Norwegian University of Life Sciences
Faculty of Environmental Science and Technology
Department of Ecology
and Natural Resource Management

Philosophiae Doctor (PhD)
Thesis 2016:67

Modeling integration of renewable energy sources into Inland Norway energy system

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

Dejene Assefa Hagos

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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].

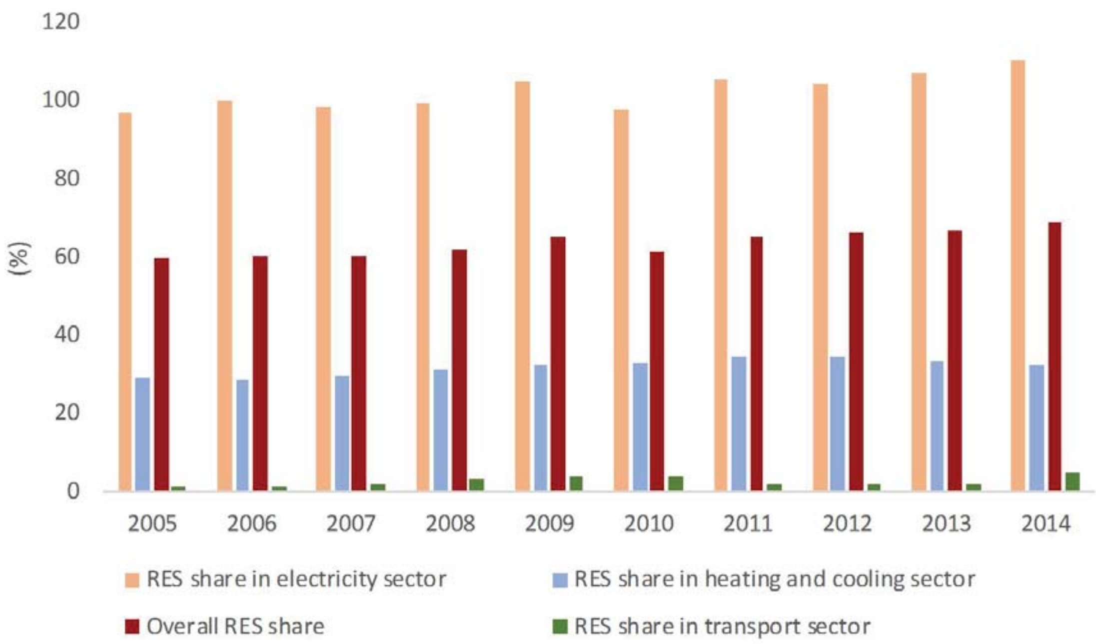

Figure 1: The share of RESs in the Norwegian energy system over the past years [6].

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].

