range of NVE, 850 $/$m^2$ for tubular and 700 $/$m^2$ for flat plate, was compared with the break-even cost of the 4.66 m^2 collector area. From Figure 7, the break-even cost for tubular and flat plate is found to be 1,049 $/$m^2$ and 809 $/$m^2$, respectively. This implies that, based on NVE investment cost estimation, both systems are viable. In either case, deployment of typical SWH could give a substantial reduction in the amount of electric energy, as shown in Table 3. Tubular collectors would be more economic and applicable with better energy saving in terms of both net present value (NPV) and payback period. Moreover, SWH investment is sensitive to initial investment cost; considering the Norwegian government's 20% investment cost subsidy as an incentive for SWH deployment, it was shown that NPV increases by 127% for flat plate and by 86% for tubular collectors with shorter payback period. Hence, increasing the subsidy would reduce risk as regards investment return, strengthen public trust, and motivate more people to use SWH.

As Figure 5 depicted, for a given solar fraction or energy saving, one can draw a horizontal line that intersects with both curves and observe that tubular collectors could supply the required energy at reduced collector area. Coupled with this, despite the high investment cost in the case of tubular collectors, both types of collectors have comparably similar payback periods as shown in Table 3. Meaning that the energy saving and hence operation cost saving were high enough to pay back the investment cost as low as that of flat plate collectors. Similarly comparing the break-even capital cost for increased collector area, tubular collectors have higher break-even cost than flat plate collectors as shown in Figure 7. For example, to acquire the same break-even capital cost of $3,000, the flat plate collector area should be 46% higher than that of tubular collector, which corresponds to 2.32 m^2 for tubular and 3.4 m^2 for flat plate as shown in Figure 7.

Internal rate of return (IRR) is the discount rate which gives zero NPV. In essence, a project is viable if IRR is greater than the discount rate used, and a project with high IRR is always a priority. With this understanding, IRR for the base case (no incentive) is estimated as 7.85% for tubular collector as shown in Table 3 and increases to 10% for 20% state investment cost subsidy. This showed that, apart from short payback period and high NPV, the subsidy substantially increases the IRR of the investment. It is apparent that subsidizing SWH investment cost aims to promote and boost the SWH market in such a way as to decrease the market price and make it self-sustained.

From direct emission reduction perspectives, tubular collectors contribution is more than flat plate collectors, as it is proportional to the electricity saving. However, a life cycle environmental impact assessment study based on the UK perspectives revealed that flat plate collectors have marginal benefits (7%) over tubular collectors [15]. This is due to the fact that tubular collectors manufacturing process is energy intensive (77.7 MJ/m^2) as compared to flat plate collectors (4.18 MJ/m^2), but in a region like Inland where the source of electricity is 100% renewable, it is reasonable to assume that the life cycle environmental impact of tubular collector is lower than that of flat plate.

5.4. Sensitivity Analysis. It is worth testing the system for sensitivity of susceptible financial and technical parameters. But it is apparent from the technical analysis that in a given location the solar fraction would increase if either hot water usage at low temperature increases or hot water demand decreases. In this case, the measured solar potential from eklima (see Section 4) is higher than that used in this study. Hence, the solar fraction in the case in question would obviously increase. It is very important to consider the SWH investment cost for electricity price sensitivity, so as to determine the size of investment return. The base case assumption was 5% electricity escalation rate, which is a reasonably low limit of historical electricity price escalation rates in Norway. Over the last decade, electricity prices in Norway have increased by an average of 8% [6] and are expected to continue to increase despite various speculations regarding future electricity prices forecast as a consequence of the quota scheme additional green electricity charge [3]. Break-even cost is highly sensitive to electricity price variation. As shown in Figure 7, in a 0% escalation rate scenario, there is considerable variation with that of the base case and increases with collector area. This is due to the fact that most of the costs associated with electric energy saving are the future cost components, which are therefore more affected by the electricity price. A high electricity price favors SWH deployment and vice versa.

6. Discussion

It is clear from the technoeconomic assessment of tubular and glazed flat plate collectors in Inland's specific case that tubular collectors are more advantageous from an economic point of view than flat plates. But it should be noted that, for other locations, the result might be different as it depends largely on solar resource availability and ambient air temperature. The existing energy system's electricity saving for integration of solar heating system in Inland is worth estimating. For the typical 4.66 m^2 tubular collector roof-top installation, it was possible to reduce the electric energy used in a single household by up to 2 MWh. In this case, assuming deployment of typical tubular solar water heating systems in all detached dwellings (60% of dwellings)m with 2.5 occupants in each dwelling for a total of 374,359 inhabitants in Inland, the total annual electric energy saving would be 182 GWh. This is equivalent to a reduction of 15,690 tonnes of oil energy and 48.6 $ktCO_2$ emissions [8]. With this, deployment of SWHs in Inland could increase the share of renewables in primary energy supply, reduce high value electric energy from existing electricity-intensive heating systems, and make a substantial contribution to global emission reduction.

The results show that significant electricity savings would be possible as a result of distributed small-scale economic energy conservation measures, for example, solar water heaters. Further, moderate solar potential, SWH large-scale installation profitability [31], and on-ground energy policy are key motivators for deploying of large-scale solar thermal systems in Inland. A demonstration case of the Taiwanese government's incentive program for deployment of SWHs, which ran in two packages, 1986–1991 and 2000–2004, resulted in tremendous socioeconomic development, through energy saving, market development, and job opportunities [47]. In countries like Norway, where solar thermal experience is almost nonexistent, apart from the targeted grant and tax incentives, promotional tools would make a substantial contribution to solar thermal market penetration, until the market becomes self-governing. Most G-20 countries have been using grant and/or tax incentives as a promotional tool for renewable-based heat production, including solar thermal [9]. With this result, in Spain low-temperature solar thermal installation increased by 330% for the period 1999–2008 and declined by 40% after the economic crises in Europe in 2008. In terms of viability, Inland's low population density is considered to be the main challenge when it comes to connecting households with large-scale district heating systems. But it is plausible to supply households from small-scale district heating systems here and there, whereby solar thermal could have a significant share, as in other Nordic countries with comparable solar potential, that is, Denmark, Sweden, and Finland [8].

Homeowners usually focus on investment cost, not operating costs, and they want to be paid back in the shortest time possible for any investment they make. Hence, increasing the subsidy not only reduces investment cost but also shortens the payback period and increases future cost savings, and the SWH solution would be more attractive, whereas the prosperous life in Scandinavian countries and the "able to pay" financial freedom for high electricity prices are perceived by the author to be the major barrier to SWH diffusion in Norway. Electric heaters are easy to use and have a less complicated system and better aesthetic value than SWHs. In this case, the subsidy alone might not be as efficient as desired for SWH diffusion in the community as a whole, beyond small target groups. But it has massive implications for behavioural change.

Extrinsic and intrinsic motivations are important behavioural tools for changing public awareness towards use of SWH. People are extrinsically motivated for the sake of achievement or winning in competition with others and intrinsically for personal enjoyment and comfort [2]. Once motivation has been created in groups of SWH users through subsidy, it will not end up with them; rather, the displayed SWHs induce extrinsic motivation in nearby neighbors and diffuse through the community as a whole. A demonstration case for high penetration in the Toyota Prius hybrid car's market in the USA is a good example of SWH promotion [2, 48]. Despite the fact that many high-performance hybrids cars are available on the market, the Toyota Prius was designed in such a way as to preach and reflect one's environmental awareness easily. As a result, people were extrinsically motivated to buy a Toyota Prius and show that they cared for environment. Households who do not have SWH on their roof-top might feel that they are not eco-friendly and are extrinsically motivated to install SWH. This in turn increases market volume and ultimately the SWH market becomes self-sustained with high penetration.

7. Conclusion

With modest solar radiation availability, solar water heating with auxiliary electric heating for residential application is found to be viable in Inland. Generally speaking, for a given energy demand in Inland, tubular collectors are better than flat plates in terms of performance and cost. Moreover, within a tubular SWH system, for the same energy demand larger collector sizes are better, as long as enough space is available for installation. As discussed in Section 5.1, solar radiation in southern and south-eastern Norway is comparably stronger than Inland and would result in better solar fraction than Inland. A government subsidy package for deployment of SWH as a complement to existing electric-intensive heating systems would boost the benefit and stretch the market for large-scale solar thermal installation. Further integration of SWHs in line with the government policy for bioenergy and heat pumps penetration for domestic and industrial application in Norway could increase the share of renewables in the primary energy supply and create flexibility in the energy mix at national level. In doing so, strategic advocacy towards energy efficiency in society would build adaptability and trust for SWH penetration in the region and ultimately long-term behavioral change in society towards use of SWH could be envisioned. Lastly, it would be interesting to validate the simulation results through outdoor testing or field measurement, and the authors recommend this as future work.

Conflict of Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

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Paper II

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Towards a flexible energy system – A case study for Inland Norway

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HIGHLIGHTS

- The Inland Norway energy system is built and validated using EnergyPLAN tool.
- Heat pump and bio-heating as a replacement for direct electric heaters would create a flexible energy system.
- Wind energy integration in Inland Norway reduces imports of electricity during peak demand periods in winter.

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ABSTRACT

This paper analyze the benefits of the use of bioenergy, solar thermal and wind energy in a flexible energy system to increase the share of renewable sources (RES) in primary energy supply, reduce primary energy consumption (PEC) and ensure power supply security in Inland Norway, and Norway at large. Firstly, the Inland reference energy system was built and validated using the EnergyPLAN system analysis tool based on the year 2009. Two alternative systems (scenarios), mainly of bio-heat and heat pumps in individual and district heating systems were then constructed and compared with the reference system using EnergyPLAN. The quality of a given energy system can be best described by its PEC, RES, emission levels and socio-economic costs. The result shows that it is plausible to improve the quality of the Inland energy system by optimal resource assortment in the energy mix. Integrated use of bio-heat and heat pumps in individual and district heating systems, as a replacement for direct electric heaters would reduce PEC and socio-economic costs considerably more than intensive bio-heating deployment alone, thereby increasing total domestic green electricity generation. The ability to integrate wind power and its value in the Inland energy system is more reflected by reducing imports of electricity during peak demand periods in winter, as wind power availability in the region is significant as opposed to the low precipitation during these periods. In addition, increasing wind energy penetration helps to limit biomass consumption in a district heating system built on heat pumps and bio-heat boilers.

1. Introduction

Climate change awareness campaigns during the last two decades motivated governments to implement new polices and strategies for greater use of non-fossil resources by increasing the share of renewables in their primary energy supply for the betterment of society and sustainable development. The ultimate 'renewability' will be achieved when the total renewable production and total energy use becomes self-balanced. Integrated use of limited renewable resources would play a vital role in increasing the share, supply and penetration of renewables in the current fossil fuel intensive energy system. To this end, it is only in a flexible energy system that high penetration of fluctuating renewables, like wind and solar power could be plausible and viable [1].

Norway's domestic energy use comprises 7% bioenergy, 51% electricity and 42% fossil fuel (mainly for transport) [2]. Electricity generation by source stands, 95.2% hydropower, 3.8% thermal and 1% wind power, as of 2011 [3]. As opposed to other Nordic countries, the electricity and heat sectors in Norway are 'monopolized' by hydroelectricity. The share of electricity use for heating in household sector is 65%, while in the service sector it accounts for 38% of its total energy use [4]. Direct electric heating has been used extensively by households; only 18.5% of households used a heat pump in 2009 [5].

Norway is a country endowed with renewable resources, especially high flows of water. Following its high market stabilization share with cheap hydroelectricity, Norway has been considered

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to be a 'hydro-electricity tower' in the Nordic electricity market and the EU has a regional plan to store fluctuating power in Norwegian reservoir (using pumped storage system), to serve as a 'green battery' for the European Union's (EU) renewable energy target [6]. Of the national hydropower potential 214 TW h, 60% has been developed, 20% is planned for small-scale development and the remaining 20% is permanently protected [3]. On the other hand, the high dependency on hydropower makes Norway extremely vulnerable to low precipitation and forces the country to import expensive electricity from the thermal power dominated European electricity market during dry seasons. To this end, the Norwegian energy policy has put policies in place for promoting energy efficiency, increased use of waterborne heating, and wind power development to complement hydropower [3].

Wind power development is showing significant progress compared to the past with 1.1% penetration in 2012, while the total potential is estimated to be 3.5 PW h[1] [7]. Following the limited explorable hydropower potential availability, several wind power projects are under development at potential sites. By 2020, it is expected that the total installed wind power will reach 3000–3500 MW and annual production 6–8 TW h [8]. All in all, the aggressive wind power development in the years to come, is part of the vision set for production of 13 new TW h green electricity by 2020, as set by the Norway–Sweden green electricity certificate market [9].

Solar thermal use in Norway is in its infancy and is mainly a complement to electric water heating. As of 2011, total installed capacity was 13 MW_{th}, equivalent to 752 tons of oil energy saving and a 2.3 $MtCO_2$ emission reduction [10]. The market potential for solar thermal systems in Norway estimated to be between 5 and 25 TW h by 2030. The considerable gap in estimation is due to future cost uncertainty regarding conventional energy sources and competitive alternative technologies [11].

Bioenergy use in Norway accounts for 6–8%, mainly as firewood in households space heating and waste, forest industry residue and agricultural residue in industries [2]. Together with the national incentive programme through Enova, there is a national target of 14 TW h bioenergy and a 67.5% renewables share in the primary energy supply by 2020, while the estimated total sustainable bioenergy potential in Norway is 39 TW h, three times larger than today's use [2]. This will be achieved mainly through district heating development, as the emerging district heating market in Norway uses mainly woody biomass and waste as its fuel source [12,13]. So far, district heating in Norway is in its infancy with only 6% market penetration, while the share is 55% in Sweden, 47% in Denmark, 49% in Finland and 92% in Iceland [14]. In Norway, of the total 10 PJ district heat energy sold in 2009, the service sector consumed 69%, residential 20% and industry 10% [15]. The low market share in the residential sector is due to the small share of multi-dwelling buildings in this sector. More than 50% of Norway's inhabitants live in detached houses [5], which make distribution costs high and hamper district heating's competitiveness with other solutions. To this end, integrated small-scale district heating system with individual heat pumps in sparsely populated areas could be a systematic approach to challenge the costs associated with distribution.

This paper examines two cases: Electric energy is 100% exergy, and high quality energy should be used for electric-specific consumption rather than direct electric heating or its value should be amplified (as in heat pumps). Hence, a few possible scenarios are discussed in the light of a shift from direct electric heating to waterborne heating, whereby the extent of achieving reduced imports and increased net exportable green electricity is determined. Secondly, the role of integrated use of bioenergy, wind power and solar thermal in a flexible energy system to achieve the Norwegian energy policy obligation (reduce primary energy consumption, increase the share of renewables in the primary energy supply and reduce carbon emissions) is discussed.

To the best of our knowledge there have been limited system studies with large capacities of inter-connected renewable technologies in Norway that deal with the entire energy system (electricity, heating and the transport sector). The effect of climate change on the energy system [16] and the impact of future energy demand on renewable production in Norway [17] are the main aspects. With large floor areas, households in Inland Norway are the highest energy consumers in the country. Therefore, this paper deals with modeling the energy system and integrating more renewable energy sources in the existing energy mix in Inland,[2] to analyze its contribution for improved electricity imbalance, reduction in total energy consumption, and increased renewable fraction in the primary energy supply. The paper is organized into 7 sections. The first section provides background information about the current energy system. Section 2 briefly discusses the methodology followed and presents the modeling tool used for the analysis based on structure, purpose and function. Section 3 briefly describes Inland's energy use by sector and the entire system description. Section 4 presents modeling and validation of the reference energy system using EnergyPLAN. Section 5 discusses scenario-building for a flexible system study. Section 6 discusses results and findings, followed by conclusions in Section 7.

2. Methodology

As indicated in the introduction, this paper models Inland's reference energy system to further analyze system integration with more penetration of wind, bioenergy and solar, aiming to lighten the strong electric-heat bondage. This section outlines the tool used to model the reference energy system, assumptions and data sources used in constructing the model and scenario-building for further analysis.

2.1. Tool selection

The EnergyPLAN tool was chosen for this study in consideration of its purpose and suitability. EnergyPLAN is a comprehensive tool used to model regional and national energy systems. The model was first developed at Aalborg University in Denmark and distributed free of charge [18]. Detailed documentation and free downloads are available at www.energyplan.eu. EnergyPLAN has been used for various system studies at national and regional level in for example like Denmark, Ireland, Macedonia, Island of Mljet and others [19–22,18,23,24]. It is a deterministic input/output model which consist of the three sectors (electricity, heat and transport) as shown in Fig. 1 and run hourly to optimize system operation. The inputs are power plants' capacity, production and distribution, and electricity and heat demand and the outputs are energy balance in the primary energy supply (PES), share of renewable energy sources (RES), emissions, import–export electricity imbalance and critical excess electricity production (CEEP). EnergyPLAN has technical and market optimization regulations. The technical regulation strategies determine how excess electricity and fuel consumption are reduced, while the market regulation seeks to optimize plant operation based on business-economic marginal production costs. The user can choose either Regulation-1: Balancing hourly heat demand only or Regulation-2: Balancing both electricity and heat hourly demand over a year for

[1] The potential was estimated with the assumption of 8 MW/km^2 wind power development density.

[2] In this paper wherever stated Inland, it refers Inland Norway of Oppland and Hedmark counties.

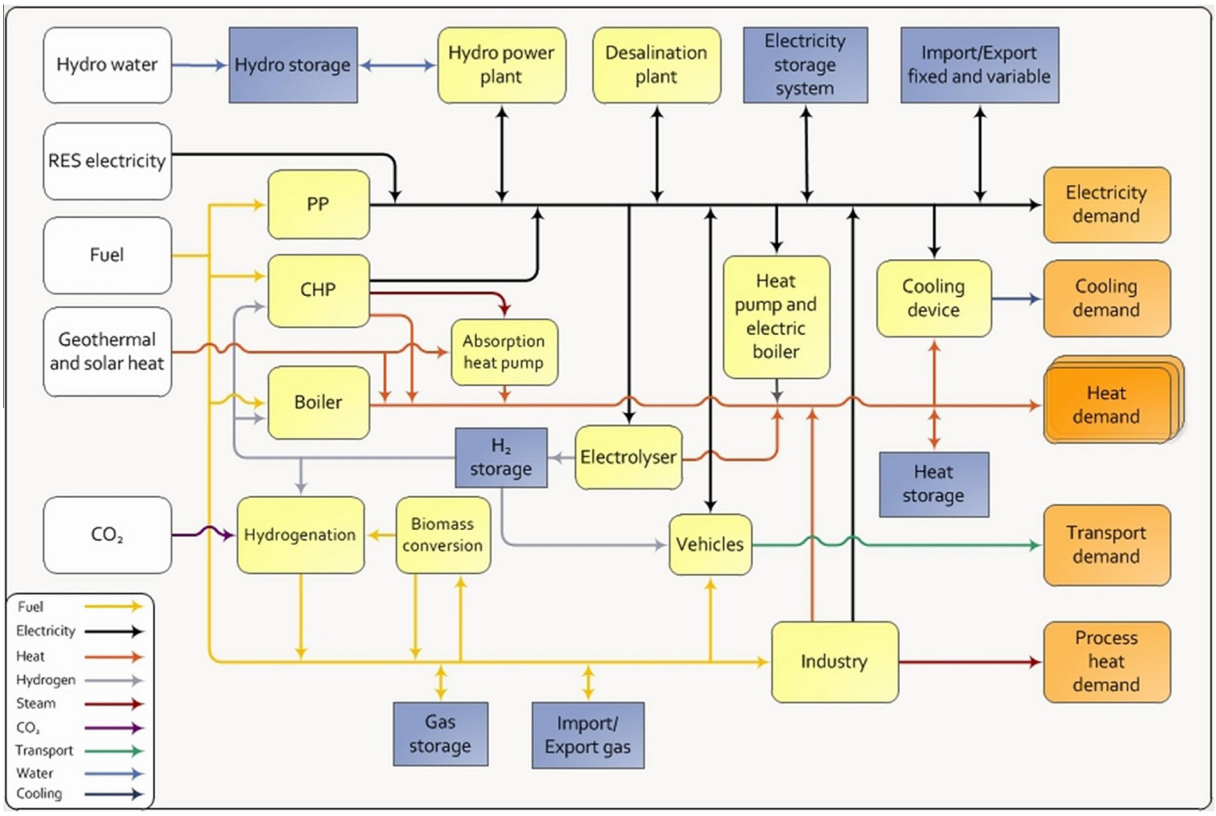

Fig. 1. Schematic diagram and illustration of the EnergyPLAN 11.0 tool [49].

technical optimization. In Regulation-1, all heat producing units are set to produce heat according to the heat demand, and inherently the model is set to prioritize the units in the order of solar thermal, industrial waste heat, combine heat and power (CHP), heat pumps and peak load boilers. Whereas, in Regulation-2, all heat producing units are prioritized in the same way as Regulation-1, but export of electricity is minimized using heat pumps in CHP plants. Heat pumps use excess electricity and dispatch more heat whereby the heat and electricity production from CHP plant is minimized. Basically, the regulations focus on CHP units operation. In a system without CHP units, all heat producing units follow the heat demand and all power producing plants follow the electricity demand if either of the regulations is chosen. Hence, for this analysis, a closed system for Inland with Regulation-1 is chosen, as CHP units are not included in this study. In this case study, the analyses is based on island mode, as the aim is to balance the system internally for optimal resource utilization and maximal domestic electricity production. Further, CEEP regulations are not applied for the same reason, as this would cut back the electricity imbalance.

2.2. Data source and assumptions

The reference energy system model was constructed based on 2009 figures from statistics Norway. Inland's energy consumption by sector is shown in Section 3 (Table 2). Hydropower installed capacity, annual production, plant type, storage size, and annual water inflow data were obtained from NVE (the Norwegian water resource and energy directorate) [3] and Ref. [25]. The main input data in EnergyPLAN are installed capacity and annual hourly production distribution data. Since there is no district heating demand distribution data for the reference year, average annual hourly district heating demand distribution was constructed based on eighteen locations' heating degree day (HDD) in Inland. The duration curve was then corrected for solar radiation effect during the summer season using the sol–air temperature concept [26], as passive heating in summer is usually sufficient to offset space heating demand. The same is done for wind power, where annual hourly wind power production is estimated using hourly wind speed data from three locations in Inland [27] and the 1.65 MW Vestas V82 wind turbine performance curve [28].

Investment, operation and maintenance costs of the wind power and hydro power plants are from Ref. [29], as shown in Table 1, while for Heating plants in individual and district heating is taken from Ref. [30]. Fuel costs are from Ref. [31], as 13.2, 14 and 8.0 €/GJ for diesel, petrol and biomass (woody), respectively. Additional low and high case biomass prices for the sensitivity analysis are assumed at 6 and 10 €/GJ. The CO_2 emission quota price is assumed to be 25 €/ton. For import–export electricity cost estimation, wet (2007), normal (2009) and dry year (2010)[3] average prices in the Nordic electricity market found from Ref. [32], are assumed to be 25, 35 and 53 €/MW h, respectively. In this paper, an interest rate of 3% is assumed for all cases, and the currency used is Euro (€). A recent currency exchange rate of 0.125 is used for NOK (Norwegian kroner) to euro in Ref. [29].