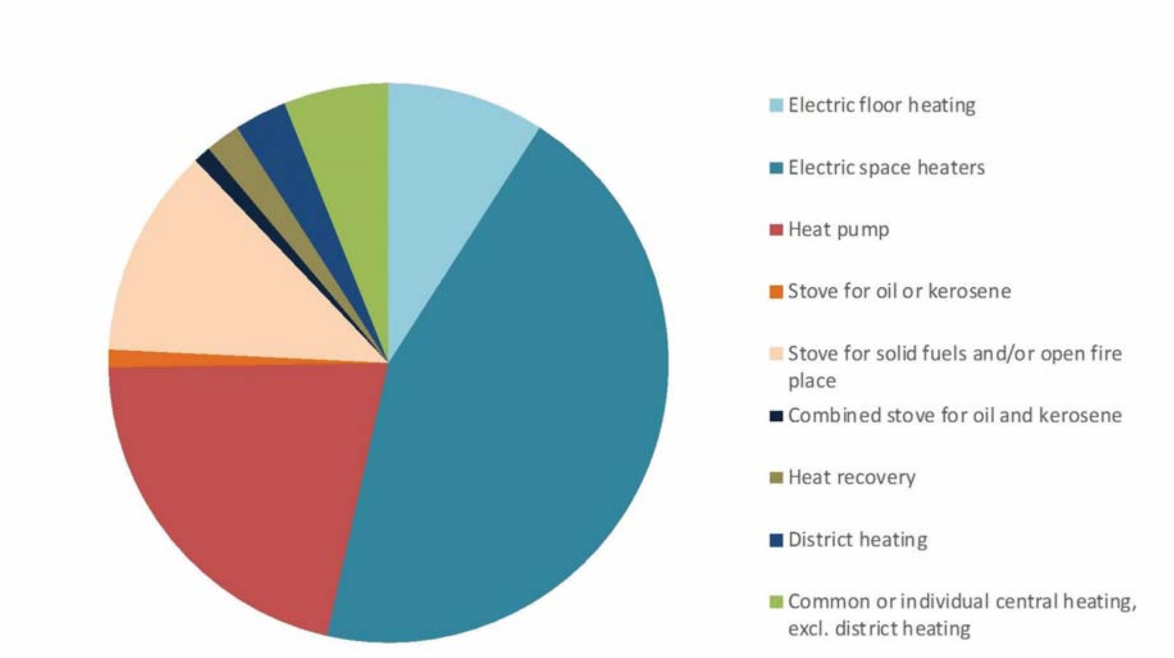

Figure 2: Households by main heating source [10].

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].

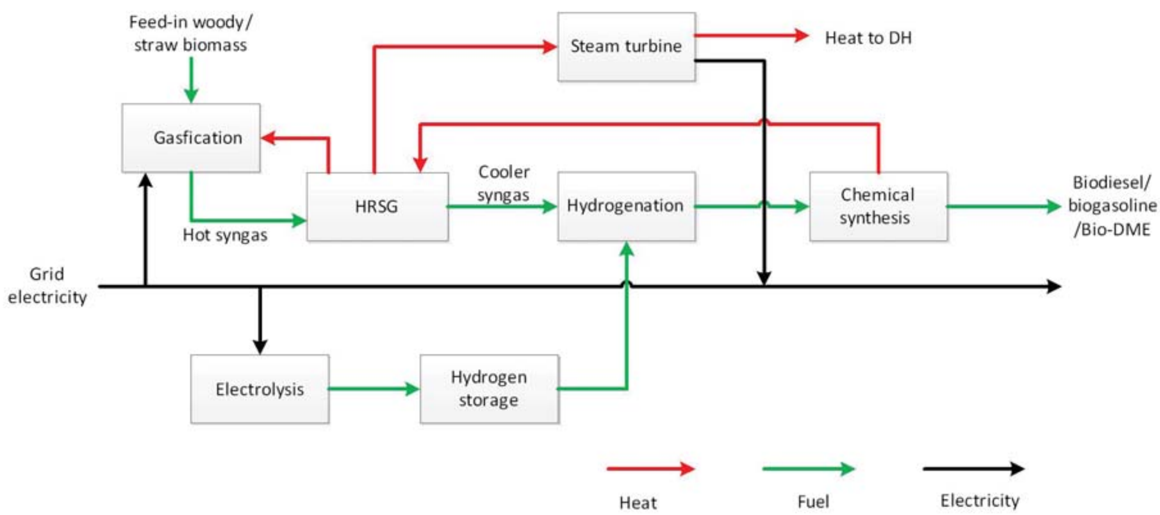

Figure 3: District heating integrated biorefinery system, working components, and energy flow diagram