2.3. Scenario building

Scenarios were developed to see the degree of system response for different energy solutions that are well proven solutions and perceived to introduce great flexibility in the system operation. In each scenario, mainly the use of biomass resources and heat

[3] Depending on water availability in reservoirs (mainly in Norway), the market price classified as wet, normal and dry year. High precipitation year termed as wet year (low price), while low precipitation as dry year (high price).

Table 1
Cost of electric power plants and heating technologies.

Technology	Investment (M€/MW)	Variable O&M (M€/MW h)	Fixed O&M (% of inv.)	Lifetime (year)	Ref.
Power plants					
Hydro power	2.5		1	40	[29]
Onshore wind power	1.6		3	20	[29]
Individual heating[a]					
Heat pump-Ground source	1.7		1	20	[30]
Heat pump-Air source	0.9		1.5	20	[30]
Bio-heat boiler	0.68		1	20	[30]
Electric heating	0.8		1	30	[30]
Solar thermal[b]	1200		1	30	[29]
District heating					
Heat pump	1.7	0.27	0.2	20	[31,30]
Bio-heat boiler	0.68	0.15	3	20	[31,30]

[a] All heating plants investment cost is given as (M€/MW_{th}).
[b] Investment cost is given as (M€/TW h).

pumps in district and individual heating were emphasized, aiming at a shift from direct electric heating to waterborne heating systems. Wind power was introduced in the system to note down the electricity imbalance (import–export) that would occur, especially in winter and summer. Details of the scenarios and discussions are presented in Section 5.

3. Inland energy system

Norway comprises nineteen regional counties. Oppland and Hedmark are the two counties located in the east of Norway with a total population of 374,359 living on 52,590 km^2 land area [5] and that constitute Inland Norway. The population density in urban settlements is 982 inhabitants per km^2, below the national average of 1633 per km^2 in urban settlements. This makes Inland known for its substantial forest-based biomass resources [33]. Inland households' energy consumption is the highest in the country with 26.6 MW h, due to large floor areas and extremely cold winter in this region [5].

In 2009, Inland's primary energy consumption (PEC), i.e. after import–export correction, was 14.03 TW h, mainly consisting of hydropower electricity and fossil fuel in the transport sector as shown in Table 2. More than 65% of the total primary energy was consumed by the household and transport sectors, indicating the potential growth in the industry and service sectors in the years to come. Electric energy is the most highly used commodity in every sector, mainly for direct electric heating in the household sector. The share of electric energy use in the household, service and industry sectors was 71%, 84%, and 65%, respectively, as shown in Table 2. The national statistics' 2009 report has shown the penetration of heat pumps in the household sector to be only 18.5%. Considering the high energy demand in this region, households should be a key sector to focus on in terms of energy efficiency.

Inland's forest resources are estimated to be 40% of the national potential and so far only 50% is harvested [34]. As opposed to its availability, biomass use in Inland is modest, mainly as firewood in households and waste for process heating in industries. The economic forest-based bioenergy potential for heating alone in Inland is estimated to be 2.24 TW h, while consumption was 1 TW h in 2003 [33].

Table 2
Inland energy use by sector in 2009 (TW h) [5].

	Household	Service	Industry	Transport	Total
Biomass	1.04	0.23	0.45		1.72
Fossil fuel	0.18	0.17	0.34	5.06	5.75
Electricity-heating	1.93	0.95			2.88
Electricity-appliances	1.04	1.16	1.47		3.67

Fossil fuel is used mainly in the transport sector and accounts for 70% of the total CO_2 emissions[4] from Inland's energy sector.

Hydropower is the only source of power supply in Inland. Total installed capacity was 2075 MW, of which 985 MW is storage plant and 1090 MW run-of-river plant. In 2009, 9.28 TW h of electricity was generated, of which 5.88 TW h was used for domestic consumption and the remaining 3.4 TW h exported to nearby counties. There is a national plan for development of the remaining 20% hydropower potential on a small-scale. Following this, NVE has made a detailed small-scale hydro-power feasibility study for the entire country and pointed out that 18 TW h could be plausible at an investment cost below 3 NOK (Norwegian kroner)/kW h [35]. The corresponding potential in Inland is estimated to be 396.7 MW/1.65 TW h. Wind power developments in the region is under way. Inland's wind power potential is estimated to be 300 TW h [7]. So far, 571 MW/1.53 TW h onshore wind power projects are being planned and are awaiting licenses from NVE.

There is no known statistical data regarding solar energy use in Inland, but based on solar water heating (SWH) potential assessment by the author in a preceding paper, deployment of SWH in a residential house and in all detached dwellings in Inland could have the potential to save 2.2 MW h and 200 GW h of electric energy, respectively.

In 2009, the heating demand[5] in the household, service and industry sectors was 3.14, 1.59 and 0.96 TW h respectively, as shown in Table 3. Direct electric heaters, central boilers, heat pumps and wood stoves are the main heat suppliers in the household and service sectors [4]. Seven district heating plants are currently in operation in Inland, but as of the reference year 2009, there is no production data available for these plants [3]. Most of the plants are new, except one waste incineration plant in Hamar municipality. NVE has approved more than twenty new plants and plant expansions with an estimated annual production of 0.9 TW h, and most of these plants are planned to use woody biomass for base load and electricity for peak load [3].

The Norwegian geographical electricity bidding area (Elspot) in the Nordic electricity market is divided into five parts: East Norway (NO1), South-west Norway (NO2), Middle Norway (NO3), North Norway (NO4) and West Norway (NO5). Inland is part of NO1, interconnected with a transmission capacity of 1700 MW to

[4] Emission excluding agricultural activities.
[5] Heating demand in all sectors are estimated based on the share of electricity use for heating and with the assumption that, all biomass and oil are used for heating purpose only.

Table 3
Inland heat demand and emission by sector in 2009 [5].

	Household	Service	Industry	Transport	Total
Heat demand (TW h)	3.14	1.59	0.65		5.38
Emission (Mt CO_2)		0.47		1.1	1.57

NO2, 500 MW to NO3, 700 MW to NO5 and 2145 MW on the border with Sweden [32]. Considering Inland's and other counties' borders in East Norway, a total of 2000 MW transmission capacity is assumed to be available and is modeled in the system to identify the import–export congestion.

4. Reference year model validation

The reference data was collected for the year 2009, as this is the most recent data available from Statistics Norway. The reference system appears to be segregated with not much integration between the heating, electricity and transport sectors, as illustrated by the energy flow diagram in Fig. 2. This is due to the fact that only single-source power supply was used to meet both the electricity demand and a high proportion of the heat demand. The electricity generation and consumption were simulated on an hourly basis over a year. As shown in Fig. 3, the actual and EnergyPLAN model output monthly distribution are almost similar, simulated with 4% Root mean square error (RMSE). Total aggregate annual electricity generation and consumption, fuel consumption and emission are simulated correctly in the model, as shown in Table 4. Import–export data, however, was not found, electricity production is in excess, and the simulation shows an electricity deficit during low precipitation periods and seeks to import 0.68 TW h (10% of the total electricity demand), while exporting 3.4 TW h (36.6% of total production) as excess during high precipitation periods in summer. It is evident that the model displays an accurate representation of Inland's energy system with a small degree of variation. Inland is modeled as a closed system, and once the model had been verified it was able to run alternative systems to analyze the electricity imbalance and system flexibility for integration of bioenergy, wind energy and solar thermal in the reference system.

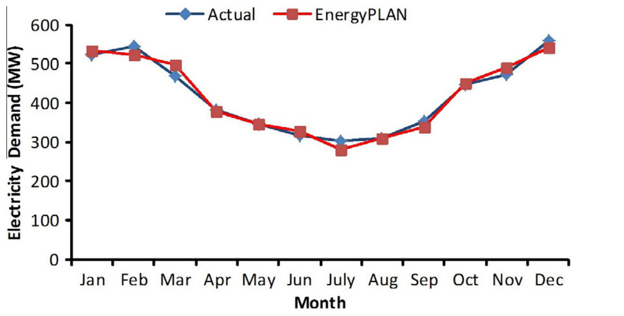

Fig. 3. Comparison of Inland 2009 actual average monthly electricity demand and EnergyPLAN simulated result.

Table 4
Comparison of fuel consumption and electricity production of the reference year to EnergyPLAN simulation.

	EnergyPLAN	Actual	Difference
Fuel consumption (TW h)			
Biomass	1.72	1.72	0.00
Fossil fuel	5.75	5.75	0.00
Emission (Mt CO_2)	1.57	1.57	0.00
Electricity production (TW h)			
Hydro	9.28	9.28	0.00
Excess electricity	2.72	2.73	0.01

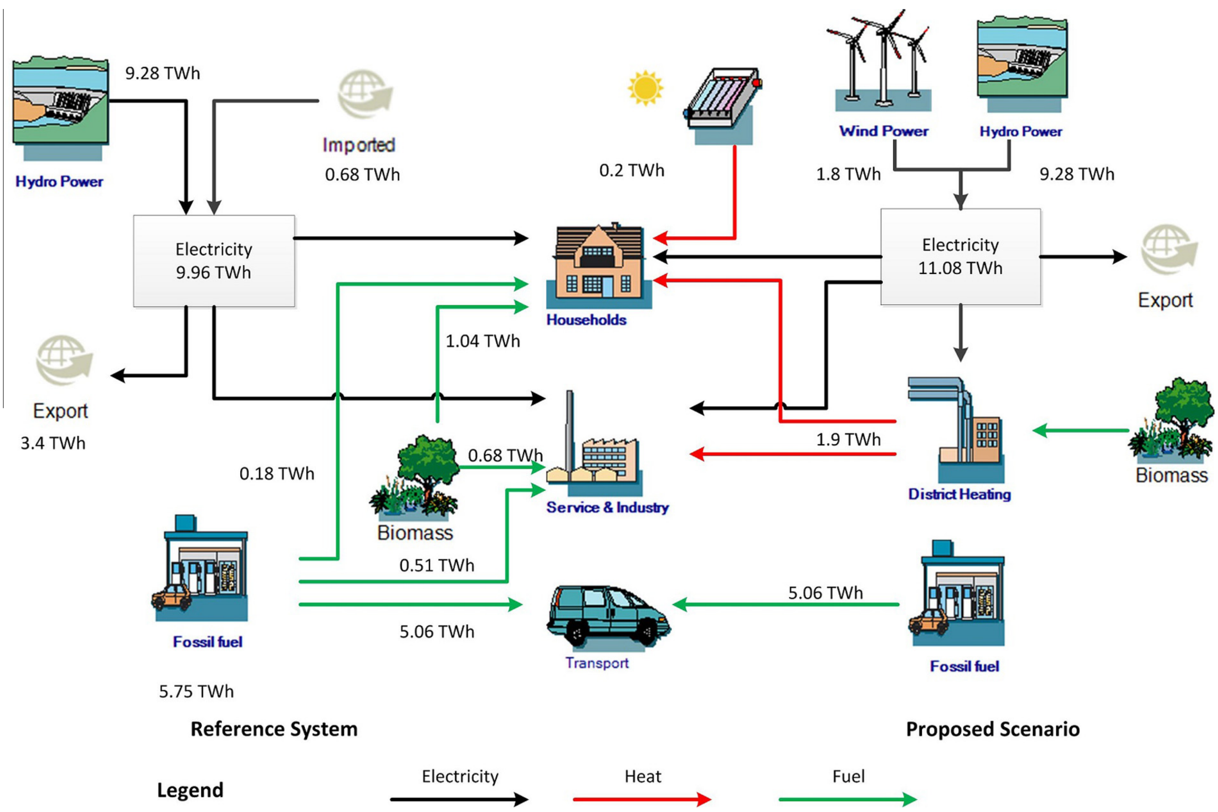

Fig. 2. Inland reference and alternative system energy flow diagram (pictures are credited to ifu Hamburg GmbH).

5. Alternative systems-scenario

It is worth comparing the reference system with more integrated systems in the electricity and heat sectors. Waste heat in incineration plants and woody biomass in bio-heat plants are the main heat sources for Norway's growing district heating sector. In this regard, the scenario-building focused on the use of biomass, solar and wind power in integrated ways with the existing hydroelectricity system, aiming to reduce electricity use in the heating sector and lighten the strong electricity-heat bond shown in Table 2 and Fig. 2. The scenarios are designed in such a way as to reflect the current reality. With the results, successful and weighted scenarios would help to increase public perception and acceptance of new energy systems.

Heat pumps reduce the electricity consumption that would otherwise be used by direct electric heaters. In the reference year, only 18.5% of the households used heat pumps, most of them air source heat pumps used for space heating [5]. Heat pumps working on forced air distribution seem to bring about behavioral change (i.e. in terms of heat pump use) in the community, seeking better comfort, as this type of in situ heat pumps are efficient at speeding up the air circulation and distribution as opposed to hydronic heaters for space heating. As a result, there may be a drift in energy-saving benefits because of elevated comfort set point temperature and poor room temperature control. This was also confirmed by Statistics Norway in its 2009 survey [5] and other studies in Norway [36]. Based on the survey results before and after heat pump installation, electricity consumption in 40% of the households increased while it fell in the remaining 60%. One reason for increased consumption might be reduced firewood consumption but the share is quite small compared to electricity use for heating. This implies that a behavioral change in heat pump use contributes greatly to increased electricity consumption. On the other hand, as opposed to ground source heat pumps, in low temperature regions air source heat pumps have the same low efficiency as direct electric heaters [37]. Use of ground source heat pumps in individual and district heating systems is a well-proven solution for a flexible energy system [31,38–41]. The socio-economic cost competitiveness of heat pumps over the other conventional individual heating technologies is shown in Ref. [38]. A detailed heat pump system description and working principle can be found in Ref. [30]. In this regard, ground source heat pumps with a COP (coefficient of performance) of 3.5 in heating mode were proposed to replace individual and district heat demand which were covered by direct electric heater and air source heat pumps. The maximum share of heat pumps is limited to 50% of the total heat demand at any hour, to keep the desired COP at a low supply temperature. In periods of low wind and hydro-power availability, heat pump dispatch decreases while heat supply continues from storage and vice versa during high electricity production in wind power and hydropower plants, thereby controlling the use of bio-heat boilers.

The existing hydropower installed capacity will continue to provide the ancillary service; this will ensure that system integration is smooth and efficient. The extent of smooth integration of wind energy in a given power system is mainly determined by the type of power plants used. Hydropower systems can absorb more fluctuating renewables than thermal or nuclear plants. But even in thermal plant systems it is plausible to achieve high wind power penetration. The Danish energy system could be a demonstration case. The Danish power system, however, is mainly driven by centralized thermal plants; the system has managed to absorb more than 20% wind penetration in recent decades [42]. In this regard, the hydro-dominated (95%) Norwegian grid can support and absorb a high degree of wind penetration without incurring any financial penalties attributed to additional balancing power demand.

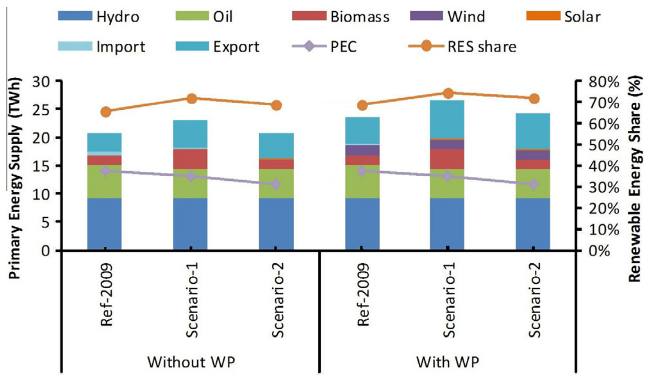

Fig. 4. Total primary energy supply (PES) and renewable energy source (RES) share for each energy system with 700 MW wind power (WP). PEC with wind power (WP) is the same for refe. and scenario-1 cases, but slightly reduced for scenario-2 as compared to without wind power (WP) case.

Considering the above mentioned points, the following alternative scenarios were created for further analysis in succeeding sections of the paper:

Scenario-1:

- Substitute detached households 1.88 TW h heat energy demand with ground source heat pump and solar thermal
- Substitute the remaining multi-dwelling building (terraced houses and flats) households' 1.26 TW h and the service sector's direct and electric boiler 0.64 TW h[6] heat energy demand with a bio-heat (waste and woody biomass) district heating system with heat storage. The capacity of the heat storage is assumed to be 6 GW h, which corresponds to average daily consumption.
- Substitute industry 0.34 TW h and 0.17 TW h service sectors oil-based heat energy demand with bio-heat boilers

Scenario-2:

- Similar to Scenario-1 but the district heating system here is bio-heat boiler and heat pump. Heat pump dispatch for base load, while bio-heat boiler supplies the remaining load.

6. Result

The main results of the alternative scenario's simulation and its comparison with the reference system based on multiple criteria decision are presented in the following sections.

6.1. Scenario comparison

As shown in Fig. 4, the primary energy consumption (PEC) in alternative systems decreased substantially following the high cut-back in electricity consumption by direct electric heaters in the reference system. In the reference year, Inland was a net electricity exporter (2.72 TW h), and the volume of net export continued to increase also in the case of alternative systems- increases of 4.01 and 3.53 TW h for scenario-1 and scenario-2 respectively. This was due to the reduced electricity demand for heating during low precipitation periods in winter. The contribution of the alternative systems for improving electricity imbalance is more pronounced in reducing imported electricity during low precipitation periods. Imported electricity in the Ref. year was 0.68 TW h, while this figure fell to 0.01 TW h and 0.03 TW h in scenario-1

[6] Of the total 0.95 TW h electric energy used for heating in the service sector, heat pumps used 0.31 TW h, and electric boiler and direct electric heaters used 0.64 TW h.

and scenario-2 respectively. In countries like Norway, where most of the heating demand is met by electric heating, it is obvious that the electricity and heat peak demand will coincide and result in large imports of electricity. In this regard, the use of centralized bio-heating and heat pumps would break and shift the coincident peak load occurrence, and in return will be an impulse for flexible hydropower reservoir load management in assuring power supply security. This was illustrated in this paper.

As shown in Fig. 4, PEC declines smoothly from 14.03 TW h to 13.11 in scenario 1, and further to 11.69 TW h in scenario 2. Similarly, the RES share increases to 74.5% and 71.8% for scenario-1 and scenario-2 respectively and shows a significant increase compared to the 67.5% share in the Ref. system. Scenario-1 illustrates the fact that increased use of biomass in waterborne heating will increase the domestic green electricity generation and contribute for a lower PEC. i.e. Biomass consumption was limited to 3.5 TW h, below the available Inland potential 3.74 TW h, whereas, in scenario-2 the PEC and net export were reduced as a result of increased electric consumption in heat pumps in the district heating system. This was because biomass consumption in the bio-heat boiler was limited by the heat pump. Additional flexibility in central plant operation was therefore incorporated.

The use of biomass, however, has to be limited within the available potential, either to keep its renewability or reduce imports of biomass for energy use. To this end, in scenario-2 heat pumps and bio-heat boilers were used as base load and bulk load plants in a district heating system with the result that use of biomass was limited to 1.6 TW h (it was 1.72 TW h in the reference year and 3.5 TW h in scenario-1) by increasing the share of heat pumps in dispatching the heat demand, while the renewables' share still increases to 71.8%. This is due to increased excess electricity consumption in heat pumps. Biomass is a unique resource where use and regeneration rate determine its renewability. Biomass can exist in solid, liquid and gaseous state. Hence, as opposed to other renewables, controlled use of biomass for multiple purposes in the electricity, heat and transport sectors makes it appropriate for energy system integration [43]. With this in mind, the share of heat pumps' and bio-heat boilers' integration in district heating production with 700 MW/1.8 TW h wind power (WP) integration is shown in Fig. 5. For a 25% heat pump capacity share, the total DH production share of the heat pump was 80%, while the remaining 20% is covered by bio-heat boilers. This was achieved with 0.05 TW h imported electricity in the system. With WP, the share of heat pumps in district heating production at 50% capacity share was increased by 7%, while the imported electricity in the system was reduced to 0.01 TW h. But at 25% heat pump capacity share, wind energy utilization is insignificant, as the available excess hydroelectricity was enough to supply the heat pump without

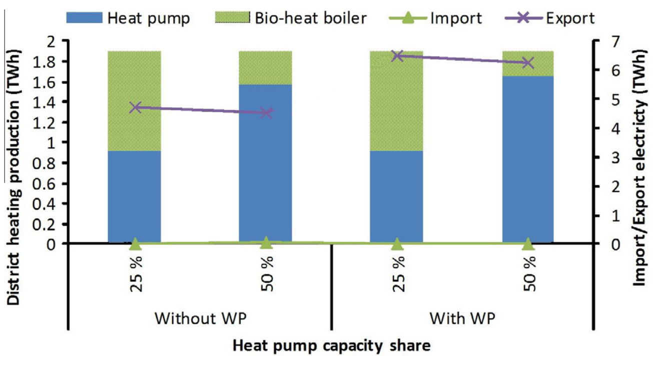

Fig. 5. Heat pump and bio-heat boiler district heating production share for a total installed capacity of 420 MW_{th}. Heat pump at 50% installed capacity share allow the use of excess electricity produced by wind power plant and tends to dispatch more heat with 700 MW wind power (WP).

additional imported electricity. This implies that wind energy is available for use during peak demand periods of winter if a large-scale heat pump installation is incorporated. The role of heat pumps in Inland's energy system and their ability to create a flexible system of reduced PEC can thus be metered by its synchronizing effect between hydropower and wind power, which ultimately contribute to increased water availability in reservoir.

As opposed to solar energy, annual heat demand distribution and wind power availability in Inland are in phase. As illustrated in the weekly electricity imbalance (Fig. 6), wind turbine output during winter is relatively stronger than in summer, and this opens up a space to absorb high wind power generation during peak load times in winter. This was illustrated in Fig. 6 by comparing the reference system with and without wind power and in Fig. 7 by various wind penetration levels. The value of wind energy in a given fossil fuel intensive energy system can be reflected by PES reduction, emissions reduction and power supply security. In Inland's energy system, the value is reflected by reducing imported electricity during low precipitation periods. This was because hydro-electricity production is in excess during high precipitation periods (summer). More than 21% of the yearly wind power production was able to reduce imported electricity in less than 23% of the annual production time (weeks 47–12 in Fig. 6), contributing directly to peak load supply. And also, as shown in Fig. 7 wind energy's contribution to imported electricity reduction was high at low penetration level, then declined after 22% penetration. This implies that wind turbines in this region will have substantial capacity credit[7] at low penetration levels, despite the various speculations concerning wind turbines contribution to peak load supply [44]. Generally, as opposed to hydropower, which varied on a seasonal and a yearly basis, wind power production varied within minutes but remains fairly constant on a yearly basis. With the situation in Inland, wind power could make a substantial contribution to power supply security in Norway at large. In scenario-1, wind power contributes to exportable excess electricity production due to the already peak load shaving taken by energy conservation measures during scenario-building. In scenario-2, however, the district heating central plants seek to utilize wind energy during peak load times in winter as previously shown in Fig. 5.

In Fig. 7 wind power production was varied from 0% to 36% (5.06 TW h) of annual electricity production to see the potential exportable electricity level in each scenario. The maximum technically possible wind power penetration level in the reference system was approximately 27%, while it was 24% for alternative systems. After this point, CEEP[8] increases sharply in both cases, but at a reduced rate in the reference system, as it is still being used to reduce imported electricity in the current electricity intensive system during winter. Similarly, the effect in imports reduction for unit increment in wind penetration becomes insignificant or flatter after 22%, meaning that even though technically 27% penetration level is possible, the optimal amount in Inland for the reference system is 22%. This is because, after a 22% penetration level, a large part of the wind energy production is exported, rather than being used inside the system boundary to reduce imported electricity, and contribute for increased RES share.

From a carbon dioxide emissions perspective, emissions attributed to distributed oil and incomplete wood combustions are already reduced during scenario-building. Since nothing has been done in the transport sector, both scenarios are identical with

[7] Capacity credit is the ability to displace an equivalent amount of 100% firm capacity or contribution for system adequacy [44].

[8] CEEP is the amount of excess electricity produced and neither be used in the energy system nor exported due to transmission capacity limitation. During CEEP conditions, unless the wind turbine reduces production, the transmission system will collapse.

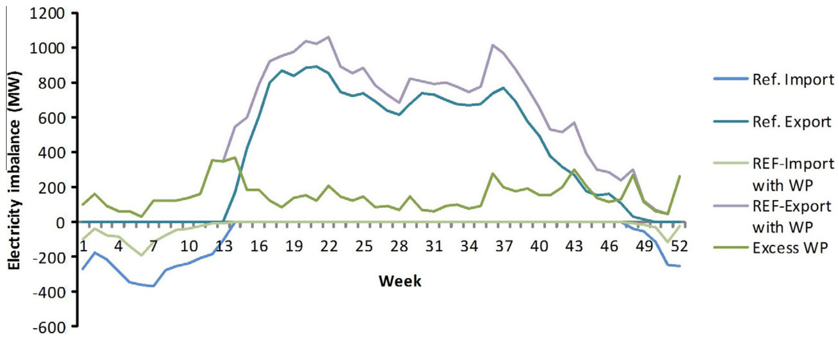

Fig. 6. Weekly electricity imbalance of the reference system with and without 700 MW wind power (WP). Weeks 13–46 are high production time-summer, while 47–12 are high demand time-winter season.

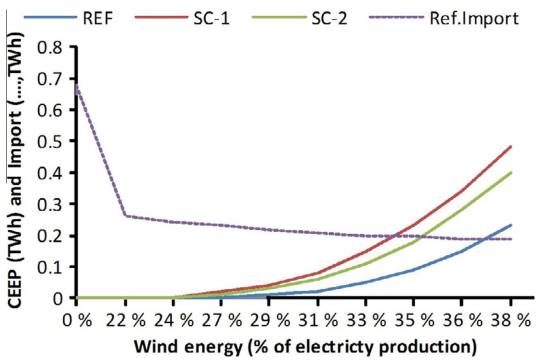

Fig. 7. Critical excess electricity production (CEEP) and Import electricity for increasing wind penetration level in the reference and alternative energy systems.

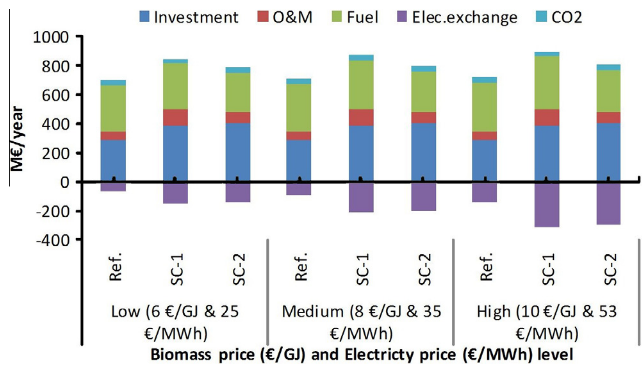

Fig. 8. Annual socio-economic costs (M€) of the reference and alternative energy systems for low, medium and high biomass and electricity price levels.

1.38 Mt per annum, as shown in Table 6 under 'value'. Increasing wind energy will offset global carbon emissions (carbon footprint calculation), but it has no direct impact inside the system boundary, as the major source of emissions is the transport sector. In general, however, the green electricity saving and wind energy integration will contribute to high global emission cut-backs through the Nordic electricity market.

The reference year was regarded as a normal year, and during these periods, Norway is a net importer of electricity [12]. This implies that the result has two implications. Firstly, in an optimal resource assortment which has been used or not at all in an inefficient way at regional level, and secondly to ensure power supply security at national level. As shown in the reference system, a major portion of the heating demand is met by direct electric heaters, meaning that peak electric power and heat demand will coincide. This requires peak load plants and ample transmission line capacity to avoid congestion. In this regard, lightening the strong electricity-heat bond has a socio-economic advantage equivalent to reducing or avoiding construction of new power plants and transmission lines.

Deep in the model, in addition to energy saving measures, the electricity imbalance could be improved by upgrading the existing hydropower turbine capacity, as the existing storage capacity in most of the plants was oversized considering future expansion [25]. It will not increase power production much, but load management and flexibility are of great importance to shift sufficient storage capacity to winter where the demand is peak; thereby providing potential to further improve wind power integration and its capacity credit.

The socio-economic cost result for each system is shown in Fig. 8. In the alternative system case, except for central plant cost, the district heating network cost was not included, as this depends on its size and geospatial condition, making it difficult to make reasonable assumptions. Apart from this, transport, transmission and other infrastructure costs are not included. This implies that the total annual operating costs are hence not absolute costs. However, they can be used to identify and analyze the future cost components of Inland's energy system. The socio-economic cost was compared based on biomass and electricity price levels, described as low, medium and high. Electricity price corresponds to wet, normal and dry year prices in the Nordic electricity market. It is important to note that the system under consideration is a closed system and will not interact with the external electricity market, but the average price was used to account for revenues from sales of exportable electricity. Comparing the system investment cost for low price level, a significant difference can be observed (102–115 M€) between Ref. and alternative systems as expected due to the incorporation of new heating systems. Nevertheless, there is a 100% reduction in electricity import cost and increased electricity revenue in the case of alternative systems, which ultimately balances the annual cost. The 'negative' values are electricity exchange revenues. Generally, as opposed to scenario-1 (47–66 M€) it is fair to say that the total annual cost variation between the Ref. and scenario-2 systems is marginal (11–18 M€) for low and medium price

Table 5
Decision criteria value ranges and assigned weight. 'Best' and 'Worst' refers the most and least attractive values respectively.

Optimization criteria	Criteria values		Assigned weight
	Best	Worst	%
PEC (TW h)	10	20	25
RES share (%)	100	60	25
Net-export (TW h)	7	0	20
Socio-economic costs (M€)	0	700	20
Carbon dioxide emission (Mt)	0	2	10

Table 6
The overall score for the reference and alternative systems. 'Value', 'Norm' and 'Weight' represents the actual value, normalized criterion partial value [0–100] and weighted normalized criterion value, respectively.

	Reference			Scenario-1			Scenario-2		
	Value	Norm	Weight	Value	Norm	Weight	Value	Norm	Weight
PEC	14.56	54.40	13.6	13.65	63.5	15.88	12.23	77.7	19.43
RES share	65.7	14.25	3.56	74.5	36.25	9.06	71.8	29.5	7.38
Net export	2.72	38.86	7.77	6.19	88.43	17.69	5.71	81.57	16.31
Socio-eco.cost	616	12.00	2.4	663	5.29	1.06	598	14.57	2.91
CO_2 emission	1.57	21.5	2.15	1.38	31.0	3.1	1.38	31.0	3.1
Overall score			29.48			46.78			49.12

levels. This is because of the high electricity consumption and out payment of imported electricity in the Ref. system and high fuel consumption in scenario-1, and will therefore also be greatly affected by future price. In essence, a system with high variable costs will always be vulnerable to future cost components and result in long break-even years[9] as compared to similar systems with fewer variable cost components, provided that the difference in investment cost is insignificant. As it stands, the reference system seems to be the cheapest option at low price levels (631 M€) compared to alternative systems, but scenario-2 is still competitive at all levels (642 M€) and is found to be the cheapest solution at medium and high price levels (598 and 507 M€, respectively). This is due to intensive deployment of heat pumps in district heating, which results in reduced and balanced total fuel consumption.

6.2. Scenario rating

As illustrated in the scenario comparison, increased RES could be achieved either by integrating more renewables (wind, bioenergy and solar thermal) in the reference system or by reducing PEC. Reducing PEC increases net exportable electricity whereas using flexible technologies like heat pumps in district heating will open up opportunities to limit biomass consumption and utilize wind generated electricity. Both alternative scenarios show improved standing compared to the reference system in terms of improved electricity imbalance, PEC and RES share. But considering the Norwegian energy policy obligation for increased biomass use (14 TW h by 2020) [2], PEC reduction, 13 new TW h electric energy production and 67.5% renewables share target in the energy mix by 2020 (mainly through wind power) [9,45], the alternative systems are self-conflicting and one is achieved at the cost expense of the other as previously shown in Fig. 4. This implies that the scenarios require further multiple criteria decisions.

The term multiple criteria decision analysis (MCDA) is a method used to combine multiple decision criteria into a given system based on their preferences, and rates each system on the overall weighted effect [46]. MCDA has been used extensively in energy system comparisons based on multiple criteria [47,48]. Although there are hundreds of MCDA methods available today, as described in Ref. [46], they are generally classified into three kinds: value measurement models, goal, aspiration and reference level models, and outranking models. The most widely used approach in value measurement models is an additive value function, multi-attribute value theory (MAVT). In Ref. [47], for example, it was used for western Denmark energy system optimization using large-scale heat pump deployment in the 2020 alternative system. The MAVT approach was therefore used in this study to rate the alternative systems. In this approach, after a series of decision criteria have been selected, potential values will be assigned and normalized with some appropriate scale, e.g. 0–100. Each criterion will then be assigned for weight, a partial value that represents the criteria in the overall score (based on their priority and importance). Finally, the overall score is calculated and compared as the sum of the product of criteria weight and normalized criteria values.

The mathematical formulation is given as follows [46]:

$$V(a) = \sum_{j=1}^{n} w_j[(v_j(a)]$$

where

$v_j(best_j) = 100, v_j(worst_j) = 0, V(best\,overall) = 100, V(worst\,overall) = 0, \forall j$
$v_j = (value_j - worst)/(best - worst)$, is normalization $\forall j$.
w_j, is scaling constant or relative weight of criterion j, $\sum_{j=1}^{n} w_j = 1$, and $w_j > 0, j = 1 \ldots, n$.
$v_j(a)$, is partial value (score) of option a in terms of criterion j.
$V(a)$, is overall value (score) of option a.

Just like its simplicity, the accuracy of MAVT analysis lies with the choice of preference and criterion weight assignment of the most important impact parameters. In the case of the Norwegian energy policy obligation, there is no clear guideline or preference order for achieving PEC, RES or emissions reduction, nor any international standard, as it merely depends on the government's political commitment. Aggregated goal and targets rather reflect the huge interest in achieving low PEC and high RES. These criteria were therefore assigned an equal share, as shown in Table 5.

The result of the MAVT analysis is shown in Table 6. Based on the result, scenario-2 has the highest overall score, indicating that this energy system meets the Norwegian energy policy obligation better than scenario-1 and the reference system. But, as the MAVT overall score indicated, the difference between alternative scenarios is not very significant as compared to the reference system, implying that from a techno-economic operational perspective both systems can contribute to increased flexibility.

7. Conclusions

In this paper, Inland's reference energy system was modeled and validated using the EnergyPLAN tool, aiming to simulate two alternative systems that are perceived to create a flexible energy system for Inland. The result showed that by integrated use of solar, bioenergy and wind energy in the current electricity intensive energy system, substantial reductions in imported electricity and low PEC and high RES could be achieved. In addition, the electricity cut-back and saving, further increase the amount of exportable electricity to ensure national power supply security. On the other hand, little consumption, an established energy policy and the availability of biomass for energy use in the region are key motivators for deployment of bio-heat plants in district heating. With the result, there would be a reduced demand in distributed

[9] Break-even year is the year within systems life time where the life cycle costs of two energy systems are equal. The lesser break-even is the more cost saving over system life time and vice versa.

wood and oil that have been used for space heating in households and cause SO_x and NO_x emissions due to their incomplete combustion in old stoves.

The share of renewables in the primary energy supply for the reference year was 65.7% due to the relatively high oil demand in the transport sector. The transport sector alone accounts for more than 70% of the total emissions. In a move towards a 100% renewable energy system for Inland Norway, in addition to households and industries, the transport sector needs to transform to second-generation biofuels, electric vehicles and/or hydrogen fuelled cars.

Increased exports of excess electricity as a result of energy conservation measures and integration of more renewables in the system would increase a positive balance of payments, create new jobs and enhance societal cost savings. As this study is limited to techno- and socio-economic feasibility, the extent of business economic advantages therefore needs to be studied so as to determine its full techno-economic viability.

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Paper III

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Comparing the value of bioenergy in the heating and transport sectors of an electricity-intensive energy system in Norway

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HIGHLIGHTS

- Bio-heating is less competitive over heat pump for low quality heat production.
- Renewable energy production meets policy objectives better than system efficiency.
- Bioenergy is more valuable in the transport sector than the heating sector.

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ABSTRACT

The objective of this paper is to identify the most valuable sector for the use of bioenergy in a flexible energy system in order to meet the energy policy objectives of Inland Norway. A reference system was used to construct alternative systems in the heating and transport sectors. The alternative system in the heating sector is based on heat pumps and bio-heat boilers while the alternative systems in the transport sector are based on three different pathways: bio-dimethyl ether, hydrogen fuel cell vehicles and battery electric vehicles. The alternative systems were compared with the reference system after a business-economic optimisation had been made using an energy system analysis tool. The results show that the excess electricity availability due to increased energy efficiency measures hampers the competitiveness and penetration of bio-heating over heat pumps in the heating sector. Indeed, the synergy effect of using bio-dimethyl ether in the transport sector for an increased share of renewable energy sources is much higher than that of the hydrogen fuel cell vehicle and battery electric vehicle pathways. The study also revealed that increasing renewable energy production would increase the renewable energy share more than what would be achieved by an increase in energy efficiency.

1. Introduction

For one or more reasons, the transition from a fossil fuel-based to a renewable energy-based energy system has been a goal for both oil-producing and oil 'sink' countries. Nevertheless, despite its multiple benefits, the shift has its own impact and limitations; new intensive infrastructure requirements and their fluctuating nature (demand and supply mismatch) is just one example. With some exceptions like bioenergy and hydropower, most fluctuate where either expensive storage or a load-following reserve capacity requirement for system integration is inevitable (Østergaard, 2009, 2012) and in effect this slows down the entire motivation for and palatability of a green energy system.

In contrast, hydropower-based energy systems smooth out the transition both technically and economically. Norway is a frontline runner with more than 95% of its electricity originating from hydropower, which buffers not only the local market but also that of the Nordic region through the Nordpool electricity market (Norwegian Water Resource and Energy Directorate, 2013). However, intensive hydropower development in the 1990s impeded the use and synergy effect of other potential renewable resources in Norway, e.g. wind and biomass. The share of bioenergy of total energy consumption is 6% (17 TW h), coming mainly in the form of firewood while the estimated potential is 39 TW h – three times today's use (Trømborg, 2011). Wind-power contributes only 1% of the total power generation as of 2011. Energy service infrastructures are heavily based on electricity as a fuel source. In particular the use of bioenergy in the heating sector has been overshadowed by the hydroelectric 'born' direct electric heating, due to cheap electricity in past decades. As of 2009, 94.8% of households

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had direct electric heaters and 55% of them used them as their main heating source, while 18.5% had heat pumps and 14.8% used it as their main heating source (Statistics Norway, 2011). This shows that the heating sector is dominated by direct electric heating, where high quality energy is destroyed (exergy). Electric heaters are easy to install, compact, and require low investment and little maintenance. Nevertheless, their efficiency is low and they constitute barriers to a flexible energy system (Hagos et al., 2014; Danielski et al., 2012). To this end, deployment of waterborne heating systems would be crucial to weakening the strong electricity to heat bond and would open up an opportunity to integrate new renewable energy sources (RES) into the existing system, in order to achieve the Norwegian energy policy objectives (increased RES share – 67.5%, 14 TW h more bioenergy use and 30% emission reduction compared to the 1990 level by 2020).

In a normal year, Norway is a net electric importer where marginal condensing power plants are used to supply the balancing power. For example, between 2006 and 2012, on average, annual hydropower production shows a 17 TW h imbalance in wet and dry years as compared to production in a normal year (Statistics Norway, 2014a). Over and above this, in case of serious falls in precipitation the transmission capacity may not be sufficient to cover the demand. Sandsmark (2009) concluded that upgrading transmission capacity is more realistic than upgrading existing power plant capacity to cover a supply deficit. Thyholt and Hestnes (2008) showed that buildings connected to district heating in Norway could contribute a considerable peak load shaving and reduction in CO_2 emission than an electrically heated building. Furthermore, Rosenberg et al. (2013) suggested that increasing bioenergy penetration and implementing energy efficiency measures in Norway are the most profitable solutions to cover increased demand. All prior studies strengthen the multi-benefits of waterborne heating system deployment in Norway, ensuring evenly distributed electricity prices between interconnected regions, less intensive investment for upgrading transmission lines and substantial emission reductions as it is a key measure towards peak load shaving. However, most of the studies do not point out the limits and values of new RES from the entire energy system perspectives, i.e. the electricity, heat and transport sectors.

On the other hand, a potential space to increase the use of bioenergy in Norway is the transport sector. The transport sector and offshore oil industries contribute to 23% and 29% of total emissions in Norway, respectively (Møller-Holst, 2009). This is a major challenge for Norway to meet its international obligations regarding emission reduction, i.e. 15–17 Mt CO_2 by 2020 (Norwegian Ministry of the Enviroment, 2009). Several studies have investigated the impact of fossil fuel-based energy system emissions on the environment, both nationally and globally. Zhang et al. (2012, 2013) improved the empirical models used to evaluate particulate emissions, Ma et al. (2011) correlated energy consumption and carbon emission in a regional case study, and Zhang et al. (2014) identified the key factors that affect the climate effects of natural gas versus coal electricity production. However, the state-of-the-art technologies intended to abate vehicle emissions will replace or displace conventional fleets with biofuel cars, electric vehicles (EVs) and hydrogen fuel cell vehicles (HFCVs). As such, electric vehicles are ideal solutions if the electricity supply is from RES. However, their limited driving range (150 km on average) makes them most suitable for conventional light vehicle replacement and fuelling heavy trucks and lorries with biofuels is inevitable. Moreover, to the best of our knowledge, the contribution of EVs and HFCVs for increased RES share and its synergy effect with other RES in an electricity-intensive energy system is not clearly known, and needs to be studied and compared with that of biofuels.

The overall understanding is therefore that to rely 100% on a single renewable resource for electricity and heat generation could not guarantee sustainability, but rather it would impede the penetration and synergy effect of other potential renewable resources in a flexible energy system. Hence, this paper analyses and compares the limits, value and benefits of bioenergy integration in the heating and transport sectors of a flexible energy system as a complement to the existing hydro-dominated energy system. Of the 19 counties in Norway, Hedmark and Oppland constitute Inland Norway characterised by some of the highest energy-consuming households in the country, with large floor areas and a high share of detached households (73%). Electricity is the main commodity in the heating sector. The details of Inland Norway energy use by sector is shown in Table 1. This paper therefore considers the Inland[1] energy system to demonstrate this conceptual reasoning.

Table 1
Inland energy use by sector in the reference year (2009) (TW h) (Statistics Norway, 2013).

Fuel	Household	Service	Industry	Transport	Total
Biomass	1.04	0.23	0.45		1.72
Fossil fuel	0.18	0.17	0.34	5.06[a]	5.75
Electricity-heating	1.93	0.95			2.88
Electricity-appliances	1.04	1.16	1.47		3.67

[a] The annual total road traffic volume covered by the transport demand is approximately 4000 million kilometer: passenger vehicles (3057.4), busses (23.3), vans and small lorries (712.5), and heavy lorries and road tractors (144).

The paper is organised into five sections. The first section provides background information about the existing energy system and its foreseen challenges. Section 2 briefly discusses the methodology followed, presents the modelling tool used for the analysis, the data sources and assumptions used, and the scenario-building in alternative systems for the heating and transport sectors. Section 3 discusses the details of the results and findings. Section 4 summarises the results and draws conclusion and its policy implication, followed by suggestions for future work in Section 5.

2. Methods

A reference system (Ref-sys) based on the year 2009 was created and validated in a preceding paper (Hagos et al., 2014) where two alternative systems in the heating sector were built and analysed as a closed system, without external electricity market interaction. That Ref-sys has been used here to build the alternative systems in the heating sector (Alt-heat) and the transport sector (Alt-trans) as shown in Fig. 1, which illustrates the theoretical framework of the study. The reasoning behind this is that such cascaded formulations would help to better understand the incremental contribution of bioenergy in each sector and form a strong base to compare all the systems, i.e. Ref-sys, Alt-heat and Alt-trans. The Alt-heat system focused on the use of heat pumps and bio-heat boilers in individual and district heating (DH) plants as a replacement for direct electric heaters and air source heat pumps in the Ref-sys. Whereas the Alt-trans system is based on three different pathways: battery electric vehicles (BEVs), hydrogen fuel cell vehicles (HFCVs) and biofuel cars (using Bio-DME (dimethyl ether)). Furthermore, each pathway in the Alt-trans system was compared based on an assumed conventional fleet displacement equivalent to an annual road traffic volume of 1 billion km. The reasoning behind this is that BEVs and HFCVs are

[1] In this paper, wherever Inland is stated, the term refers to the Inland Norway of Oppland and Hedmark counties.

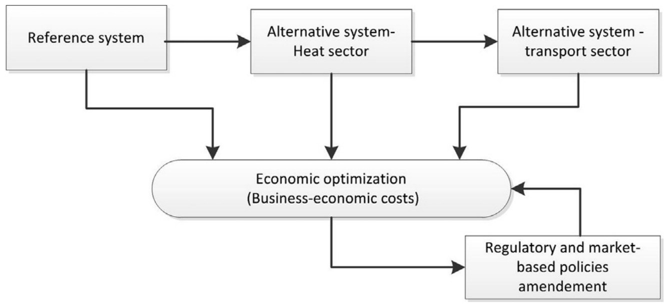

Fig. 1. Theoretical framework of the study.

electricity-powered systems and competitive and fast developing technologies especially in a system dominated by high RES. Comparing these technologies with biofuels would therefore help us to determine the limits, barriers and benefit frontier of bioenergy in Inland Norway and Norway at large. Details of the Alt-heat and Alt-trans systems can be found in Section 3.

As shown in the theoretical framework of the study (Fig. 1), a business-economic optimisation based on business-economic costs (including taxes) was made where the systems were analysed as open systems (direct interaction with the external electricity market) so as to minimise the annual cost of energy supply. To account for the import–export bottleneck, a 2500 MW transmission capacity is assumed and modelled in the system. The role of regulatory and market-based policy instruments in achieving the national energy policy objectives has been discussed to make the most of the business-economic optimisation.