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

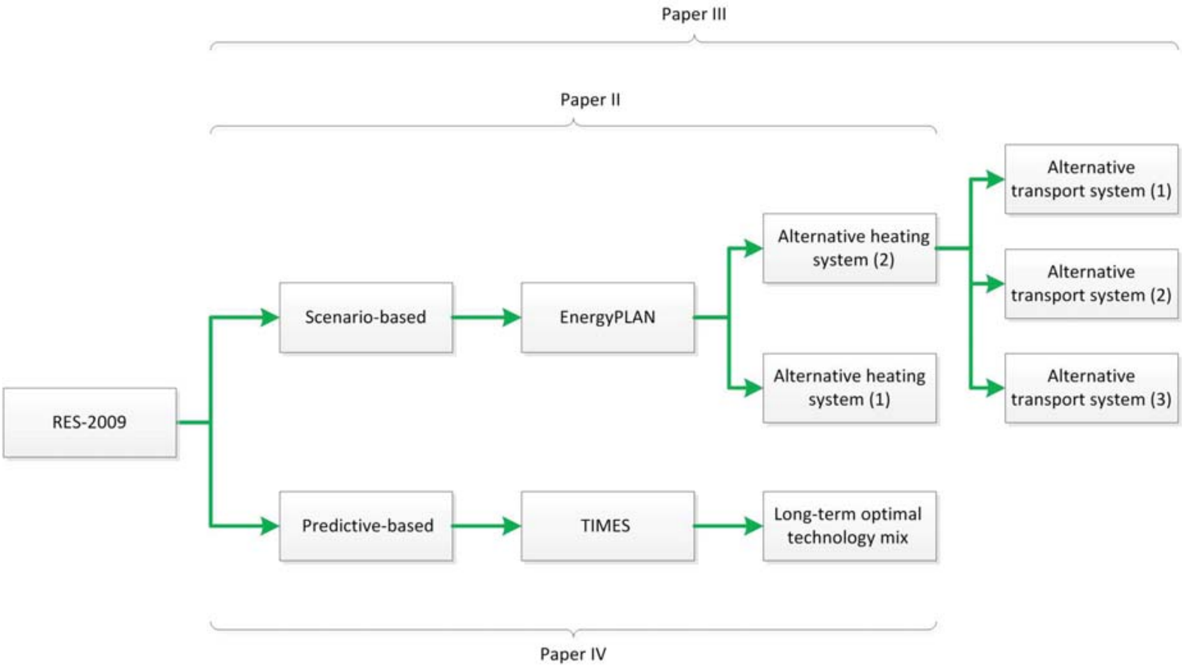

Figure 4: Theoretical framework of the study. RES-2009 refers to the reference system for 2009. The scenario-based approach (all investments are exogenous) optimises only the operation, while the predictive-based approach (all investments are endogenous) optimises both the investments and the operation. 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.

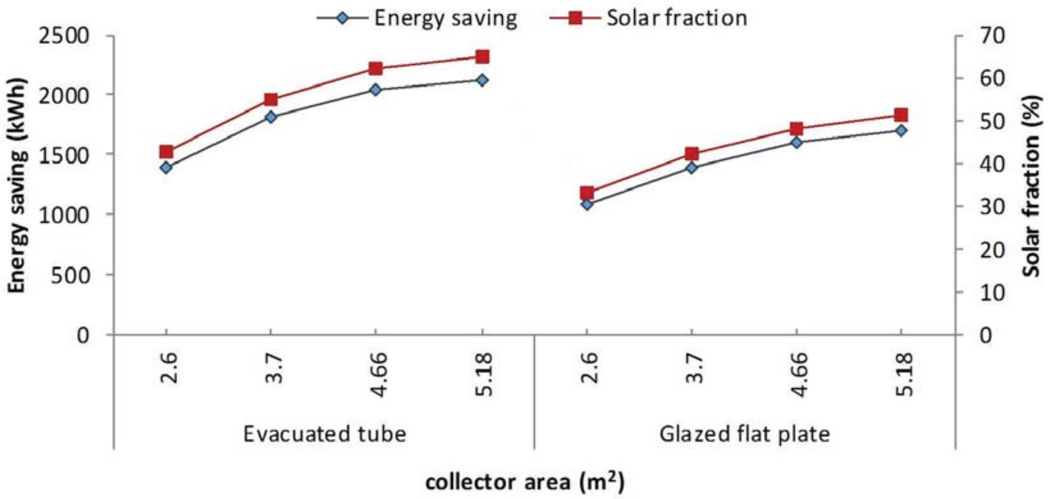

Figure 5: Annual electric energy saving and solar fraction for a series of collector area and a fixed storage capacity of 250 L. The results are taken from Paper I, but additional simulation for a similar collector area has been done to illustrate better the optimal collector area of both collector types.