2.1. The EnergyPLAN tool

Energy system modelling and simulation is of a highly fluctuating nature and needs to be simulated within the smallest time step possible to ensure accurate system dynamics integration. The energy system analysis tool EnergyPLAN was chosen for this study for the following reasons: EnergyPLAN is well suited to and capable of integrating the electricity, heat and transport sectors of a given energy system with an hourly time step function over a year. EnergyPLAN is suitable for analysing the value of biomass in an energy system through different pathways: thermochemical (combined heat and power (CHP), bio-heat and gasification) and biochemical (biogas, biopetrol and biodiesel) conversion processes. The tool has been used extensively in the design of a 100% renewable energy system in Denmark and other countries (Lund and Mathiesen, 2009; Connolly et al., 2011; C̀osic̀ et al., 2012), and in highly respected peer-reviewed publications dealing with energy system analysis, of which optimal biomass resource assortment in the electricity and heating sectors (Kwon and Østergaard, 2013), wind power integration using flexible technologies (Østergaard, 2013) and the role of district heating in future renewable energy systems (Lund et al., 2010) are some that can be mentioned. Detailed documentation and free downloads are available at www.energyplan.eu. EnergyPLAN is a deterministic input–output model based on installed capacities and hourly distribution. The main input parameters are aggregate demand, installed capacities, hourly production and demand distribution, efficiencies and optimisation regulations. The outputs are primary energy supply (PES), share of renewable energy sources (RES) in PES, import/export electricity, critical excess electricity production (CEEP) and annual costs. EnergyPLAN has a regulation intended to optimise the system either from a techno-operational or economic-operational perspective. The technical optimisation identifies the most efficient energy supply pathway while the economic optimisation identifies the lowest cost energy supply pathway. For technical optimisation, the tool is inherently set to prioritise use-it or lose-it resources like wind, solar and run-of-river hydropower, then CHP and condensing-mode power production. Business-economic optimisation is based on the external electricity market definition and marginal production costs of the simulated energy system. The system exports electricity when the market prices are higher than the marginal production costs and vice versa.

EnergyPLAN is suitable for analysis of relocation technologies like electrolysers and heat pumps in a flexible energy system. Electrolysers produce hydrogen during excess electricity production to serve as a buffer and heat pumps coupled with thermal storage are used to balance the electricity and heat demand. In addition to the aforementioned benefits in the design of a robust and dynamic renewable-based energy system, the EnergyPLAN tool is also a useful data source.

2.2. Data sources and assumptions

The DH system has been proposed for multi-dwelling buildings assumed to be in the inner cities of urban settlements. The cost benefit of DH over individual heating is usually known to drift with the high DH transmission and distribution costs. The transmission cost represents the cost between heated regions and the distribution cost represents the cost within heated regions. A new method of DH distribution cost estimation in new and expansion areas has been suggested and used to estimate the same in Denmark and a further 83 European cites in Belgium, Germany, France and the Netherlands (Nielsen and Möller, 2013; Persson and Werner, 2011). However, due to data limitations, we prefer to use the weighted average specific costs of a newly approved DH project in Inland. The transmission and distribution networks' capital cost and the total specific capital cost (including central plant) of six newly approved DH projects in Inland are shown in Fig. 2 (Norwegian Water Resource and Energy Directorate, 2013). The reduced specific costs are an indication of the DH economies of scale. Nevertheless, they show a sudden fluctuation due to the non-continuous scalability of the distribution network as it largely depends on geospatial parameters. From Fig. 2, the weighted average capital cost of the distribution network is estimated to be 173 €/MW h. Since the DH central plants uses a different heating technology, as explained in Section 3, the central plant's costs are taken from a separate source, as shown in Table 2.

In Inland, 60% of the power production originated from run-of-river hydro and 40% is from storage hydropower plants. Between 2006 and 2012, compared to a normal year's production, the wet and dry year production shows a 1 TW h surplus and deficit, respectively, and nationally this variation was 17 TW h (Statistics Norway, 2014a). Since the reference system is based on a normal year, it was adjusted to 1 TW h production for wet and dry year simulations.

Data sources for investment, O&M costs of power plants, heating technologies, replacement cost of direct electric heaters

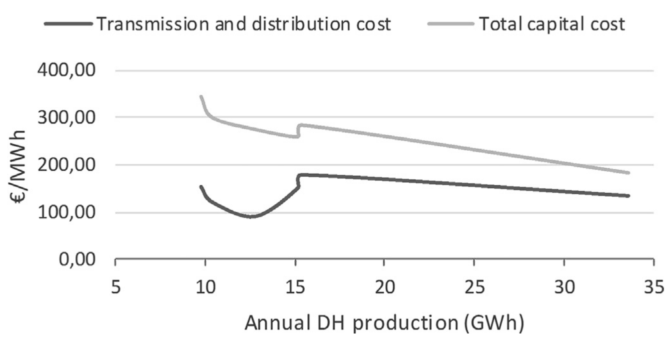

Fig. 2. Specific distribution and capital costs for new district heating systems in Inland.

Table 2
Cost of electric power plants, heating technologies and biofuel plants.

Technology	Investment (M€/MW)	Variable O&M (M €/MW h)	Fixed O&M (% of inv.)	Lifetime (year)	Sources
Power plants					
Hydro power	2.5		1	40	Hofstad (2011)
Onshore wind power	1.6		3	20	Hofstad (2011)
Individual heating plants[a]					
Heat pump-ground source	1.7		1	20	EnergiNet-DK (2012)
Heat pump-air source	0.9		1.5	20	EnergiNet-DK (2012)
Bio-heat boiler	0.68		1	20	EnergiNet-DK (2012)
Electric heating	0.8		1	30	EnergiNet-DK (2012)
Solar thermal[b]	1200		1	30	Hofstad (2011)
District heating plants					
Heat pump	1.7	0.27	0.2	20	Lund et al. (2010); EnergiNet-DK (2012)
Bio-heat boiler	0.68	0.15	3	20	Lund et al. (2010); EnergiNet-DK (2012)
Hydronic heaters[c]	6700		0.5	30	EnergiNet-DK (2012)
Biomass conversion plants					
DME plant	1.6		7	12	Baudin and Nordvall (2008)
Electrolysers	0.93		3	15	Mathiesen et al. (2013)
Storage[d]					
Heat storage	2.45		1	20	Østergaard (2012)
Hydrogen storage	0.5			30	Østergaard (2012)
Vehicle cost[e]					
BEV	25,731		4	13	Hedegaard et al. (2012), Norwegian Electric Vehicle Association (2014)
Conventional car-petrol	10,321		12	13	Mathiesen (2009)
Conventional car-biofuel	13,137		6.5	13	Mathiesen (2009)
HFCV	86,423		1.6	13	Mathiesen (2009)

[a] All heating plants investment cost is given as M€/MW_{th}.
[b] Investment cost is given as M€/TW h.
[c] Investment cost is given as €/units.
[d] Investment cost is given as M€/GW h.
[e] Investment cost is given as €/units.

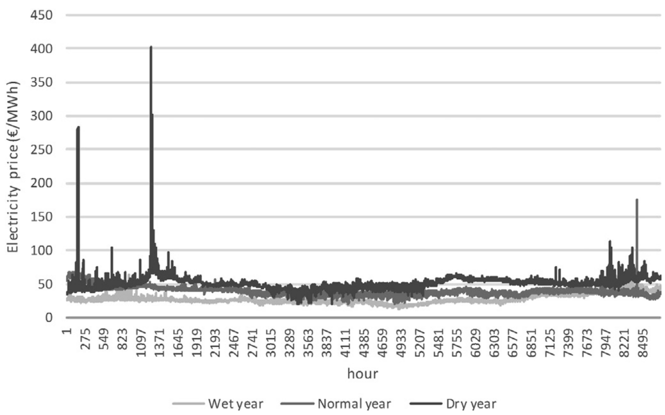

Fig. 3. Average hourly spot market price in Norway for wet, normal and dry year based on the years 2000–2013.

with hydronic heaters, biomass conversion plants, and storage and vehicle costs are shown in Table 2, mostly as of 2015. The historic hourly electricity spot price in Norway between 2000 and 2013 has been used to identify wet, normal and dry year[2] hourly average prices as shown in Fig. 3. The average wet, normal and dry year prices are 29, 40 and 52 €/MW h, respectively. Weighted average electric grid rent and consumption tax for private households and DH plants are taken to be 34 and 20 €/MW h, and 32 and 0.56 €/MW h, respectively (Statistics Norway, 2014b; Norwegian Ministry of Finance, 2014). A range of biomass prices in Norway labelled as low (6 €/GJ), medium (8 €/GJ) and high (10 €/GJ) are also assumed for the sensitivity analysis. Fossil fuel costs (including CO_2 taxes) are assumed to be 14.42, 18.63 and 12 €/GJ for diesel, petrol and heating oil, respectively (Statistics Norway, 2014c). Furthermore, all fuel handling costs are taken from the EnergyPLAN cost database (Connolly, 2012). An interest rate of 3% is assumed for all cases. Currency exchange rates of 0.125 and 0.134 have been used for NOK (Norwegian kroner) and DKK (Danish kroner) to euro, respectively, wherever necessary.

The external electricity market is influenced by import–export levels and EnergyPLAN accounts for this using a price elasticity factor (€/MW h/MW) and a basic price level for price elasticity (€/MW h). Based on prior studies of the Nordic electricity market and Danish local market experience (Lund and Münster, 2006), the price elasticity and basic price level are assumed to be 2 €/TW h/MW and 18 €/MW h, respectively.

2.3. Inland bioenergy potential

As of the reference year 2009, bioenergy use in Inland is limited to 1.72 TW h, mainly of woody biomass used as firewood, as shown in Table 1. The total annual round wood harvest in Inland (3.9 million m^3) constitutes more than 44% of the total annual harvest in Norway (9 million m^3). The annual average sustainable forest-based woody biomass in the region is about 3.29 million m^3 (net forest growth (7.25) minus annual harvest (3.9)), and more than 85% of the productive areas are profitable for harvesting (Statistics Norway, 2014a), meaning that the annual harvest plus 85% of the sustainability could be used to estimate the total harvestable potential to be around 6.7 million m^3. Accordingly, the forest-based bioenergy harvestable and economic potential, roughly estimated to be 5.05 TW h and 2.12 TW h,[3] respectively. This is inconsistent with the

[2] The highest hourly price shown in Fig. 3 is due to a record price of 1400 €/MW h on 22-02-2010.

[3] Rosillo-Calle (2007), suggests that 55% of the harvestable potential would always remain as forest residue, of which 42% is assumed to be the economic potential. A lower heating value (LHV) of 12.34 MJ/kg on wet basis, 30% moisture content and 400 kg/m^3 wood density were assumed for the estimation.

estimation by Lerfald et al. (2009) where Inland's harvestable forest-based bioenergy potential is estimated to be 5 TW h and other herbaceous and putrescible resources to be 1.5 TW h. Furthermore, Trømborg et al. (2007) estimated the economic forest-based bioenergy potential of Inland to be 2.24 TW h. In general, the different sources showed the total bioenergy potential in the region to be 6.5 TW h, and mainly of forest-based biomass resource (77%).

2.4. System optimisation regulations

The regulation used is a business-economic cost optimisation where the system fully interacts with the external electricity market to minimise the total annual cost of energy supply. As such, the system imports electricity if the marginal power production cost of each plant is higher than the market price and vice-versa. EnergyPLAN optimises the business-economic operation of a hydropower plant by generating power during high market price hours while considering the limitations on storage and generator capacity. It is also assumed that the hydropower production is fully driven by the market price. The business-economic optimisation is useful for analysis of the impact of biomass and electricity prices on a district heating system operation built on heat pumps and bio-heat boilers. All operating costs including taxes are included when the marginal production cost of each plant is calculated.

2.5. Scenario building

Details of the reference system can be found in Hagos et al. (2014). This section describes the main elements of the Alt-heat system and the three different pathways in the Alt-trans system.

2.5.1. Alternative system – heating sector

DH is suitable for the deployment of energy-efficient technologies in integrated ways – heat pumps, thermal storage and bio-heat boilers. This is essential for Norway's 67.5% RES share target for final energy consumption, a 15–17 Mt CO_2 reduction and 14 TW h increased use of bioenergy by 2020. Although efforts have been made by introducing promotional policy tools like subsidies and tax exemptions, the share of DH is still hovering at 6% of the total heat market while it is 54% in Finland, 47% in Sweden, 53% in Denmark and 92% in Iceland (IEA, 2013). The main reasons are high distribution costs (due to low population density) and intensive use of direct electric heaters due to the comparably low electricity prices. More than 50% of the inhabitants live in detached houses; the corresponding figure in Inland is 73%. A systematic approach to challenge the high distribution costs is to use individual heat pumps in detached houses (low heat density areas) and DH in inner cities for multi-dwelling buildings (high heat density areas) and the residential and service sectors. Individual heat pumps have a storage tank that can be further integrated with a solar collector. The Alt-heat system has been created with the aim of introducing a high degree of flexibility in the Ref-system as shown below in bullet points where the heating scenarios are added together so as to form the alternative system in the heating sector (Alt-heat).

The DH central plants are based on ground-source heat pumps and bio-heat boilers[4] for two reasons: first, the intention to increase the use of bioenergy in a centralised and efficient way and second, ground-source heat pumps are a well-proven competitive and efficient technology that could supply a large part of the low temperature bulk heat demand. For increased bio-heating penetration and sustainability in the heating sector, bio-heating should therefore be competitive with heat pumps in all respects.

Alt-heat:

- Substitute detached houses' 1.41 TW h direct electric and air-source heat pump heating energy demand with ground-source heat pumps and solar collectors and 0.15 TW h oil heating energy demand with new biomass-fired stoves.
- Substitute 50% of multi-dwelling (terraced houses and flats) houses' 0.63 TW h and the service sector's direct and electric boilers' 0.37 TW h heat energy demand with 1 TW h district heating systems. 0.5 TW h based on bio-heat boilers only and 0.5 TW h based on bio-heat boilers and ground-source heat pumps with heat storage. The capacity of the heat storage is assumed to be 1.5 GW h, which corresponds to average daily consumption.
- Substitute the remaining 50% multi-dwelling houses' 0.63 TW h and the service sector's direct and electric boilers' 0.27 TW h and air-source heat pumps' 0.62 TW h heat energy demand with ground-source heat pumps.
- Substitute industry's 0.34 TW h and the service sector's 0.17 TW h oil-based heat energy demand with individual bio-heat boilers.
- Add 1.27 TW h wind energy.

2.5.2. Alternative system – transport sector

As discussed in Section 2, the Alt-trans system is based on the Alt-heat system and has been used to construct three different pathways, as shown in Fig. 4. In all pathways, the biomass and electricity demand mix is constructed in such a way that the total annual road traffic volume remains constant at 1 billion km. This would enable us to identify the marginal effect of unit increment or decrement of biomass in both sectors and at the same time it constitutes a strong base to compare the different pathways. If the process (production to consumption) efficiency is known, it is possible to compare the different pathways in terms of their impact parameters.

2.5.2.1. Battery electric vehicles (BEV) pathway. Electric vehicles (EVs) offer a lower cost per kilometre than a HFCVs and conventional vehicles (Bulk and Hein, 2009) and contributes to a substantial emission reduction as well (Lund and Kempton, 2008). In a region like Inland where the source of electricity is 100% renewable and in excess, the benefits of the replacement of conventional vehicles with electric vehicles (EVs) are several: reduces emissions, helps to balance excess electricity and reduces the burden on biofuels, which would otherwise be used. Biomass could therefore possibly be assigned a high penetration level in the heating sector. Battery electric vehicles (BEVs) are of interest in this study due to their comparably high penetration level in the current market and their status as a fast-developing technology. The targeted vehicles are passenger cars, due to their driving patterns, charging flexibility, battery size and high market penetration.

The battery-charging scheme is assumed to be dump charging. Charging is assumed to take place during the night, from 4 pm to 4 am, for 12 h. The battery capacity is also assumed to level out consumption for a day. On average, the efficiency of best-selling BEVs in Norway is 7 km/kW h (Norwegian Electric Vehicle Association, 2014). Details of EV modelling using EnergyPLAN is available in Lund and Kempton (2008).

2.5.2.2. Bio-DME (dimethyl ether) pathway. DME has been considered the most promising and viable synthetic fuel as a substitute for diesel in conventional vehicles with a marginal cost for modifications to the fuel injection system. Low emission levels (NO_x and CO_2) and a low boiling point are two of the interesting characteristics

[4] Normally the peak load is covered by natural gas boilers but for the purposes of comparison we assumed the same to be covered by bio-heat boilers in hot-line operation mode.

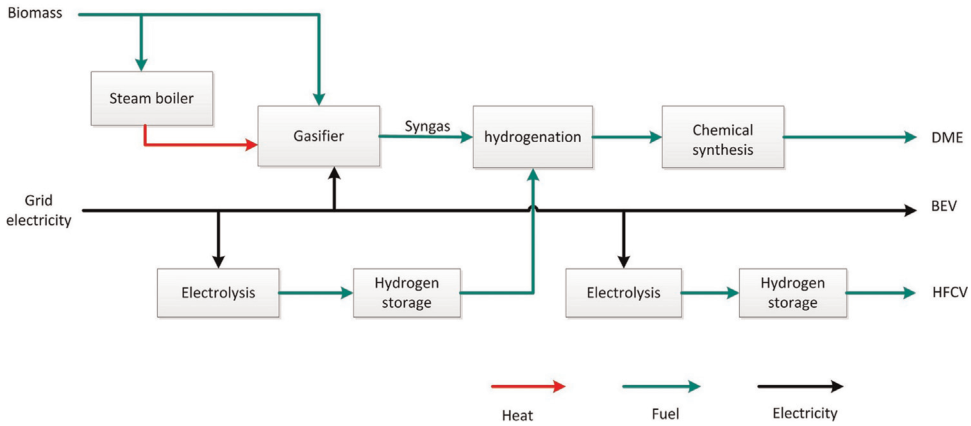

Fig. 4. The Alt-trans system (BEV, HFCV and DME) energy flow diagram.

of DME (Ridjan et al., 2013). In terms of heating value, 1 kg of DME corresponds to 0.8 l of diesel (Baudin and Nordvall, 2008). Although it is not commercialised yet, at best it is on the verge and a few demonstration plants have already been installed (Ridjan et al., 2013). Bio-DME is produced using biomass gasification and a chemical synthesis process. Gasification is intended to increase the heating value of the biomass. The product synthesis gas or syngas is composed mainly of hydrogen and carbon monoxide. Steam is used as a gasification agent to boost the hydrogen content of the syngas and hence, the heating value. The DME pathway is adapted from Ridjan et al. (2013) and Connolly et al. (2014). In contrast to the conventional gasification process, in this specific pathway electrolysers are integrated into the system for further hydrogenation, where the syngas' H_2 content is adjusted for optimal DME synthesis. Biomass consumption could thereby be reduced. As such, the electrolyser helps to limit biomass consumption and serves as a relocation technology for utilisation of surplus electricity. It not only converts the surplus electricity into a liquid fuel but also provides flexibility in the system: heat to DH (if a recuperator or heat recovery unit is installed) and hydrogen to DME plants. Pure oxygen produced in the electrolyser would also be used in the gasification process to avoid the risk of NO_x emissions instead of using ambient air as in a conventional gasification process. Detailed documentation about DME production, properties, technologies, Danish and Swedish experiences, and feasibility studies can be found in Baudin and Nordvall (2008) and Ridjan et al. (2013).

The system impact parameters for the entire processes are biomass, steam and electricity. The gasification steam requirement is 0.64 kg/kg feed or 0.12 TW h/TW h biomass feed (Ciferno and Marano, 2002). Electricity consumption is assumed to be 0.01 TW h/TW h biomass feed (Ridjan et al., 2013). The optimal hydrogen to syngas ratio for the hydrogenation process is taken to be 0.5, which is based on the experimental study in Kaoru and Akane (2010). The steam will be supplied from a separate steam boiler. The cold gas efficiency of the gasifier is assumed to be 90%. Chemical synthesis (syngas to DME) efficiency, including losses, is taken to be 80% (Ridjan et al., 2013).

2.5.2.3. Hydrogen fuel cell vehicles (HFCV) pathway. Hydrogen could be produced from different sources depending on the availability of resources. In a system with a high share of renewables and excess electricity production, electrolysers are not only used to produce hydrogen but also serve as a buffer, as mentioned before. In this pathway, the HFCVs are assumed to be fuelled by on-site filling stations where grid electricity is used for well-to-tank hydrogen production. This avoids new infrastructure being required for hydrogen transportation and storage, especially outside metropolitan areas. The electrolysis efficiency, including all losses, is assumed to be 76% (Mathiesen et al., 2013; Kaveh et al., 2012). In case of on-site hydrogen production, there are less likely to be heat 'sinks' close to the station and recovered heat is therefore not considered. The hydrogen storage capacity, including the car, is sized equivalent to a weekly levelised rate of consumption. The electrolyser operation time is set to 50%, which is based on experience from prior studies (Lund, 2010; Liu et al., 2013; Mathiesen et al., 2013). Hyundai and Mercedes HFCVs have been demonstrated in Norway since 2011 (Fuel Cell Today, 2013). On average, their respective performance is known to be 0.95 kg H_2/100 km or 3.2 km/kW h (Töpler, 2013).

Table 3
Summary of the Alt-trans pathway – energy use, type and efficiency.

Parameters	Ref-sys	BEV	HFCV	DME
Road traffic volume (km/year)	1 billion	1 billion	1 billion	1 billion
Vehicle use (km/year)	26,912	26,912	26,912	26,912
Number of vehicles	37,158	37,158	37,158	37,158
Efficiency (km/kW h)	0.79	7	3.2	0.79
Fuel type	Petroleum	Electricity	Hydrogen	DME
Fuel consumption (TW h)	1.25	0.14	0.31	1.25

Details of the required input parameters for the replacement of 1 billion km annual road traffic volume in each pathways are shown in Table 3.

3. Results and discussion

There is no absolute single criterion for an optimal energy system design but rather it depends on the objective and nature of the energy system in question. However, generally in any energy system, PEC, RES share, emission levels, and annual energy supply costs are used as measuring criteria (Østergaard, 2009). The results and their implications in this section are explained in terms of these parameters.

3.1. Primary energy consumption (PEC)

The EnergyPLAN system analysis tool provides hourly values of production and consumption in the optimised system. PEC is the net domestic energy consumption calculated as the total PES corrected for import(+)/export(−). The source of import electricity is assumed to be marginal condensing power plants in the EU energy market as this is usually the case during dry years and peak demand periods in winter.

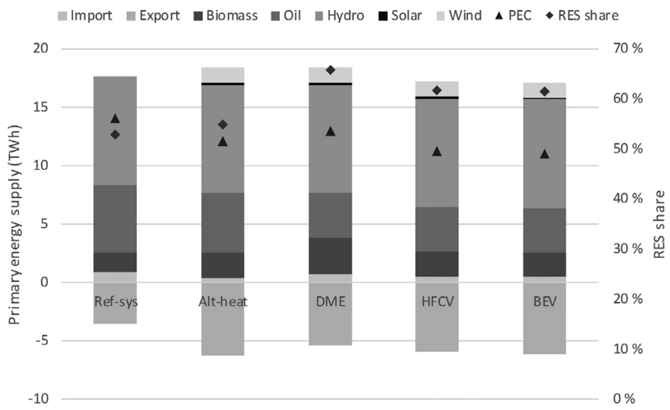

Fig. 5. Primary energy supply of the reference and alternative systems in a normal year.

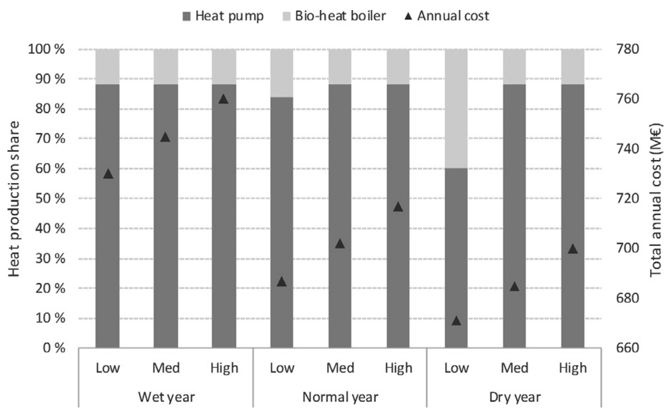

Fig. 6. Total annual cost and DH central plant (0.5 TW h) heat production share of the Alt-heat system for various electricity and biomass price levels without a fixed boiler share.

As Fig. 5 shows, the benefits of PEC reduction due to the energy efficiency measures[5] in the Ref-system were reflected more by the Alt-heat system, and begin to level off in the BEV and HFCV pathways. The incremental benefits of DME, BEV and HFCV deployment in the transport sector were measured in reference to the Alt-heat system. By shifting from the Ref-system to the Alt-heat system, a 1.9 TW h PEC reduction might be plausible, of which 1.82 TW h is green electricity saving, which is more than the remaining 1.65 TW h small-scale economic hydropower potential in Inland (Jensen, 2004); and consequently the incremental PEC reduction in the HFCV and BEV pathways were 0.9 and 1.13 TW h, respectively. Nevertheless, the DME pathway shows an increased PEC of 0.88 TW h. This is because the DME is used in a conventional internal combustion (IC) engine, which is quite inefficient compared to that of a BEV or HFCV. Ultimately this degrades the overall cycle efficiency of the DME pathway.

3.2. Renewable energy source (RES) share

The RES share is estimated based on the International Energy Agency's (IEA) methodology. The RES share is estimated as the total renewable energy consumption (renewable energy production corrected for import–export) divided by PEC. RES share in the total PEC can be increased in two ways: either by decreasing the total PEC or by increasing renewable energy consumption. The Norwegian energy policy has set a target to increase the RES share in total PEC from 60% (which is what it was in 2005) to 67.5% by 2020, which is the main reason for the Norway–Sweden common tradable green certificate (TGC) market launched in January 2012, aimed at 26.4 TW h new electricity production by 2035. Following the large-scale hydropower development phase-out era that began in 2001, energy efficiency measures, and wind and bioenergy developments are considered to be promising avenues for achieving the 2020 target.

The fact that using biofuel (DME) in the transport sector contributes to an increased RES share much better than direct displacement of fossil fuels from the conventional fleet through HFCVs and BEVs is illustrated in Fig. 5. The RES share increases to 66% in the case of DME while it is 62% in the HFCV and BEV pathways. This is because, as opposed to the DME scenario, a large portion of the renewable energy production is exported rather than used inside the system boundary of the HFCV and BEV pathways. The DME pathway thus better illustrates the synergy effects between the electricity and transport sectors, although it is achieved at the expense of a marginal increase in PEC.

[5] Energy efficiency refers to the replacement of direct electric heaters with water-borne heating system (bio-heat boilers and heat pumps), and the conventional fleets with a green fleet (biofuel, BEV and HFCV).

In the Alt-heat system, the excess green electricity was used by the heat pump to limit biomass consumption (on average 2.13 TW h) and was slightly higher than the Ref-system (where it was 1.72 TW h), as the system optimisation identifies the least-cost energy supply pathway. Heat pump dispatch increases when the marginal production cost of the bio-heat boiler is higher than that of the heat pump and vice versa. However, the system considers the effect of increases in electricity consumption on the electricity market price as well. As shown in Fig. 6, in all cases the share of heat pump dispatch increases by as much as 88% except in the case of dry years and low biomass prices, which tend to decrease heat pump dispatch. This is due to the low electricity consumption tax on DH plants and low electricity market price as a result of the excess electricity availability. In turn, the increased energy efficiency contributes to a marginal increase in RES share. The average of wet, normal and dry year is 55% while it was 53% in the Ref-system, whereas the incremental increase in the Alt-trans system is much higher than that of the Alt-heat system: 66% for DME and 62% for the HFCV and BEV pathways. This illustrates the fact that the contribution of increased renewable energy use inside the system boundary for increased RES share is greater than that of increased energy efficiency. When comparing the contribution of bioenergy in the Alt-heat and Alt-trans systems, increasing bioenergy penetration in the transport sector is more valuable to achieving Norwegian energy policy obligations, i.e. increased use of bioenergy and high RES share. In an earlier study, Trømborg et al. (2011) also showed that the 14 TW h bioenergy target is less likely to be achieved by the heating sector alone due to other competitive heating technologies and low electricity prices.

Although electricity production is in excess, as shown in Fig. 5, the system tends to import electricity during peak demand periods in the winter season. This is because, the hydropower production spots high electricity price hours rather than balancing the water supply and storage capacity for peak load supply, resulting in poor storage management. Since the source of all imports is considered to be condensing power plants, the effect on RES share is reflected in a 1% lower RES share in dry years and a 1% increase in wet years compared to the normal year in all scenarios (this is a small variation and is not visible in Fig. 5). This was also confirmed by prior studies; e.g., in 2008 (wet year), 2009 (normal year) and 2010 (dry year), the RES share in Norway was 62%, 65% and 61%, respectively (Bergesen et al., 2012).

Within the transport sector alone, with a 1 billion km replacement, a 25%, 4.3% and 5.5% RES share in the transport sector could be achieved using the DME, HFCV and BEV pathways, respectively. As such, when the 10% RES share target in the EU renewable energy directives (2009/28/EC) is calculated, the directive

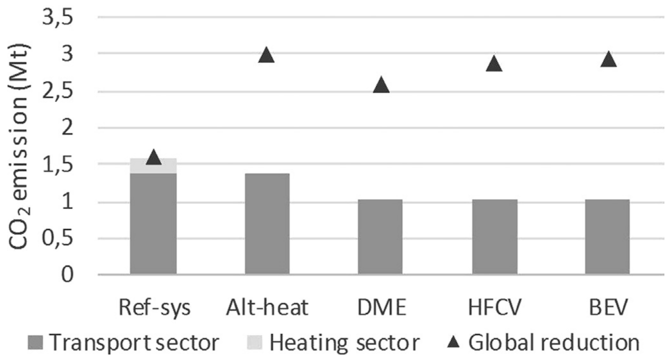

Fig. 7. CO_2 emission levels in the reference and alternative systems. The global emission reduction is due to the exportable green electricity assumed to replace condensing power plants generating electricity (outside the modelled system boundary) with an emission factor of 415 kg/kW h.

counts every unit of TW h second-generation biofuel[6] as 2 TW h, but 2.5 TW h for EVs and HFCVs provided that the source of electricity is renewables (EU, 2009). Taking this into account, a further 40%, 10% and 12.6% increase in RES share using DME, HFCV and BEV, respectively, could be achieved, which is higher than the 10% target for 2020.

3.3. CO_2 emission

Given that power production is 100% renewable, heat production is 93% renewable and that there is little industrial activity in the region, the only potential source and place for emission abatement is the transport sector. More than 70% of CO_2 emissions in the reference system originates from road transport. In Inland, an annual volume of 1 billion km is covered by 18% of the conventional passenger cars. As shown in Fig. 7, a 1 billion km replacement would be able to reduce total emissions by 25% (0.35 Mt) and together with the heating sector the total emission reduction could be increased to 34% (0.54 Mt), which is greater than Inland energy agency's 2020 target (22% reduction target as compared to the 2005 level) (The Inland Norway Energy Agency, 2010). The reduction in CO_2 emissions from the conventional fleet is equivalent to 350 g CO_2/km, which is three times more than the emissions from average conventional cars in Norway (130–135 g CO_2/km) (Institute for Energy Technology, 2012). This is due to the relatively cold winters in Inland (low efficiency of IC engines associated with low ambient air temperature), 0.79 km/kW h in the reference system.

In an energy system dominated by condensing power plants, the effect of BEVs in integrating renewables for emission reduction comes more from the power plants than the direct displacement of conventional cars (Lund and Kempton, 2008). This leads to the conclusion that in a system with a high share of RES, the environmental benefits of shifting to a 'green' fleet are at both national and global levels, as exports are not credited for emission reduction inside the system boundary. First, from conventional cars' displacement by the 'green' fleet at national level and second, since the Norwegian grid is an integral part of the EU energy market, the increase in exportable green electricity production in Norway would reduce emissions from the marginal power production plants that would otherwise cover the demand deficit in the Nordic electricity market, as indicated in Fig. 7, by a global reduction (referring all regions outside the modelled system boundary).

3.4. Business-economic costs

3.4.1. Cost-benefit analysis of heat pumps and bio-heat boilers

For the purposes of comparison, the DH system based on bio-heat boilers and heat pumps (0.5 TW h) in the Alt-heat system has been used here. As such, in contrast to the heat pump, the hourly system optimisation limits the bio-heat boiler heat dispatch much less than its rated capacity in all price scenarios, as shown in Fig. 6. This is because the marginal production cost using bio-heat boilers were higher than with the heat pumps due to low electricity consumption tax on DH and excess electricity availability, which also reduces the local market price. The bio-heat boiler therefore has a limited cost-benefit in a system cost optimisation perspective.

In any techno-economic study it is a key step to understand the impact parameters, which could ramp-up or ramp-down the annual cost of the system. Fig. 6 illustrates the annual cost response in the vertical band for electricity and biomass price changes. Comparing the wet year with that of normal and dry years, the impact of electricity price is found to be almost three times as high as that of the biomass price. Consequently, the share of the bio-heat boiler in the DH plant is limited to 12% in all cases except in the case of dry years and low biomass prices, which show a 40% share. Reasonably, 6 €/GJ is a fairly low biomass (wood chips) price in the current market. As such, the low biomass price alone would not increase bio-heat's competitiveness unless it is complemented by a high electricity price. The main impact parameter is found to be the electricity price, which could possibly increase the marginal production cost of the heat pump whereby the bio-heat boiler dispatch increases. However, heat pumps are more applicable and efficient (maintain their COP, coefficient of performance) at low supply temperatures: 62–80 °C (Mathiesen et al., 2011), which is equivalent to a large volume of the DH demand.

To account for the opportunity cost associated with intentional increases in biomass consumption due to several reasons (public and private owners interest, or political goal), the bio-heat boiler share was fixed at 25% and the system is allowed to decide for the remaining 75% heat demand, as shown in Fig. 8. The biomass consumption increases by as much as 2.63 TW h in a dry year. However, comparing the annual costs between Fig. 6 and Fig. 8, the annual cost of the system with fixed share increases of the same order as the biomass price increases, 1–4 M€ in all scenarios, is equivalent to an increased marginal production cost of 2–8 €/MW h. The understanding is that, the increased biomass consumption would be at the expense of higher energy supply cost.

3.4.2. Reference and alternative system costs

The detail business-economic annual costs for a normal year are shown in Fig. 9, and only the total annual costs in wet, normal and dry years for the purposes of comparison are shown in Fig. 10 for all scenarios. Except for transmission and other associated infrastructure costs, all investment costs of power plants, heating technologies and new vehicles (corresponding to 1 billion km) in the reference system are included. The BEV pathway is found to be the lowest cost solution in all cases of wet, normal and dry year. However, in order to create a flexible system, investment in new infrastructures is inevitable. It is clear from Fig. 9 that the cost benefit of energy carrier switching is substantial in that the revenue from excess electricity trade offsets a large part of the cost of investment in alternative technologies. Compared to the reference system, except BEV pathway, all alternative systems show an increased annual cost[7] in wet and normal years – Alt-heat (1–36 M€), DME (45–70 M€) and HFCV (142–175 M€). All systems, except

[6] Biofuels are produced from wastes, residues, non-food cellulosic material, and ligno-cellulosic material.

[7] The system cost or annual cost is the sum of all expenditures minus the revenue from electricity trade.

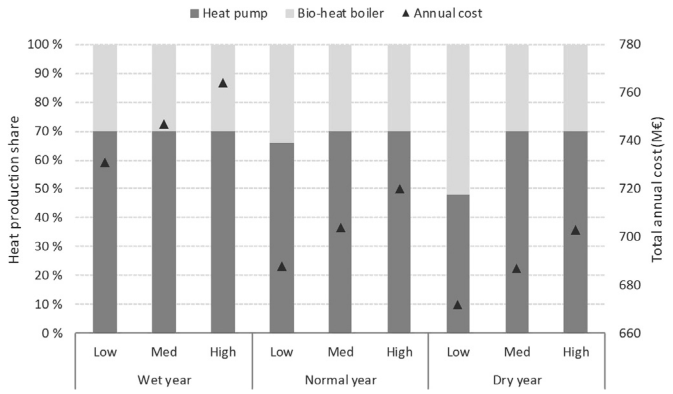

Fig. 8. Total annual cost and DH central plant (0.5 TW h) heat production share of the Alt-heat system for various electricity and biomass price levels with a 25% fixed boiler share.

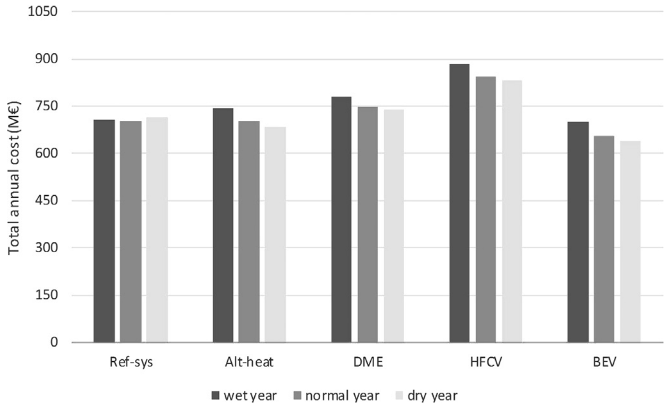

Fig. 10. Total annual costs for wet, normal and dry years in the reference and alternative systems.

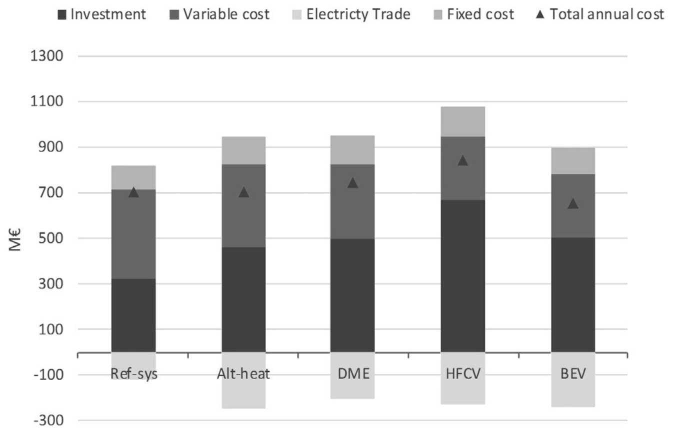

Fig. 9. Detailed business-economic annual costs of the reference and alternative systems in a normal year.

the reference system, show a reduced annual cost in dry years. This is due to the high electricity market price and hence increased revenue. The BEV pathway is the lowest cost energy solution as well as the most efficient in terms of energy supply, while the HFCV pathway is the highest cost scenario. This is due to the high investment cost of HFCVs in today's market, which will most likely decline substantially in the future as technology advances and market penetration increases (Mathiesen, 2009). The reference system is vulnerable to high prices while the alternative systems are vulnerable to low prices, and hence less revenue.

Different studies have shown that in a system with a high share of RES in the electricity sector, BEVs are ideal solutions in the transport sector for both emission reduction and reduced PEC at a lower socio-economic cost (Svensson et al., 2007). Furthermore, deployment of individual heat pumps and DH solutions offers a lower socio-economic cost for electric heating, as studied in the 2020 and 2060 future energy system of Denmark (Lund et al., 2010).

4. Conclusions and policy implications

In this paper, two alternative systems for the heating and transport sectors were constructed and compared with the reference system based on a business-economic optimisation with the aim of comparing the value of bioenergy in the heating and transport sectors. The results show that increased use of bioenergy in the heating sector would be hampered by heat pump competitiveness due to the excess green electricity availability and the low electricity consumption tax on DH. This was noted by the effect of electricity and biomass prices on the annual energy supply cost. Compared to bio-heating, ground-source heat pumps are found to be better alternatives in the heating sector for low quality heat production. However, this does not include putrescible biomass resources, which would otherwise be wasted, and those used in industry and service sectors for high-quality energy production. Rather, as reflected by the Bio-DME pathway on the Alt-transport system, the limited biomass resource could be used to create a strong synergy effect between the electricity and transport sectors.

The effect of bioenergy in the transport sector for increased share of RES is found to be higher than that of the BEV and HFCV pathways. The main reason is that in contrast to other scenarios the Bio-DME pathway uses much of the renewable production inside the system boundary rather than it being exported outside the system boundary. The BEV and HFCV scenarios are energy efficiency measures while the Bio-DME represents increased renewable energy production, which implies that increasing renewable production would increase the RES share more than what would be achieved by an increase in energy efficiency. The implication is that the transport sector would play a key role in achieving both the 14 TW h increase in bioenergy use and the 67.5% RES share target by 2020.

In this paper, we have seen the intent (not the full-scale replacement) of the techno-economic benefits of converting the conventional fleet into a ‘green’ fleet with Bio-DME, BEVs and HFCVs. Biomass-intensive pathways are vulnerable to future prices as they depend on the supply chain and transport costs. The theoretical bioenergy potential in Inland is 6.5 TW h (77% forest-based). The economic and perhaps politically available potential would be much lower. An increase in biomass demand above the available potential will therefore certainly put pressure on the sustainability and biomass price in the region and the optimal penetration level needs to be studied in detail. The optimal penetration could be done by analysing the long-term optimal production mix in the Inland region, considering resource constraints and demand forecasts, in integrated district heat and second generation biofuel production plants and see what the socio-economic optimal mix is if we also consider investment costs for all production units.

The business-economic optimisation also showed that despite the high investment cost to establish the alternative systems, electricity trade revenues offset much of the out-payments, so as to make the alternative systems competitive at all price levels. The BEV pathway stands out as the lowest cost solution compared to the Bio-DME and HFCV pathways. This is due to the relatively high investment cost of a DME plant and a reduction in exportable electricity, and hence lower revenues. Due to technical limitations, however, fuelling heavy trucks and lorries with biofuel is inevitable. The preference to meet policy objectives (RES share, reduced PEC, ensuring power supply security and least-cost energy supply) therefore determines the level of BEV, HFCV and Bio-DME penetration, implying that a further multi-criteria decision analysis is required.

The foreseen challenges of the existing energy system with a business-as-usual scenario have been discussed in the introduction. Investing in new energy service infrastructures is not only a remedy for short-term peak load shaving, but also helps to shape the future energy system of Inland Norway and Norway at large. Regulatory and market-based policies are important tools for transforming the existing electricity-intensive 'rigid' energy system into a flexible energy system. For buildings with less than 500 m^2 floor area, the current building regulation requires 40% of their heating demand to be covered by something other (district heating, heat pump, bio-heating or solar collector heat sources) than direct electric heating and oil heating (Ministry of Local Government and Regional Development, 2010). This figure increases to 60% for buildings larger than 500 m^2. Considering the low electricity price and the high heating demand in the household sector (on average less than 100 m^2 floor area and 26,000 kW h/year) (Hagos et al., 2014), the current building regulations have a very limited impact on reducing the use of direct electric heaters. Building regulation amendments to create a competition between heat sources are therefore critical to a sustainable waterborne heating penetration and increased energy efficiency. The tax on electricity consumption from DH plants is almost zero as compared to individual heating (32 €/MW h), which aims to increase DH penetration, and seemingly the tax would pay heat pumps for increased efficiency, as opposed to the case in Denmark where the tax on large-scale heat pumps is based on heat production (Mathiesen et al., 2011). In the short-term, therefore, distorting the tax on electricity use in individual heating might demotivate the use of direct electric heaters as a main heat source while heat pumps offset the incremental price marginal effects with increased efficiency. In the long-term, however, the regulatory policy is more crucial than the market-based policy as this would create a sustained competition between heat sources. In a nutshell, incentives for low quality heat production shall prioritise ground-source heat pumps over bio-heating excluding putrescibles, which would otherwise be wasted, and those used for high-quality heat production in the service and industry sectors. Rather, promoting second-generation biofuels would be very important for a rational and optimal use of this limited resource.

Electric vehicles (EVs) are heavily subsidised in Norway. The subsidy includes tax exemptions, use of bus and collective lanes, parking fee exemptions, and free battery charging at publicly funded charging stations. As a result, the local market share between 2005 and 2013 increased from 1.4% to 5.5%, and the global market share of EV sales in Norway increased to 7% as of 2012 (Holtsmark and Skonhoft, 2014). However, compared to EVs, first generation biofuel vehicles are almost non-existent. In addition to subsidising the investment cost of the central production plant, similar policy instruments, such as free use of expressways need to be implemented to stimulate the use of biofuels in the conventional fleet.

5. Future work

Since this study is limited to an hourly analysis of a fixed annual demand and bioenergy application for low quality heat production, it would be interesting to analyse the benefits of bioenergy for both high-quality (CHP plants) and low-quality heat production in the future energy system, with a long-term perspective that includes investment and operation cost optimisation.

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Paper IV

The prospects of bioenergy in the future energy system of Inland Norway

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Abstract

The aim of this paper is to study a biorefinery integrated district heating (DH) and individual and central bioheating systems in an electricity intensive energy system to identify the prospects of bioenergy technologies over conventional technologies as the system evolves in a long time horizon (2009 to 2030). Two gasification based biorefinery plants were selected: a Fischer-Tropsch (FT) biodiesel and a dimethyl ether (DME) biorefinery. Given that electricity is the main commodity, a base case and three alternative scenarios with an annual 2.5% electricity and biomass price escalation rate were formulated. The results showed that, for the base case price scenario, a minimum of 6 €/GJ biofuel subsidy is required to initiate investments in a dimethyl ether (DME)-biorefinery. For a higher energy price scenario (biomass and electricity), Fischer-Tropsch (FT)-biodiesel is found to be profitable over DME and requires a minimum of 12 €/GJ biofuel subsidy. For biomass CHP competitiveness in DH, electricity price is found to be the most determining factor over biomass price. In individual and central heating, despite the high electricity tax, pellet boilers were found to be less competitive than heat pumps and electric heaters, primarily due to high pellet price. In conclusion, earmarking biomass in DH for CHP and biorefineries and heat pumps in individual, central heating and DH are found to be an optimal solution.

Key words: TIMES, FT-biodiesel, Dimethyl ether (DME), Biorefinery, District heat, Heat pump

1 Introduction

The Norwegian government has earmarked bioenergy as one of the major contributors to the targeted 67.5% renewables share by 2020, mainly through district heating (DH) which has been promisingly used as a replacement to direct electric heaters in the heating sector and as a biofuel in the transport sector.