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.

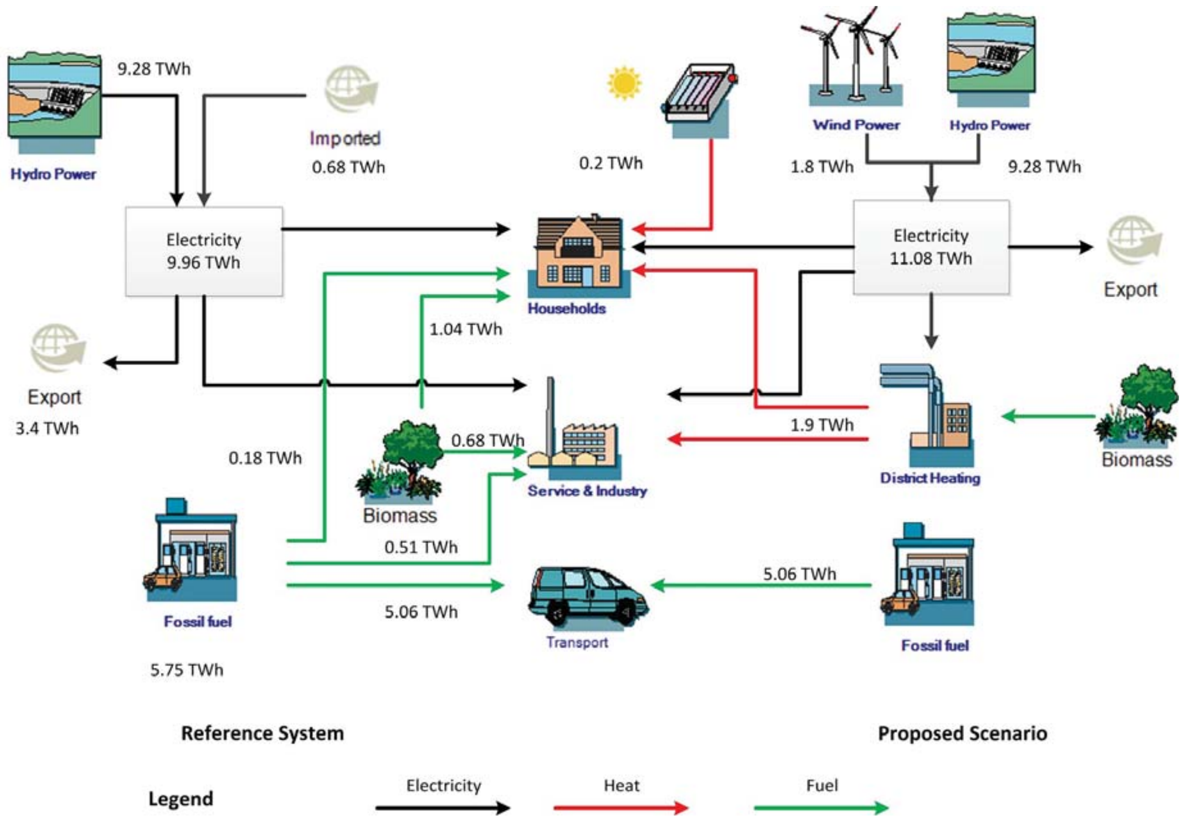

Figure 6: Inland reference and alternative system energy flow diagram (pictures are credited to ifu Hamburg GmbH)

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.

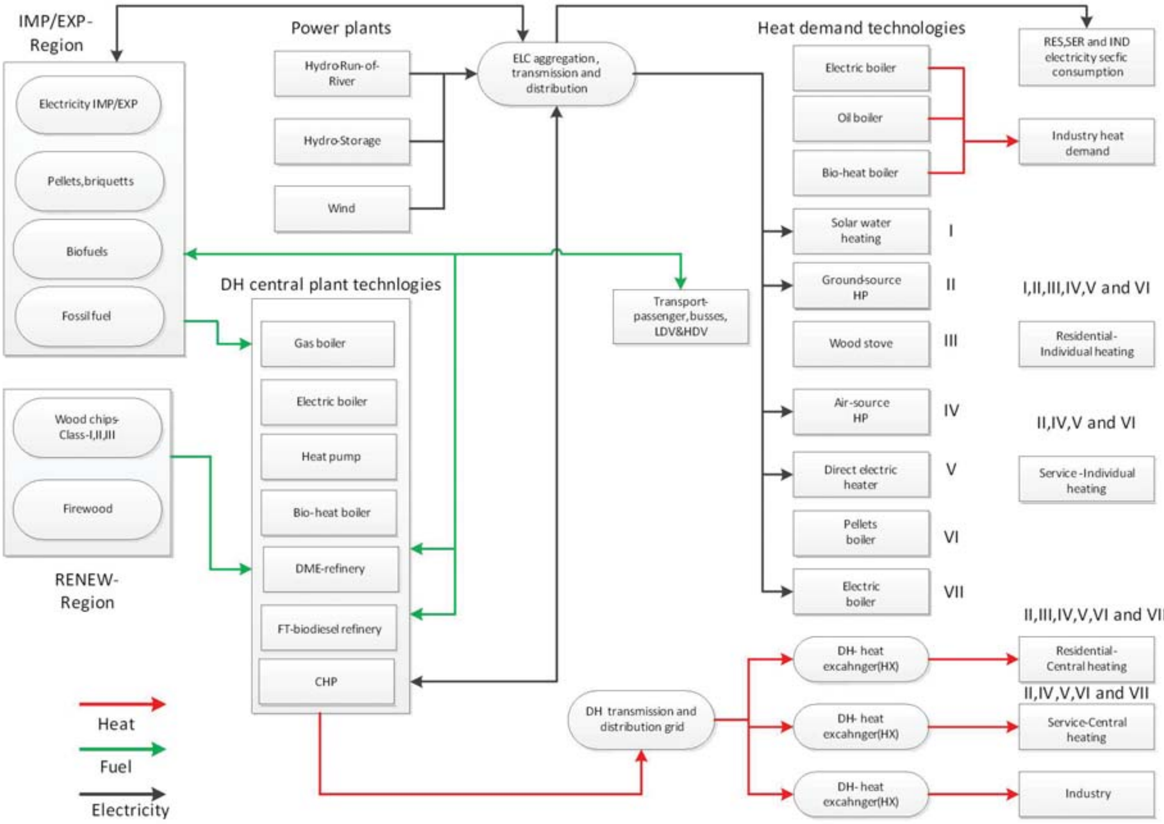

Figure 7: Model structure and energy flow diagram.

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.