Second generation biofuels could be produced by either thermochemical or biochemical processes, and also through a combination of the two process. The key sub-process for the thermochemical process is biomass gasification where biomass is converted to syngas and subsequently converted catalytically into biofuels (FT biodiesel, biogasoline, methanol, DME, or ethanol) using dedicated catalysts, whereas the key sub-process for the biochemical pathway is fermentation (anaerobic digestion) where the lignocellulos biomass is enzymatically treated to break the cellulose into simple sugars that ferment into ethanol. Production of ethanol and biogas from putrescible biomass resources using the fermentation process is a well-developed technology but is still a biomass intensive process. Forest-based (woody) biomass resources, however, are less suitable for the fermentation process due to the hydrolytic stability and structural robustness of lignocellulose, and hence it is an energy intensive process [1].

Biomass gasification has evolved as a promising technology for second generation biofuel production as well as heat and electricity production (as a by-product) [2]. The Biomass Integrated Gasification Combined Cycle (BIGCC) enables a higher power-to-heat ratio than the conventional steam cycle. It is also considered a promising technology to inflate, techno-economically speaking, the value of bioenergy using DH as a low quality heat sink [3–6]. Lignocellulos biomass has been found to be suitable for the gasification process, which in turn is suitable for making use of forest-based resources in a sustainable way, serving as a gateway to skip the food-energy debate as well. Elisabeth et al. [7] studied the effect of pol-

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icy instruments on biomass gasification based synthetic natural gas (SNG) biorefinery in a DH. In conclusion, to be competitive over biomass gasification based CHP and conventional CHP investments, a 24 to 42 €/MWh biofuel subsidy level is required to initiate SNG biorefinery investment. Danica djuric et al. [5,6] also showed in two subsequent studies that Fischer-Tropsch diesel and bio-DME integrated DH plants are profitable only under a considerable biofuel subsidy (greater than 26 €/MWh) due to their lower thermal and electrical efficiency. Frederik Trippe et al. [8] studied the techno-economic performance of biopetrol (biogasoline) using DME synthesis and FT synthesis pathways. They concluded that DME pathway is less costly than the FT pathway although both are found to be a little more costly than the current conventional refineries market price. In similar studies, the amount of heat recovered from BIGCC plants corresponding to the EU 10% biofuel goal is found to be less than that of the EUs total DH heat sink capacity [4,9], which could potentially supply a large part of the DH base load demand. However, all of the above studies were made in sub-optimized systems, i.e. local DH systems, not from an entire energy system optimization perspective.

In a previous study from 2003, the cost-effectiveness of bioenergy for emission reduction in the transport sector was found to be less than that of the heating sector [10], based on the technologies available at that time. This result was mainly due to the high investment cost of the assumed biofuel technologies in the transport sector. Coupling of biofuels investment with a DH system might have a cost advantage, and would share some momentum from the already established DH market. Moreover, if the most important parameter for subsidy (electricity, heat or biofuel) is identified and implemented, the support would create a further self-sustained market growth and thereby large-scale introduction of biofuels could be envisioned in the long run.

Biomass gasification based second generation biofuel production plants are not yet commercialized, but at best are on the verge. The assumption is that the existing bioheat boilers in DH would be phased out by the time commercialization begins and integrated biofuel and DH plants would be of interest, techno-economically, for DH suppliers to invest in as well as for policy makers to reevaluate their policy instruments. The purpose of this study is to analyze a more integrated system having stronger synergy effects between the electricity, heat, and transport sectors whereby the prospects of bioenergy in the future energy system is determined, i.e. bioenergy investments in the energy mix. First, a model which includes both the conventional (combined heat and power (CHP), heat pump, and bioheat boiler) and biorefinery technologies (biomass gasification-based biorefinery) is constructed based on the TIMES model. The calibrated model is then applied to analyze the energy system subjected to resource constraints and various policy frameworks as the system evolves in a long-term frame from 2009 to 2030 for the region Inland Norway.

One of the benefit of a regional system study is to identify the prospects of local resources and an optimal plant locations for geospatial resources like forest-based biomass resources. The paper is organized into 5 sections. The first section provides background information and the objective of the study. Section 2 provides brief information about the current energy system. Section 3 briefly discusses the methodology followed and presents the modeling tool used for the analysis based on structure, purpose and function. Section 4 discusses results and findings, followed by conclusions in section 5.

2 Inland energy system

The energy system of Inland [1] is manly characterized by its 100% hydropower based electricity production and intensive use of direct electric heaters as end use device in most of the households [11]. More than 94% of the households (more than 73% detached households) had direct electric heaters, 55% of which used them as a main heating source. Recently, due to more incentives and promotions, alternative heating sources are coming to be of interest such as DH, individual heat pumps, and bioheating. As of 2009, use of fossil fuel was 5.75 TWh, and the corresponding emission was 1.57 Mt CO_2 (excluding emissions from agricultural activities) [11,12]. The main source of emission is the transport sector, which is responsible for 70% of total emissions, and the remaining 30% comes from heating sector. Fossil fuel is largely used for transport purposes, around 88% (diesel and petrol), and 12% as heavy fuel oil for heating purposes. The Inland energy agency, which is the first of its kind in Norway, has a regional energy strategy to increase energy efficiency, renewable share, and emission reduction, in line with the national energy policy objectives.

Compared to fossil fuel dominated energy systems, the existing Inland energy system can perhaps be regarded as an efficient and least-cost energy system as it is dominated by low-cost end-use devices (i.e. direct electric heaters) although a considerable amount of exergy is destroyed [2] [11–13]. This is due to the comparatively low electricity price in past decades. The common and conventional definition of energy efficiency is that of the first-law of thermodynamic efficiency, which considers only the energy quantity and not the quality (exergy). In an electricity-intensive system, however, the second-law efficiency shows a better picture of energy utilization as

[1] Oppland and hedmark are the two counties located in the east of Norway with a total population of 374,359 and 52,590 km^2 land area that constitute Inland Norway

[2] Exergy is the maximum potential of a system to do work in reference to a dead state or ambient temperature.

electricity is 100% exergy and the second law considers both energy quantity and quality (exergy) [14]. The first (energy) and second law (exergy) efficiencies of, for example, direct electric space heaters are 99% and 6%, hot water heaters 90% and 10%, and heat pumps 380% and 19%, respectively [13]. Therefore, with regard to alternative technology selection, as explained in section 3, we were more focused on the replacement of direct electric heaters with lower exergy destruction technologies.

Table 1
Existing district heating central plant composition by fuel source and purpose [15].

DH production (GWh)	Base load and bulk load		Peak load
	Bioheat boiler(%)	Electric boiler (%)	Natural gas boiler(%)
994	70	15	15

DH in Inland is in its infancy. Most of the plants began production in 2012 or so. As shown in Table 1, bioheat boilers are the main heating units in the central plant and cover a large part of the base load while natural gas and a few electric boilers are used to cover the peak load and serve as backup units.

3 Methodology

As indicated in the introduction, this paper models a regional energy system with the aim of pinpointing if bioenergy technologies are competitive over conventional technologies in an electricity-intensive energy system. This section outlines the model structure, chosen central and end-use technologies, assumptions, and data sources used in constructing the model, modelling tool used, and scenario and sensitivity cases for further analysis.

3.1 Model structure

The modeling and analysis are based on a regional and national real policy case study. The reference system is calibrated based on 2009 data (recent available regional data), and has no DH system but new DH plants have been approved since then. Therefore, a unified DH system based on Table 1 has been calibrated in the model. New DH plants investment is made available starting from 2020. Heat demand technologies are classified as central heating (row houses and multi-dwelling buildings), individual heating (detached houses (73%) [3]) [16], district heating for commercial buildings (service sector), multi-dwelling buildings, and industries. Heat and electricity demand forecasts for the residential and service sectors have been made (shown in section 3.4). Industries' heat demand is assumed to grow annually by 3%. The heating technologies are allocated based on heat demand class and further divided into hot water and space heating. There are eight heat demand classes in the residential sector and five in the service sector. The detail model structure is shown in Fig. 1.

For the DH system, a biomass gasification based combined heat and biofuel (from now onwards in this paper, biofuel refers to a second-generation biofuel) integrated with a conventional district heating system is of particular interest in this study, due to the large supply of forest-based biomass resource in the studied region. Wood-based biomass gasification is a relatively well-developed technology while herbaceous biomass gasification is still at the development stage.

3.2 Individual and central heating technologies

Direct electric heaters dominate in the reference system, followed by wood stoves and air-to-air heat pumps (HPs). More than 70% of the service sector has a central heating system comprising electric boilers, oil boilers, and air-to-water HPs. In addition to the existing technologies, an alternative individual [4] hydronic heating system comprising bioheat boiler, water-to-water HPs, and solar thermal systems for many of the detached households are made available, in the model, for new investment. New individual heating investments include a new hydronic distribution system, and all existing central heating systems are assumed to have a hydronic system. The existing stock of oil-fired boilers is assumed to be phased out after the second milestone year (2020), and additional constraints are also imposed to avoid reinvestment. For this analysis, the heterogeneity of households energy consumption behavior is ignored, but access to technology and demand levels are considered. The intention is mainly to identify bioenergy investment opportunities in light of other alternative technologies. Due to the limitations in storage space requirements, the bioheat boilers in the residential and service sectors are assumed to be fueled by only wood pellets.

3.3 District heating (DH) technologies

The conventional technologies in the central plant composition of the DH system are CHP, water-to-water HP, bioheat boiler, and peak load natural gas and electric boilers (Fig. 2). In addition to this, district heating optimized biorefinery plant might be of interest in the future energy system. The process and energy flow diagrams for such plants are shown in Fig. 3. In this pathway, a gasification based biorefinery plant producing electricity, heat, and biofuel is considered. Such kinds of

[3] The share of dwellings by type is as follows: Detached houses (73%), Row houses (7%), Multi-dwelling buildings (8%), houses with 2 dwellings (8%), and other buildings (4%).

[4] Individual refers to single family direct or without waterborne heating system while central refers to a waterborne heating system like those found in multi-family dwellings and large buildings in the service sector.

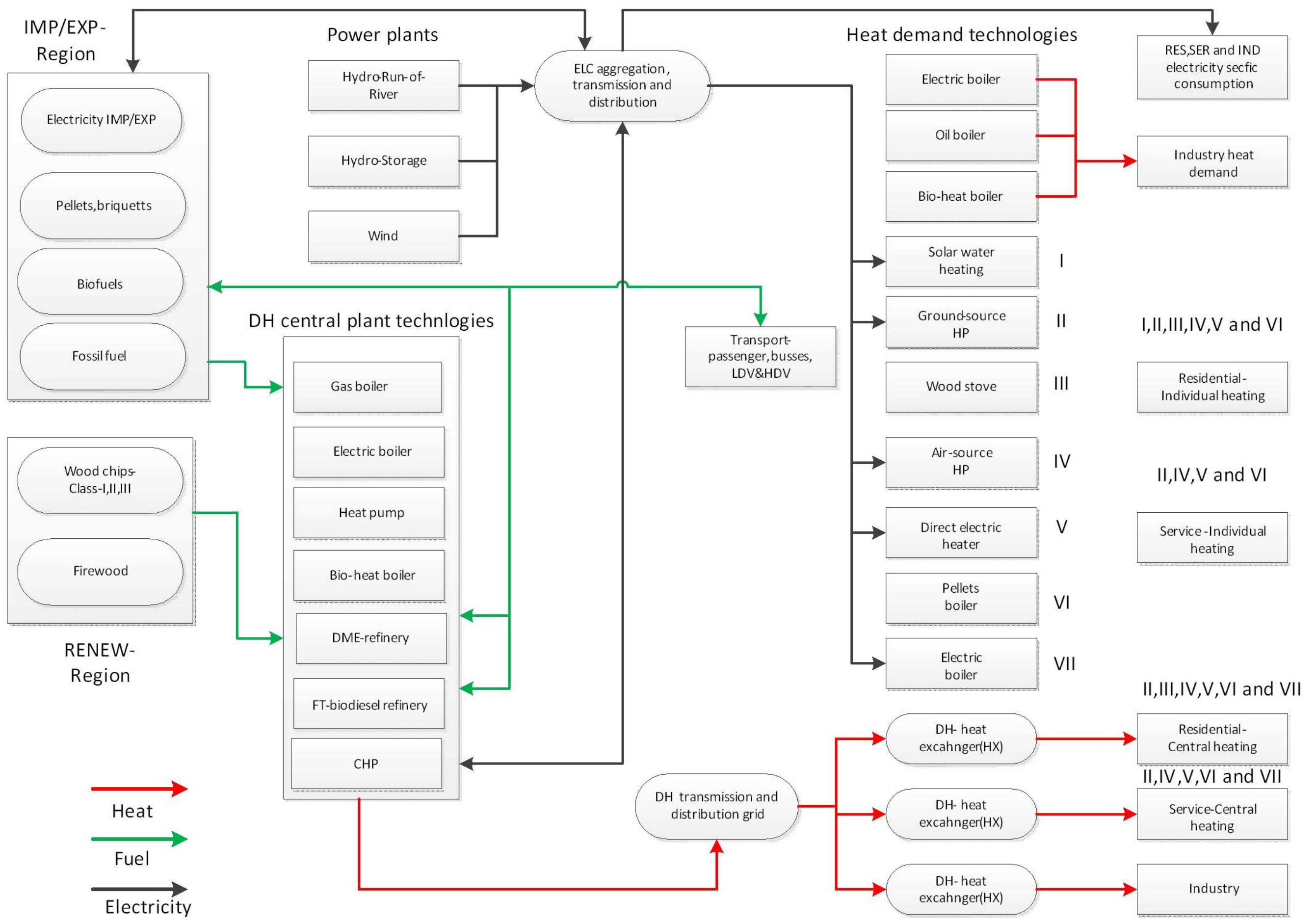

Fig. 1. Model structure and energy flow diagram.

plants usually have an integrated heat and power production (CHP) unit that supplies the plant's electricity and steam demand. The heat recovery steam generator (HRSG) supplies steam to the steam turbine and to the gasifier (steam is used as an oxidizing agent). The hydrogenation process down to HRSG helps to regulate the cooler syngas hydrogen content, which in turn helps to reduce the feed-in biomass consumption although this is at the expense of increased electricity consumption.

A large number of biorefinery technologies are currently in the development phase. In this study, we analyze two of the most promising ones, Fischer-Tropsch (FT) biodiesel [5] and Dimethyl ether (DME). The selection is based on feed-in biomass type (wood chips), process data availability, technology development stage (at least demonstration stage), and the role of the biofuels in the energy system.

[5] In the FT-biodiesel process, biodiesel is the main product while biogasoline, heat, and electricity are by-products.

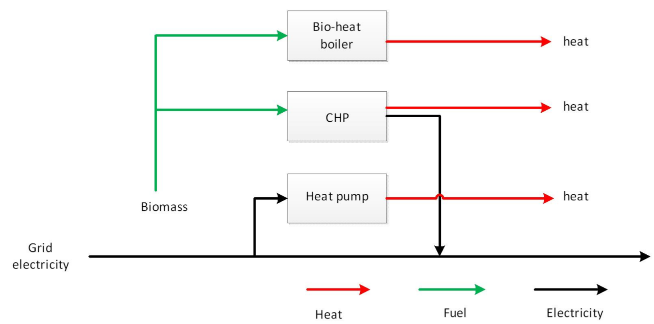

Fig. 2. Conventional CHP based DH system central plant composition.

3.4 *Green transport technologies*

The technologies included are standard vehicles, passenger electric vehicles (EVs), and hydrogen fuel cell vehicles (HFCVs). Biofuels are blended in standard vehicles, excluding fuel flexible vehicles, as standard vehicles would continue to dominate even after the model horizon (2030). Biodiesel blends in the range of 2-20% can be used in most diesel engines with no or minor mod-

Table 2
Load factor and specific energy consumption of vehicles by transport type [17,12].

Fuel source	Passenger vehicles		Buses		Freight transport (LDV and HDV)	
	Load factor (p-km)	Specific energy consumption (MJ/p-km)	Load factor (p-km)	Specific energy consumption (MJ/p-km)	Load factor (p-km)	Specific energy consumption (MJ/p-km)
Diesel	1.5	1.88	36	0.29	12	0.86
Petrol	1.5	2.09	36	-	12	-
Hydrogen Fuel cell	1.5	0.7	36	-	12	0.88
Electric vehicles	1.5	0.32	36	-	12	-

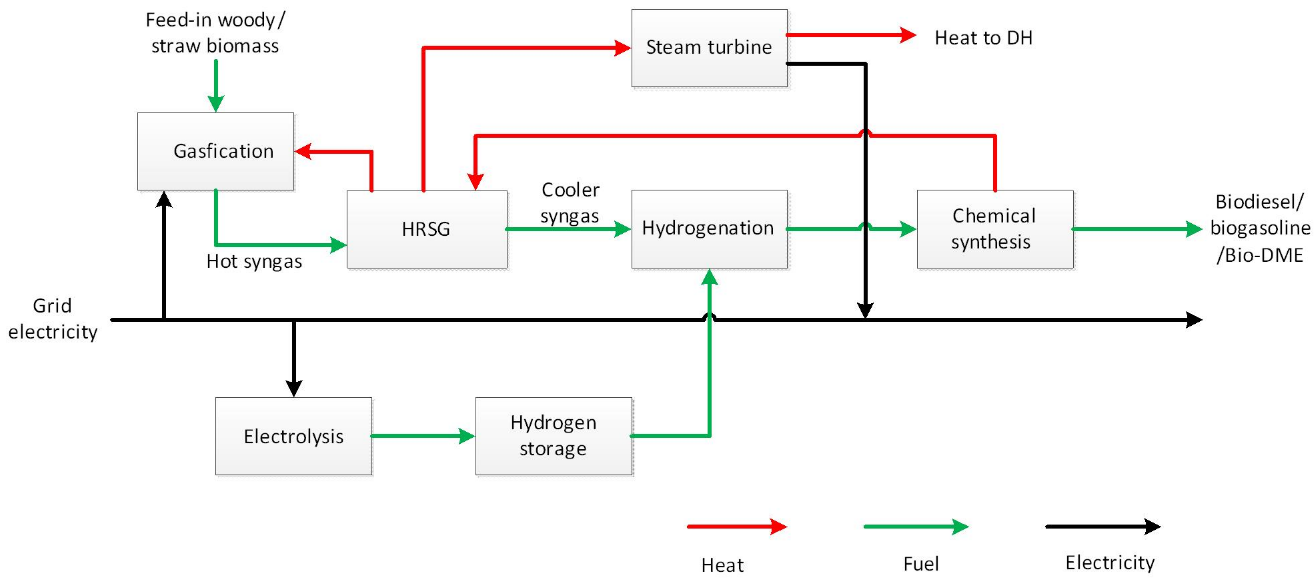

Fig. 3. Energy flow and schematic diagram of a biorefinery based DH system.

ifications. Experimental studies show that DME/diesel blends of 10-30% could be possible without a significant impact on engine performance [18,19]. For our analysis, biodiesel and DME are assumed to be mixed with conventional diesel in the range of 2-20%. For the same reason, biopetrol is assumed to be mixed with conventional petrol in the range of 2-20%. The performance of the chosen technologies is shown in Table 2. As of 2014, there were only 640 EVs in the region, so, in the model, the penetration level is bounded by an upper limit of 2,400 vehicles at the end of 2030. This is in accordance with the current annual market penetration rate.

3.5 Electricity and heat demand forecasts

The energy consumption trend in the household sector, as shown in Fig. 4, between 1960 and 1990 and 1990 and 2012 is somewhat different and resembles that of a linear and a logistic growth, respectively. A low per capita living area, reduced energy use per floor area, and a mild climate are considered to be the main driving factors for the reduced growth rate since the late 1980s [20]. The household sector is at its late development stage while the service and industry sectors are at their early development stage and expected to grow in the years to come. Econometric methods, trend methods, time series methods, end use methods, and neural network techniques are some of the well-known forecasting methods [21–24]. The choice between the methods depends solely on the purpose of the study, data availability, and timeframe. And also, in a fully unconstrained supply or excess supply condition, as is the case in Inland, demand forecast uncertainties have lesser effect on the production mix and the energy system at large. Therefore, as shown in Fig. 4, a time series approach based on the historical data has been used to forecast the annual electricity demand in Inland up to 2030. Goodness of fit has been used as an optimizing criterion for the logistic curve fitting using a Fibonacci technique method developed in Matlab.

For heat and transport demand forecasts, an end use or appliance saturation method with an assumed zero income elasticity of demand has been used. Population growth is the most important, but not the only, driver for estimating the heat demand growth using an end use method. County level population growth forecasts from Statistics Norway (SSB) have been used as the main forecast parameter. The product of intensity (kWh/m^2) and activity (area in m^2) would give us the heat demand for each building category [6]. Similarly, the transport demand is based on an annual road traffic volume (vehicle-km) forecast. The intensity or annual mobility per vehicle for the whole study period is assumed to be constant (zero income elasticity). The intensities for the existing building stock and vehicle stock have been calibrated based on the reference year 2009. The heat and transport demand forecast formula collections and results are given in Appendix.

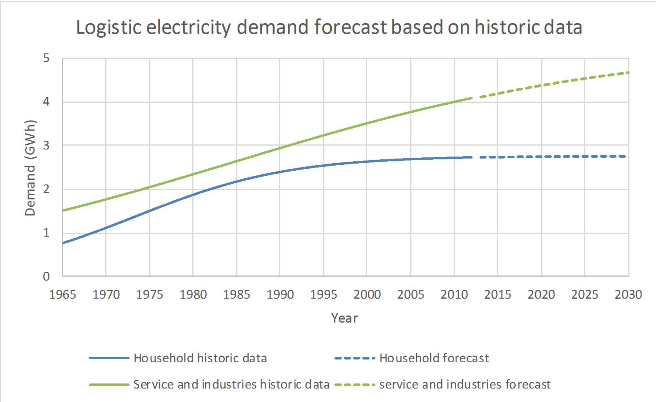

Fig. 4. Inland electricity demand forecast by sector-up to 2030.

Although we could not find any official DH production and future expansion data, the DH projects approved as of 2015 (shown in Table 1) show the annual production to be 994 GWh. For the purposes of this analysis, we allocated 0.5 TWh demand as of 2015, assumed to increase linearly up to 1 TWh at the end of the model horizon (2030).

3.6 Renewable energy potentials

The hydropower potential is explored extensively. Nationally, more than 60% of the potential is already developed (the corresponding figure in Inland is 9.28 TWh or 2095 MW) while 20% is located in a permanently protected areas. Of the remaining 20% technically feasible potential, the share in Inland for a small-scale development is found to be 1.65 TWh or 397 MW [15]. Accordingly, the upper investment bound, in our model, is set to 400 MW. Similarly, so far 715 MW wind power plants have been approved for installation and we have accordingly distributed 305, 235, and 175 MW capacity to be invested in the model in 2020, 2025, and 2030, respectively, with an annual capacity factor of 31%.

Forest-based resource is the main biomass source in the studied region and this source is subject to competition with the forest industries. Of commercial roundwoods, only pulpwood is currently found to be competitive for bioenergy use. Therefore, the source of biomass is assumed to be wood chips (pulpwood and logging residue), firewood, wood pellets, and briquettes. Previous studies have shown the forest-based and putrescible sustainable biomass potentials to be 5 TWh and 1.5 TWh, respectively [11,25]. More than 50% of Norways forest resource is located in Inland, and constitutes more than 43% of the total annual harvest in Norway [11,12]. Historical time-series annual growth increment and annual roundwood harvest data were used to construct the normal distribution of pulpwood and firewood supply. Considering a 95% confidence level, the sustainable yield (annual increment-annual roundwood cut) for each species and its average price (based on roadside price, transport, chipping, storage, and administration costs) have been calculated. Therefore, based on their price level and volume (upper bound), in the model, we have three woodchip classes, i.e. pine pulpwood (class 1), spruce pulpwood (class 2), and broad-leaved pulpwood and logging residues (class 3). Pellets and briquettes are import commodities in the model.