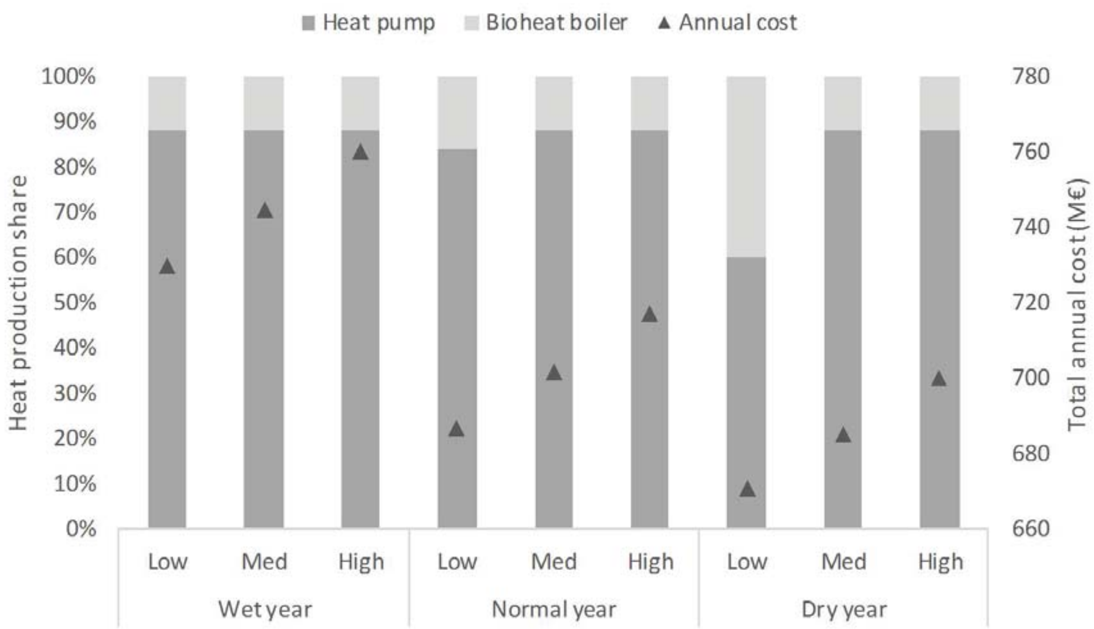

Figure 8: Total annual cost and DH (0.5 TWh) heat production share built on heat pumps and bioheat boilers for various electricity and biomass price levels. The lower annual cost (system cost), for the dry year case, is due to the high electricity price and hence increased revenue from electricity trade, 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.

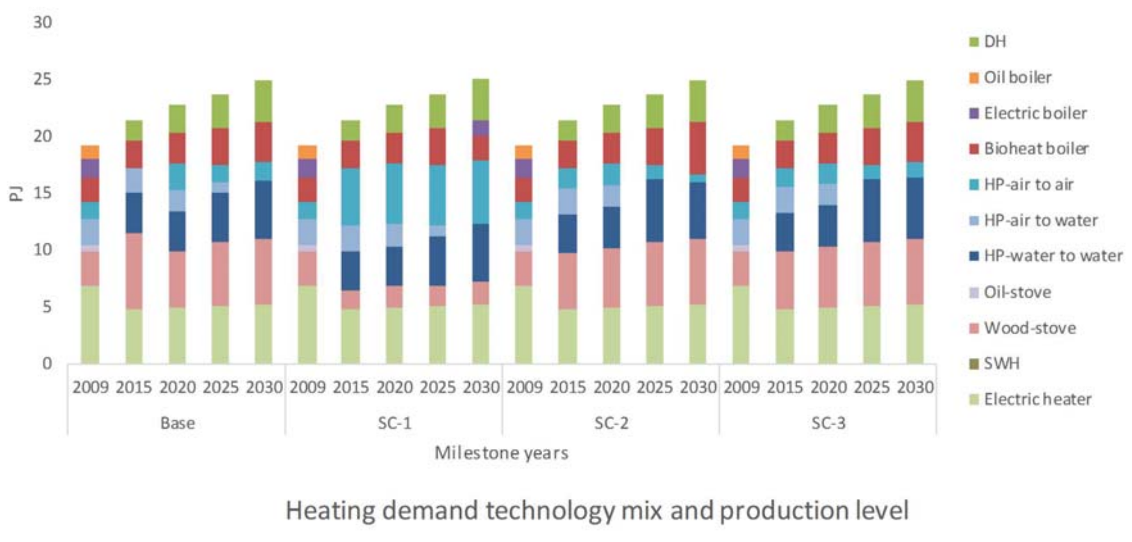

Figure 9: Heating demand technology mix and production levels of the whole energy system as it evolves towards 2030. The technology mix is an aggregate representation of the residential, service, and industri sectors. The results are taken from Paper IV.

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.

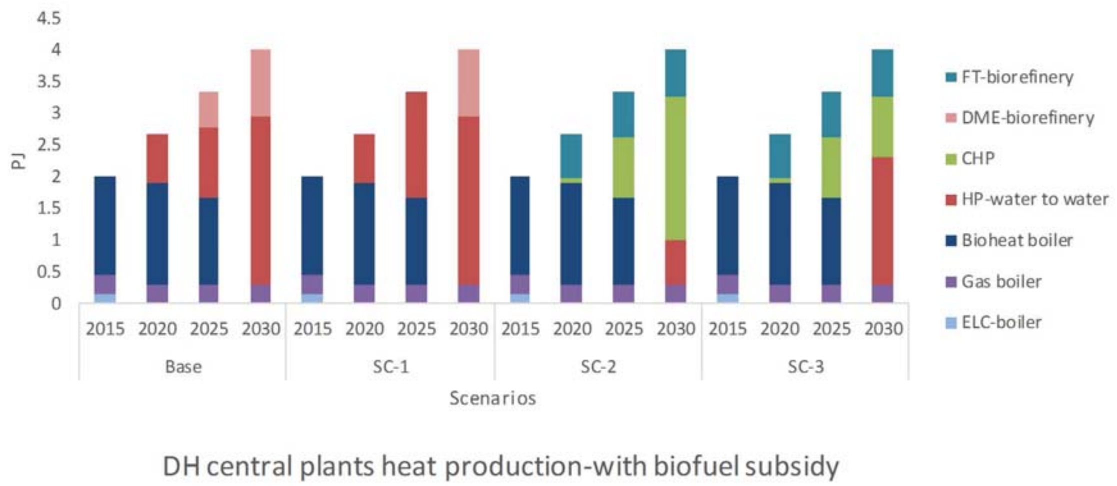

Figure 10: DH central plants composition and production mix evolvement towards 2030 when the minimum required biofuel subsidy for biorefinery technolgies is included. The results are taken from Paper IV.

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,

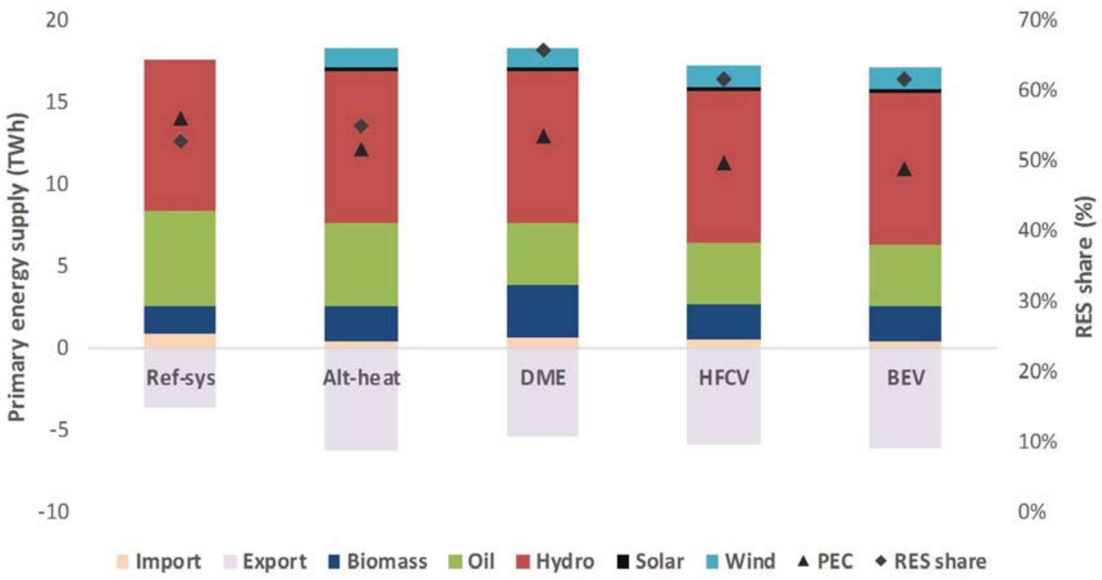

Figure 11: Primary energy consumption (PEC) and RES share of the reference and alternative systems in a normal year. Primary energy supply (PES) refers to domestic production while PEC is domestic production corrected for import and export. DME refers to an alternative transport system based on dimethyl 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.