In a previous study, small scale solar thermal for residential application was found to be feasible in this region [26]. It could supply up to 50-60% of the hot water energy demand for a residential application [26].

3.7 Data source and assumptions

The cost of power plants, biorefineries, individual and central heating plants, and other end-use devices for the years 2015, 2020, and 2030 is taken from [27,34] and the details are given in Table 3 and Table 4. The modeled system is assumed to have bilateral trade with a single external region where trade in energy commodities and resource trades creates additional income for the system. Biomass, biofuel, and electricity trading is in the model incorporated at exogenously given prices. Heat demands are fixed, but the model has some flexibility to invest in energy conservation measures (insulation). The available biomass and price are divided into classes, which to some extent makes the biomass supply function price sensitive. Fossil fuels are import commodities and their future prices are in accordance with IEA 2015 forecasts [35]. The details of fuel prices for the base case, resource upper bound, and energy and emission taxes as of July 2015 are shown in Table 5. The biofuels at filling stations are assumed to be sold at the same price as their substitutes (diesel and petrol) for sustainable market competition. The distribution cost of biofuels, including both compression to liquid and transportation (truck) to filling stations, is assumed to be the same as that of their counterparts (conventional fuels). The basis for this assumption is previous studies [6,36]. Based on regional data, the DH system's transmission and distribution cost is assumed to be 173 €/MWh [12]. All active national

[6] Detached house, house with two dwellings, row house, linked house and house with 3 or 4 dwellings and multi-dwelling building. Formula collections, for activity (area in m^2) estimation, are given in Appendix A.

Table 3
Investment and fixed and variable operation costs of power plants and heating technologies for the year 2015, 2020, and 2030 [27,28].

Technology	Efficiency	Inve.cost (M€/MW)	Fixed O&M [a]	Lifetime (year)
Power plants				
Hydro power	-	1.76	1%	40
Onshore wind power	-	1.4/1.32/1.22	2.5%	20
District heating				
Heat pump-ground source	3.6/3.7/3.8	0.68	1%	20
Bio-heat boiler	85	0.8	2.5%	20
Gas boiler	97	0.1	3.7%	35
Electric boiler	95	0.08	1.38%	20
Biomass CHP	32 [b]	2.6	1%	30
DH transmission & distribution network	90	48 [c]	2%	30
Individual heating [d]				
Heat pump-Ground source	3.3/3.5/4	2.3/2.2/2.1	0.6%	20
Heat pump-Air source	2	1.3/1.3/1.2	0.6%	20
Bio-heat boiler	80/87/91	0.64/0.64/0.75	0.3%	20
Wood stove	65/70/75	0.56/0.6/0.67	0.01%	24
Oil boiler	90	0.29	3.5%	20
Electric heating	98	0.8	1.25%	30
Solar thermal		1.28/1.21/1.09	0.75%	20/25/30
Electrolyser	66/68/70	1.4/1/1	4%	20/25/30
Hydronic heating system	98	0.67	1%	20
DH substation	95	0.086	5.8%	20

[a] Cost is given as % of Investment cost (M€/MW/yr.)
[b] Condensing mode efficiency 32%, heat to power ratio 2.4, and electricity loss to heat gain ratio 0.15
[c] Cost is given in M€/PJ
[d] All heating plants investment cost is given as (M€/MW$_{th}$)

Table 4
Process efficiency, Investment, and fixed and variable operation costs of Biomass gasification-based biofuel technologies for the year 2015.

Technology [a]	Efficiency [b] (%)	Invest. cost (€/GJ)	Fixed cost (€/GJ/yr.)	Life time (years)	Reference
DME	53/0/35	43.7	1.3	20	[29]
FT-diesel	58/2.5/18	113	3.4	20	[29]

[a] Biorefinery plants cost given as €/GJ. The technologies are available at discrete capacity levels. For modelling purposes, we have used a proportionality factor of 0.70 for all technologies. Meaning that doubling the size of plant would increase the investment cost by 62%.
[b] The efficencies are given in the order of biofuel/electricity/heat)

policy measures and energy taxes (as of July 2015) are kept constant throughout the model horizon. The discount rate is assumed to be 5%. The tradable green certificates price for new power plants is assumed to be 25 €/MWh.

3.8 The TIMES-Inland model

The integrated MARKAL-EFOM (Market Allocation Energy Flow Optimisation Model) system or TIMES is a generic energy system model generator and optimization tool comprising the entire energy system, i.e. the electricity, heat, and transport sectors [37]. It is a partial equilibrium linear programming optimization model. The objective function minimizes the total discounted system cost for the whole modeling period and maximizes societal welfare (consumer and producer surplus) of the system at different temporal time resolution. This makes TIMES suitable for long-term planning with perfect foresight. In addition, it helps to analyze the impact of market measures and energy policies on technology mix, fuel mix, emissions, and cost to energy system.

TIMES has been used extensively for long term energy planning at regional and national level, for example to analyze the optimal renewable energy production mix in Norways future energy demand [38], to study cost-effective electricity sector decarbonization opportunities in Portugal by 2050 [39], to model buildings decarbonization with application in China [40], to model decentralized heat supply [41], to model household energy use behavior and heterogeneity [42], and the impact of carbon capture and storage on the electricity mix and the energy system costs [43]. In addition, the tool has been used to

Table 5
Fuel prices for the year 2009, 2015, 2020, 2025, and 2030, respectively [30–33]

Fuel	Price (€/GJ)	Upper bound (PJ)	Road usage/Energy tax (€/GJ)	CO_2 tax (€/GJ)
Electricity	9.34/9.49/9.61/9.73/9.85	-	5.7/18.3	-
Diesel	12.26/14.08/18.69/21.45/24.63	-	10.25	3.32
Petrol	15.62/16.98/22.54/25.88/29.71	-	16.53	3.22
Natural gas	3.53/4.35/5.77/6.62/7.61	-	1.82	-
Heating oil-light	16.12/23.16/30.74/35.29/40.52	-	5	-
biodiesel	12.26/14.08/18.69/21.45/24.63	-	4.34	-
biopetrol	15.62/16.98/22.54/25.88/29.71	-	4.34	-
Wood chips (spruce) [a]	6.07/5.45	8.1	-	-
Wood chips (pine)	4.92/4.58	2.43	-	-
Wood chips (broad leaved and logging residues)	4.18/4.32	10	-	-
Fuelwood	3.94/4.32	-	-	-
Wood Pellet	12.74/11.62	-	-	-
Briquettes	9.36/11.44	-	-	-

[a] For the base case simulation, all wood chips, fuelwood, pellet and briquettes are assumed to have a constant price from 2015 onwards. The biomass price is kept constant as the level of harvest is very low and, in the short run, a supply increase could offset the incremental costs that may arise by increase in demand.

simulate a fine time resolution model to show that the use of a low time resolution would result in an overestimation of investments in highly fluctuating renewables (wind power), and the results have been validated with measured data [44].

Due to the limitations on computational capability and time, it is important to identify the critical time periods in each year so as to capture the supply and demand dynamics of the energy system. Given the fact that hydropower is the main source of power supply, production is greatly affected by seasonal inflow variations. Electricity is the main commodity in Inlands energy system, both for electricity-specific consumption and heating purposes. The electricity and heating demands will therefore also vary, mainly on a seasonal, daily, and hourly basis. The diurnal variation is due to peak and off-peak hour demands. We have therefore divided the year into four seasons (autumn, winter, spring and summer) with each season represented by an average diurnal distribution (24 hours). We thus have a total of 96 time slices. The seasonal time slice captures resource availability (hydro inflow and solar radiation) and seasonal demands (associated with heating), the daily time slice enables us to analyze storages (hydrogen and thermal storages) and time-specific residential and industrial consumption. The hourly wind power production profile is taken as the weighted average of four locations. The residential and district heat demand normalized profiles are estimated based on measured heating degree days (HDD) in the region. The seasonal and annual availability of capacity, efficiency, and load distribution profiles of each commodity are some of the inputs to the model. TIMES special features enable us to model the time dependence of the availability of process input energy carriers and efficiency.

Fig. 5 shows the general modeling approach we have followed in TIMES-Inland model. There are three regions: (1) import-export market region IMP/EXP; (2) renewable energy resources mining region MINRENEW; (3) the system being modeled or Inland region. The result interpretations are in the light of Norways national energy system.

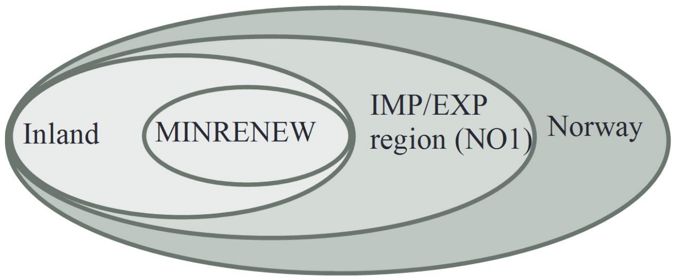

Fig. 5. Internal (Inland) and External (MINRENEW and IMP/EXP) modeled regions.

3.9 Model scenario and sensitivity cases set up

The electricity price, including its seasonal variation, would greatly influence bioenergy technology investments. The base scenario holds all the existing prices, probable future forecasts, and active policy measures. The electricity price development is in the base scenario assumed to follow coal price development (IEA 2012 forecast) as the variable cost of marginal condensing power plants is a major price driver in the Nordic electricity market. The annual incremental rate is 0.25% from 2015 to 2030 [45]. In the base case, the biomass price is kept constant as the level of harvest is very low and, in the short run, a supply increase could offset the incremental costs that could arise by increase in demand.

Alternative scenarios and sensitivity tests are equally important as stochastic simulations to study the systems response to certain impact parameters. In this regard, as shown in Table 6, three alternative matrix scenarios, SC-1, SC-2, and SC-3, with an annual electricity and biomass price escalation rate of 2.5% have been considered. Further, the scenario cases are tested for a biofuel subsidy. The biofuels subsidy level required to initiate investments has been found through iteration.

Sensitivity cases are drafted based on scenario case results. The COP of ground source and air source heat pumps (which depends on several conditions like ambient air temperature, ground temperature, soil and rock type, and installation standards), investment cost of biorefineries (immature technologys investment cost is most likely to decline due to technology learning), and hydronic distribution systems (which replace direct electric heating systems with a waterborne heating systems) are the selected sensitivity parameters. The details are presented in Table 7.

Table 6
Model scenarios based on electricity and biomass price

Senarios	Description
Base case	Base electrity and biomass price
Scenario-1	Base electricty price and high biomass price
Scenario-2	High electrty price and base biomass price
Scenario-3	High biomass and electrity price

Table 7
Sensitivity cases and naming

Sensitivity cases	Description
COP25	Lowering the seasonal COP of heat pump during winter and spring seasons by 25%
BioREF25	25% Lower biorefineries investment cost compared to the reference
HYD50	50% higher hydronic heating (radiators) systems investment cost compared to the reference

4 Results

The objective function minimizes the total discounted system cost of the whole modeling period and maximizes societal welfare or the social surplus of the system at different temporal time resolution. For our analysis and discussions, technology mix and production are of greater interest than the optimized discounted system cost. With this understanding, the scenario results and sensitivity analysis are presented in the following sections.

4.1 Scenario comparison

The system optimized heating demand technologies production mix for each milestone year (model decision year) of the base and scenario cases are shown in Fig. 6. The technology mix and its diffusion as it progress towards the model horizon seems to be a well distributed and a realistic representation. This is primarily because of the disaggregated demand levels, as many as eight in the residential sector and five in the service sector, and limited access to technologies at those demand levels to avoid a sudden technology shift in the technology mix, as verified in [42]. Wood stoves and air-to-air HPs were made available for investment with an upper bound of 50% (of the space heating demand). As can be seen from Fig. 6, efficient wood stoves in the residential and water-to-water HPs in the service sector are dominantly invested in in all cases except SC-1, where high biomass price and low electricity price favor air to air HPs over bioheat boilers and water-to-water HPs. Similarly, solar water heating was made available for investment with an upper bound of 62% (of hot water demand), but was found to be uncompetitive primarily due to its low capacity factor. The share of individual and central heating demand technologies reduces as the DH supply increases. This is because, in the model, DH is a chosen technology, not a competing technology. However, the central plants in DH are subjected to competition. The high residential electricity tax reduces the share of electric heaters and they are replaced by HPs, which are seemingly paid for through their high year-round efficiency. The increased efficiency seems to offset the high replacement cost of direct electric heaters. However, a great many water-to-water HPs are invested in in the service sector central heating systems that have a hydronic system. This suggests that hydronic distribution cost is the determinant factor for the replacement of direct electric heaters in the residential sector. Moreover, as noted in SC-1, when biomass price increases at a rate of 2.5%, many wood stoves are replaced by air-to-air HPs, suggesting that the merit order, if not water-to-water HPs, is wood stoves followed by air-to-air HPs.

Bioheating shows quite low penetration in the residential sector due to a high pellet price, but a large part of it fired by wood chips in industries is found to be cheaper than oil and electric boilers. As seen in Fig. 6, bioheating is found to have increased by 72% for all scenarios by 2030. If wood chip storage were not a problem in residential and service sector buildings, we would have seen a high penetration rate.

The planned DH central plants are assumed to be exogenous investments made in 2015, based on Table 1. In 2015, wood chip bioheat boilers supply the base and bulk loads while gas and electric boilers supply the peak load. In an optimized system, DH central plants heat production mix without biofuel subsidy is shown in Fig. 7. As can be seen, no biorefinery investments are made, primarily due to the high investment cost. Instead, CHP and HPs replace bioheat boilers and dispatch a large part of the DH demand in all scenarios as the existing bioheat boilers depreciate towards 2030. CHP is found

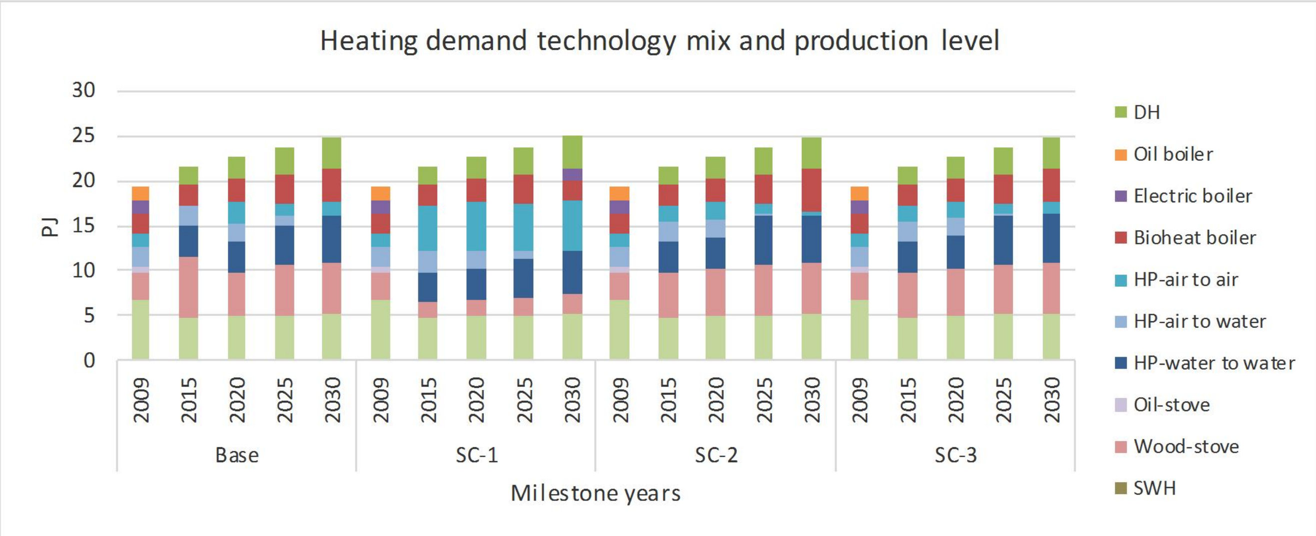

Fig. 6. Heating demand technology mix and production level in all sectors.

to be profitable only at a high electricity price, showing that electricity price is the most determining factor for CHP deployment in DH. The minimum being 9.85 €/GJ by 2030, as shown in Fig. 7 for the base case. In SC-2 and SC-3, CHP covers more than 29-46% of the DH demand. The share is directly proportional to electricity price. As electricity price increases, CHP production also increases, whereas increasing the biomass price will increase the heat production share of HPs, as shown in the base and SC-1 cases. However, the fact that if biomass price hovers at the current level, a high electricity price favors both CHP and bioheat boilers can be noted by comparing the base and SC-2 cases. As opposed to other scenarios, in SC-2 bioheat boilers have not been fully depreciated towards 2030. Instead, new investments were made in 2030.

In the model, the upper activity limit for biofuel production of biorefineries is driven by the available heat sink capacity or base and bulk load. The plants are available at discrete capacity, which is 1.97 PJ/year for the DME and 1.95 PJ/year for the FT-biorefinery. The higher the sink capacity the more plants would be invested in. The specific investment cost of the DME biorefinery is lower than the FT-biorefinery, but the high biogasoline price (and hence revenue) of the FT-biorefinery tends to level out the incremental costs and it is difficult to make a clear distinction of the cost advantage unless such a system perspective optimization is made. The model runs were made at different biofuel subsidy levels. Fig. 8 shows the heat production share at their corresponding minimum biofuel subsidy level to initiate investment in biorefineries. Using iteration, the subsidy level and chosen technology were found to be 6 €/GJ and DME-biorefinery for the base and SC-1 cases and 12 €/GJ and FT-biorefinery for the SC-2 and SC-3 cases. The results are broadly in line with previous studies [5–7] although they are limited to the district heating sector. Increasing biofuel subsidy further will increase the number of plants and heat production share until the available heat sink capacity is saturated. In both cases, a single plant investment was made. Depending on the DH demand level, the maximum heat production share of both biorefineries is found to be between 17% and 26%. Comparing DH production with (Fig. 8) and without biofuel subsidy (Fig. 7), the distribution is in the same order except that biorefineries replace part of the load that would otherwise be covered by CHP and HPs. The results suggest that, at higher electricity and biomass prices, both biorefineries are uncompetitive compared to conventional heat sources (CHP and HPs), and require a higher biofuel subsidy. That being said, FT-biodiesel is more profitable than DME.

It is worth mentioning that when we remove the coexistence of tradable green certificates (TGC) and biofuel subsidy or with zero TGC, the biofuel subsidy shows a marginal decrement of 1 €/GJ for SC-2 and no change for SC-3. There is some interaction between the two, and of course, the EU Renewable directives and Norway-Sweden TGC agreements indirectly force both to coexist. That being said, the CHP has been completely replaced by bioheat boilers and HPs in SC-2 and SC-3, respectively. This shows that even at a high electricity price CHP is not profitable without TGC.

In the model, biodiesel and biogasoline are used in passenger and light-duty vehicles (LDV) (higher demand) while DME is used in buses and heavy-duty vehicles (HDV) (lower demand). The biofuels are blended in a standard vehicles, excluding fuel flexible vehicles, as standard vehicles would continue to dominate even after the model horizon. Fig. 9 shows the total fuel use distribution in all scenarios. As can be seen from the

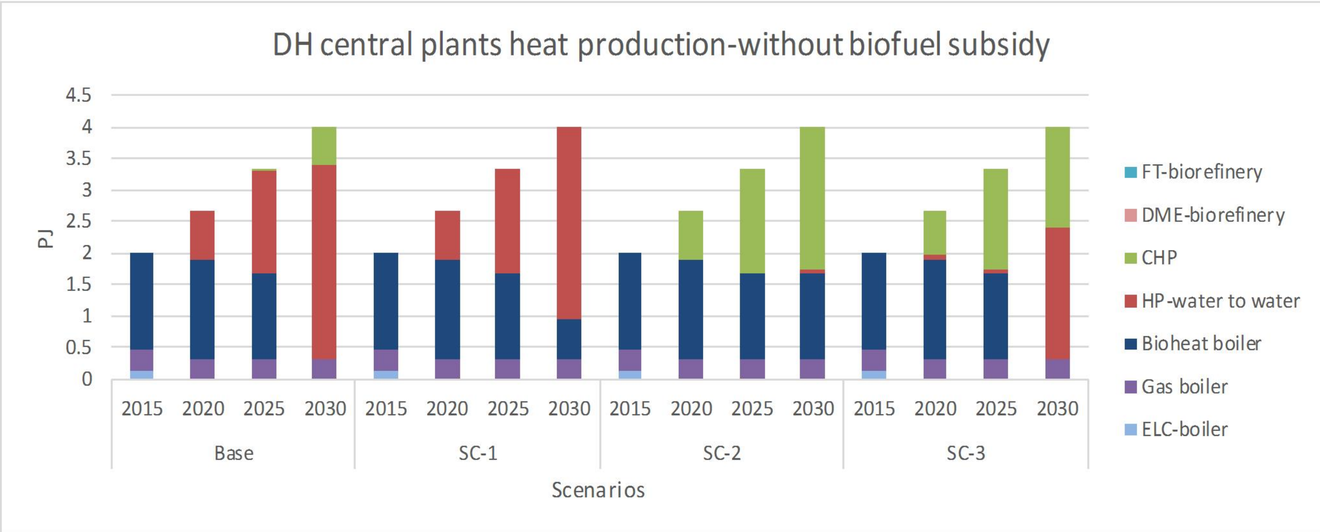

Fig. 7. DH central plants' heat production mix without biofuel subsidy.

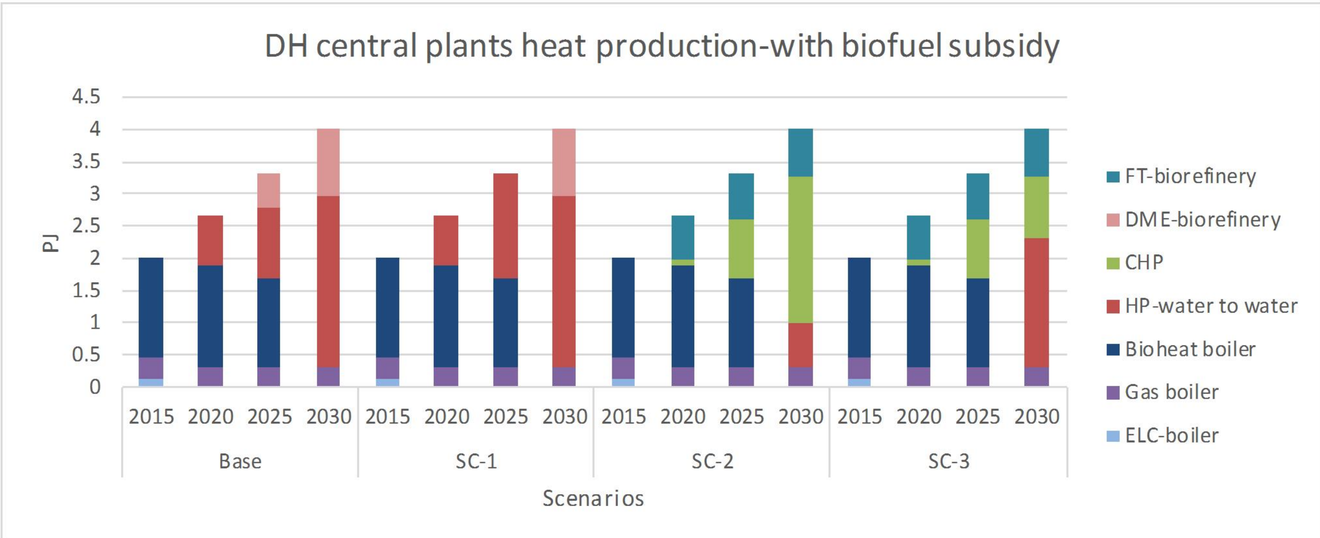

Fig. 8. DH central plants and production mix with biofuel subsidy.

figure, the upper limit of 20% is effectively used by biofuels, if not produced, imported. This is mainly because of the high road usage and CO_2 taxes imposed on diesel and petrol, as shown in Table 5. By 2030, for the base and SC-1 cases DME is a net export as the demand is only 0.41 PJ while production is 1.57 PJ. Similarly, for the SC-2 and SC-3 cases biodiesel and biogasoline are net imports as the demand is 2.8 PJ and 1 PJ while production is 1.69 PJ and 0.7 PJ, respectively. This implies that only 60-70% of the upper 20% blending limit is covered by produced biofuels; the rest is imported. However, this depends on the price of conventional diesel and petrol used for price setting in our model. The higher the price the less subsidy is required to make such plants profitable.

The implication is that the assumed DH demand would be enough to achieve the 10% RES share target in the transport sector. Furthermore, if we consider the EU Renewable directives' (2009/28/EC) accounting method, the share would be more than double [7]. No investments were made in hydrogen fuel cell vehicles (HFCVs), primarily due to their high vehicle cost, but a total of around 2,400 electric vehicles (EVs) were invested in at the end of 2030. Due to their high efficiency (7 km/kWh), electricity consumption is not visible in Fig. 9 and EVs'

[7] The directive counts every unit of TWh second-generation biofuel as 2 TWh as long as the biofuels are produced from waste, residue, non-food cellulosic material, and ligno-cellulosic material.

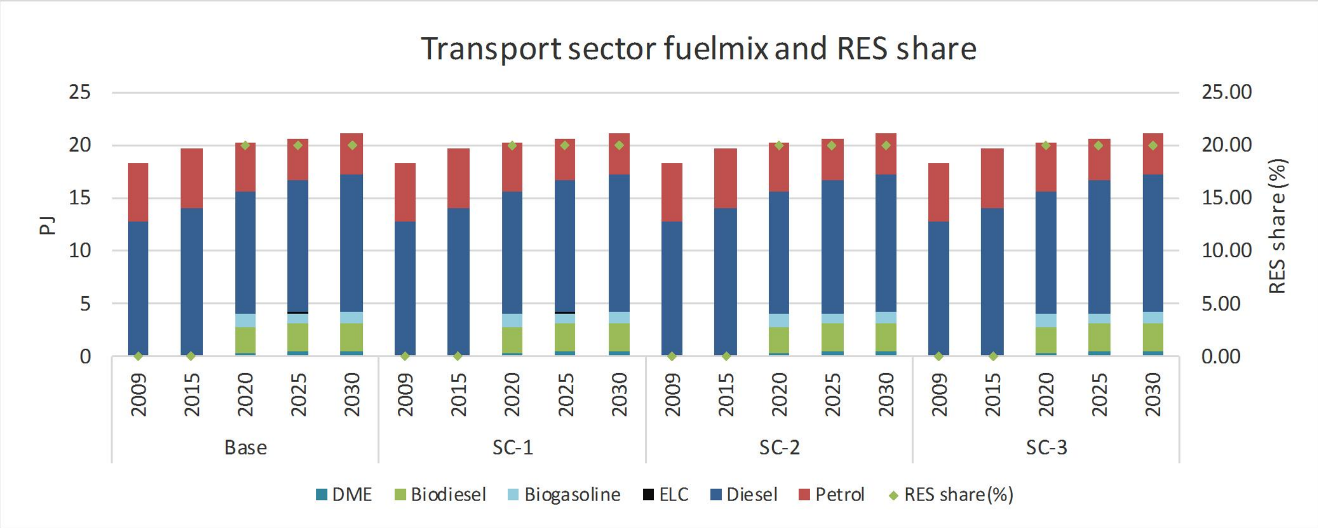

Fig. 9. Transport sector fuel mix and renewable energy sources (RES) share.

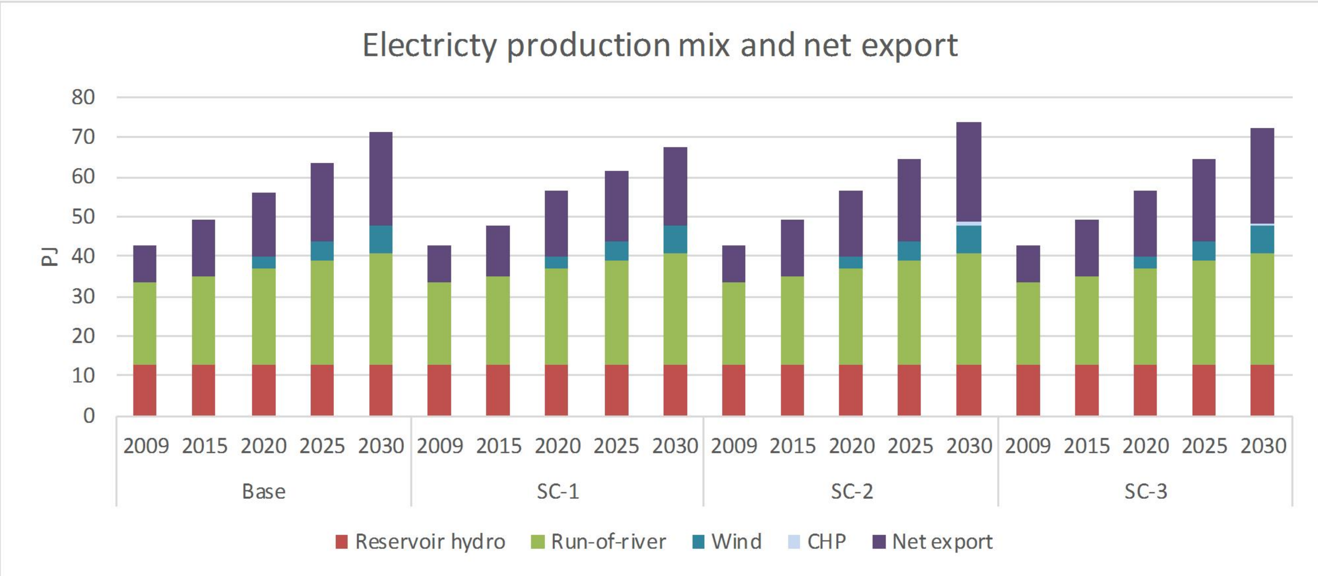

Fig. 10. Electricity production mix and net export.

contribution to increased RES share is therefore insignificant.

4.2 New power plants investments

In addition to CHP, investment in wind power and small-scale hydropower is found to be profitable at higher electricity prices, and these constitute a net export as the system is in excess even in 2009. As shown in Fig. 10, all the available 400 MW small-scale hydro and 715 MW wind power are invested in. Although not shown here, the same investments were made even without subsidy or TGC. This is primarily due to the assumed high electricity price. Apart from their market value, new power plants contribute to national energy system power supply security. In fact, biorefinery investments contribute to reduced net exportable electricity as electricity is used for hydrogen production which would otherwise be covered by additional biomass consumption.

In a Nordic electricity market import-export context, the price is sensitive to volume and tends to increase the export region price and decrease the import region price, which in turn would have an impact on bioenergy competitiveness. However, this effect has not been considered here due to the fact that both regions share the same market region (NO1).

4.3 CO_2 emission

From a CO_2 emission perspectives, as of 2009 the transport sector is responsible for more than 70% of the total emissions in Inland. Despite the increased transport demand, as shown in Fig. 11, a significant emission reduction can be observed after 2015. Diesel vehicles are efficient and less polluting (in terms of CO_2 emissions) than petrol vehicles although particulates and other toxic emissions like NO_x are noticeably higher. To mimic reality we have limited the upper activity limit of diesel vehicles to 60% (60% of the transport demand would be covered by diesel vehicles). As a result, we have seen a fairly constant emission level after 2020 as the increased transport demand is partly offset by increased vehicle efficiency.

Furthermore, in addition to the local emission reduction, as shown in Fig. 11, if we consider the exportable green electricity that could potentially displace marginal condensing power plant in Nordic electricity market, the global emission cut would be substantial.

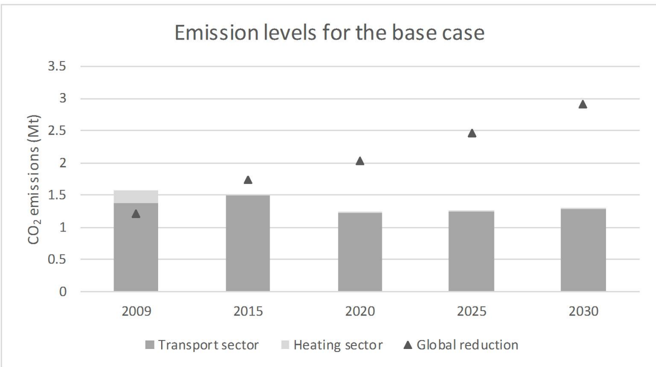

Fig. 11. CO_2 emission levels for the base scenario case. The sources are fossil fuels used in road transport and heating boilers. The global emission reduction is due to the exportable green electricity assumed to replace condensing power plants with an emission factor of 450 g/kWh.

4.4 Sensitivity analysis

Based on scenario results, three sensitive parameters were selected: Hydronic distribution cost, seasonal COP variation, and biorefinery investment cost. Fig. 12 shows hydronic distribution cost sensitivity results. In all scenarios, a 50% investment cost reduction for the hydronic distribution system enabled, on average, an 11% increment in waterborne heating system penetration (9% in the residential sector and 2% in the service sector) and reduces the air-to-air HPs' share by 25%. However, mostly water-to-water HPs were invested in instead of bioheat boilers. This shows that a hydronic heating system is not the only factor for low bioheating penetration; pellet price is also a major factor.

Similarly, as shown in Fig. 13, a 25% lower COP during winter and spring would result in a 57% lower share of air-to-air HPs and 5% water-to-water HPs while allowing a 42% bioheating and 190% wood stoves increase, which would otherwise be covered by HPs. The effect is more pronounced in air-to-air HPs, which is most likely to occur in a low temperature region like Norway. This implies that poor performance of heat pumps during cold seasons or installation errors would have a considerably greater effect on bioheating than direct electric heaters as it has a relatively stable penetration in all scenarios. Otherwise, it has an insignificant effect on water-to-water HPs penetration level.

Lastly, it has been noted that a 25% investment cost reduction in biorefneries would result in insignificant or zero impact on its DH share, or we found the same investments as in Fig. 8, but the subsidy level required to initiate the same investments was lower compared to the reference. The marginal reduction in subsidy level is found to be 2 €/GJ for the base, SC-1, and SC-2 cases while it was 1 €/GJ for SC-3, primarily due to the fact that conventional heat sources are also too expensive.

5 Discussion and conclusions

In this study, we have calibrated an electricity-intensive energy system and analyzed the long-term development of the system under various frameworks. The primary objective is to see if biorefinery technologies are competitive over conventional technologies from an overall energy system perspectives, i.e. the electricity, heat, and transport sectors.

The results suggest that bioenergy technologies like bioheat boiler, biomass CHP, and biorefinery are in strong competition with efficient HPs in individual, central, and DH systems. The main reason for low penetration of waterborne heating in the residential sector is the lack of a hydronic distribution system, but this is not the only factor for the bioheat boilers low deployment rate. Instead, pellet price is the major factor (due to lack of wood chip storage). This was noted in the existing service sector central heating system where water-to-water HPs were predominantly invested instead of bioheat boilers. To strengthen this further, in the industry sector, bioheat boilers (fueled by wood chips) were found to be cheaper than electric and oil boilers. Nevertheless, in the residential sector efficient wood stoves as replacements for old wood stoves were found to be a priority over air-to-air heat pumps, although limited to 50% of the space heating demand at most.

It is worth mentioning that, for increased bioenergy use in a DH system, CHP is found to have priority over bioheat boilers. However, if the price of biomass hovers at its current level, a high electricity price favors both CHP and bioheat boilers (as a result of fewer HPs). All

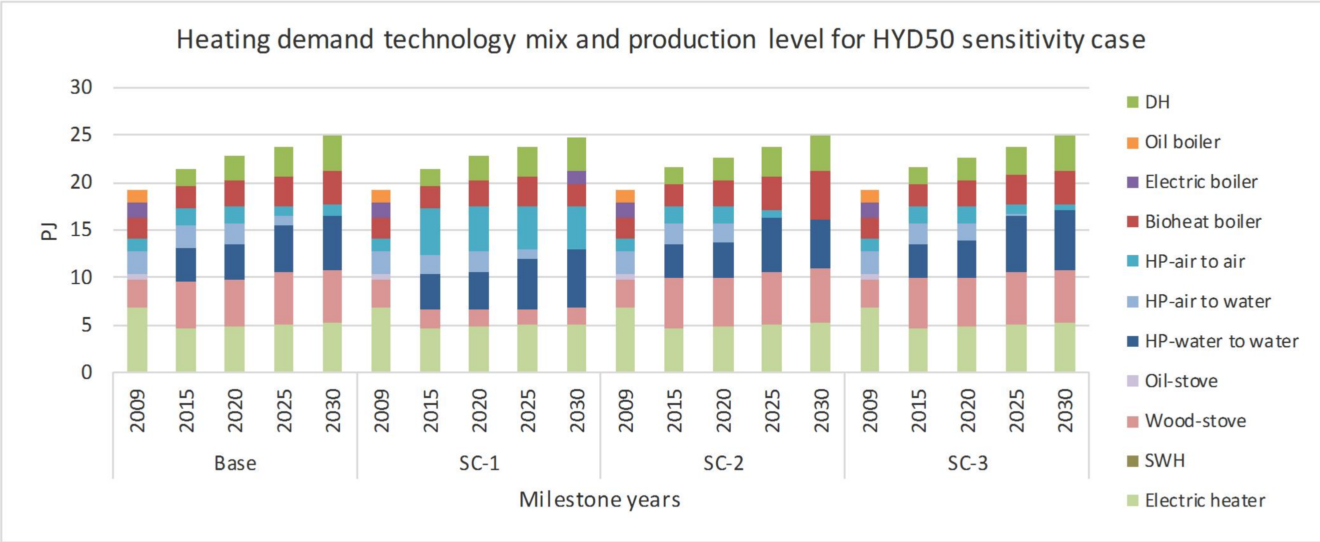

Fig. 12. Heating demand technology mix and production level in all sectors for hydronic heating sensitivity case.

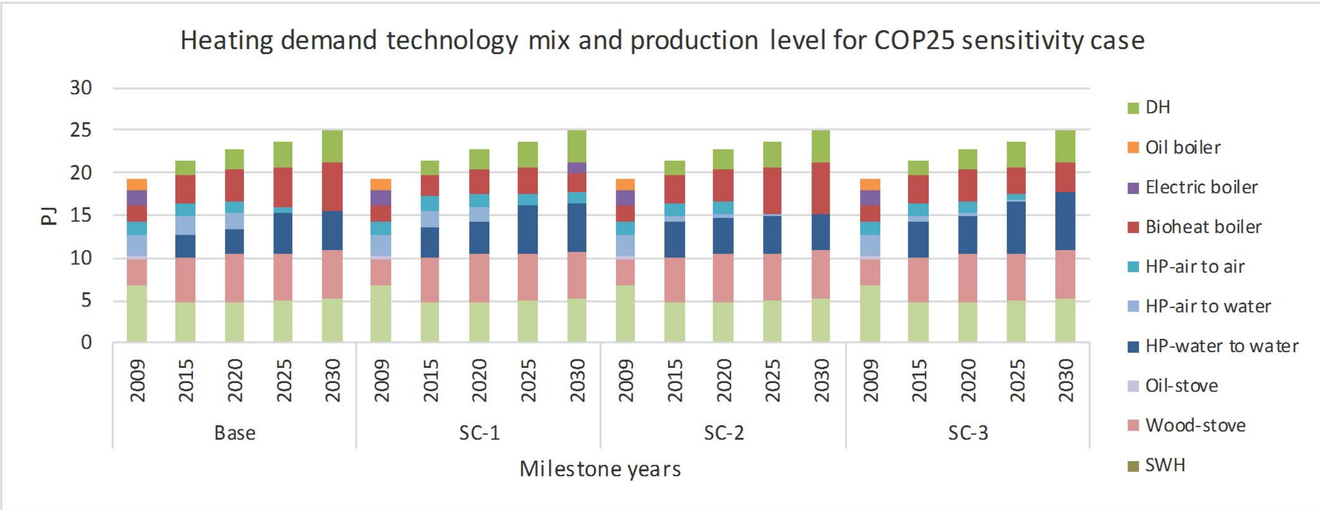

Fig. 13. Heating demand technology mix and production level in all sectors for COP heating sensitivity case.

in all, the existing DH central plant compositions have shown a complete replacement of bioheat boilers with CHP and HPs by 2030.

The fact that the production cost of biofuels is higher than the price of their counterparts diesel and petrol is shown by the level of biofuel imports. It was shown that a minimum of 6 €/GJ biofuel subsidy is required to produce biofuels equivalent to 60-70% of the upper blending limit (20% by energy) in standard vehicles. The remaining 30-40% has been imported at the set price or could potentially be covered by increasing the subsidy level until the available heat sink is saturated. However, as electricity and biomass prices increase, the required biofuel subsidy level also increases to as high as 12 €/GJ. The reverse is true if diesel and petrol prices increase as both are used for price setting in our model. By contrast, without any biofuel subsidy the same amount has been imported, primarily due to the high road use and CO_2 taxes imposed on diesel and petrol fuels.

Biorefinery and CHP are competing technologies and it is interesting to see the effect of the co-existence of biofuel subsidy and tradable green certificates (TGCs). It has been noted that when the TGCs are removed, the required biofuel subsidy shows a marginal reduction as low as 1 €/GJ. This implies that there exists a slight interaction between them. Considering a 100% renewable electricity sector, biorefinery will have a considerable impact on emission reduction, increased bioenergy use, and increased RES share over CHP. Moreover, the EU Renewable directives and Norway-Sweden's TGC agreements indirectly forces both to co-exist.

Biorefineries' integration with conventional DH depends on the available DH sink capacity. The larger the DH demand the greater the production of biofuels. In our model, the DH is quite small, only 1 TWh at the end of the model horizon, and not enough to fully utilize its economies of scale. However, the results have a positive implication for a large-scale deployment, and hence for fast technology learning and reduced specific investment cost.

Even though we have used high quality data, one major uncertainty in this study is the assumptions of future development of investment costs regarding alternative technologies. As to this, it should be noted that an increase in investment cost will have a considerable impact on the results. Specifically for biorefineries (immature technologies), in our model, an endogenous learning curve of future specific investments cost development was incorporated. However, due to the small size of the DH demand, and hence required biorefinery plant size, the effect was not fully recognized. Therefore, the investment cost is interpreted in the same way as mature technologies.

Acknowledgment

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A Appendix

A.1:Heat and transport demand forecasts

- Heat demand forecast

$$TA_{year(t,i)} = \sum_i \frac{P_{year(t)} \times A_i}{O_i}$$
$$EA_{year(t,i)} = \sum_i \frac{P_{year(2009)} \times Area_i \times (1-d)^t}{O_i}$$
$$RA_{year(t,i)} = \sum_i EA_{year(t)} \times (1-r)^t$$
$$NA_{year(t,i)} = TA_{year(t)} - EA_{year(t)} - RA_{year(t)}$$
$$HD_{year(t,i)} = I_i \times A_{(t,i)}$$

where: TA is total floor area (m^2), EA: Existing floor area (m^2), RA: Renovated floor area (m^2), NA: New floor area (m^2), HD:Heat demand (kWh/m^2), I:Intensity (kWh/m^2), A∈(EA,RA and NA): area per dwelling(m^2), O: Occupants per dwelling, i: building catagory (detached, multi-dwelling, floor size, residential, service), t:year, d:demoltion rate (%), and r: renovation rate (%).

- Transport demand forecast

$$TV_{year(t,i)} = \sum_i P_{year(t)} \times NV_{(t,i)} \times (1-s)^t$$
$$TD_{year(t,i)} = I_{(t,i)} \times V_{(t,i)}$$

where: TV is total number of vehicle, NV: number of vehicles per capita, I: annual traffic vlume (vehicles-km) per vehicle, V∈(TV): number of vehicle, TD:transport demand (million-km), i: vehicle type (Bus,passenger vehicle, light duty vehicle, heavy duty vehicle), t:year, and s:scrapping rate (%).

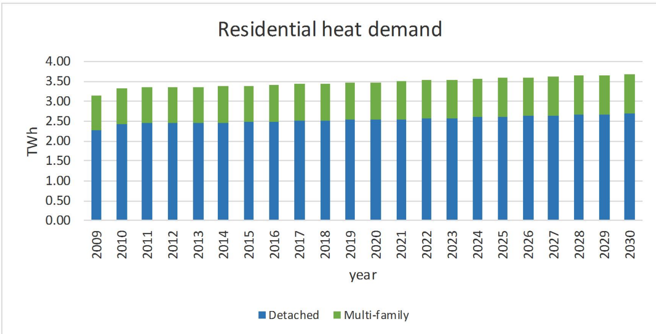

Fig. A.1. Residential heating demand forecast by building type.

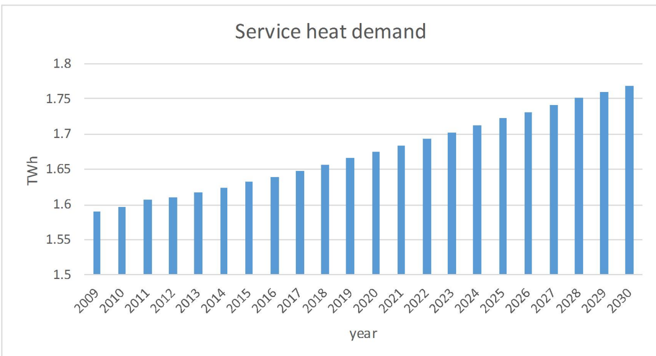

Fig. A.2. Service sector heating demand forecast.

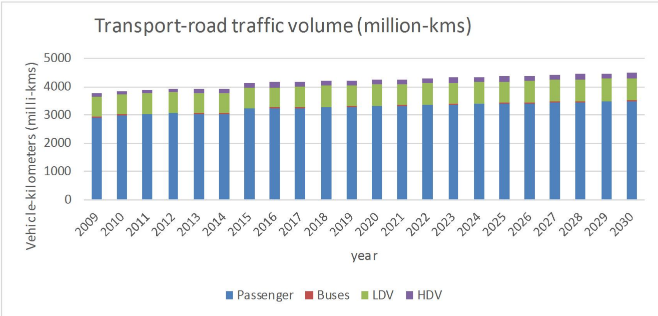

Fig. A.3. Transport demand forecast by type of vehicle.

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