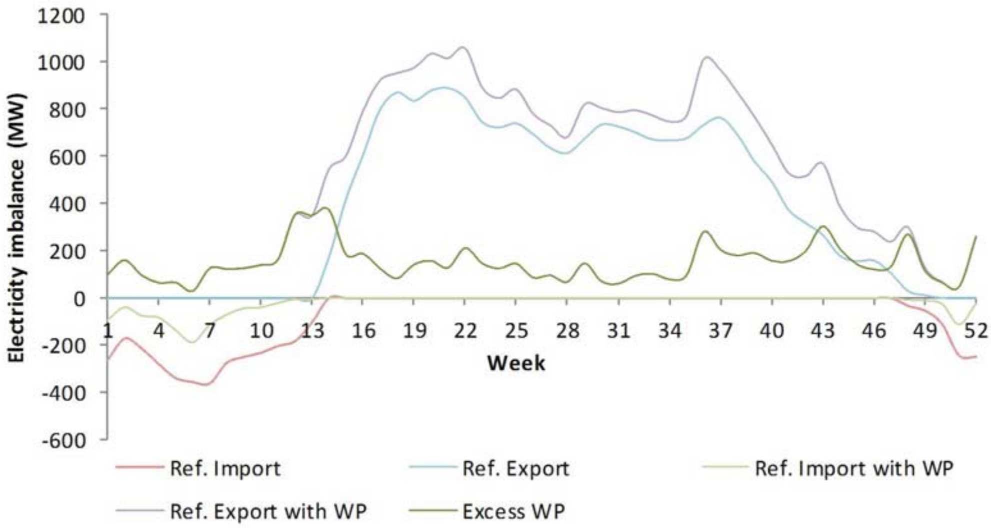

Figure 12: Weekly electricity imbalance of the reference system with and without 700 MW/1.8 TWh wind power (WP). Weeks 13-46 are high production time-summer, while 47-12 are high demand time-winter season. The results are taken from Paper II.

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.

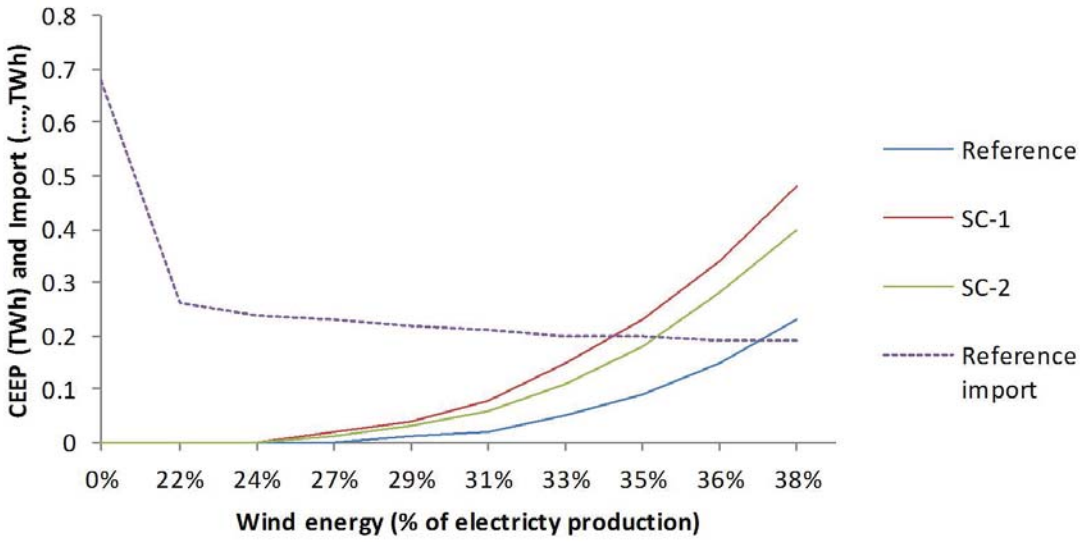

Figure 13: Critical excess electricity production (CEEP) and Import electricity for increasing wind energy penetration level in the reference system (Reference) and alternative energy systems (SC-1 and SC-2). The results are taken from Paper II.

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.

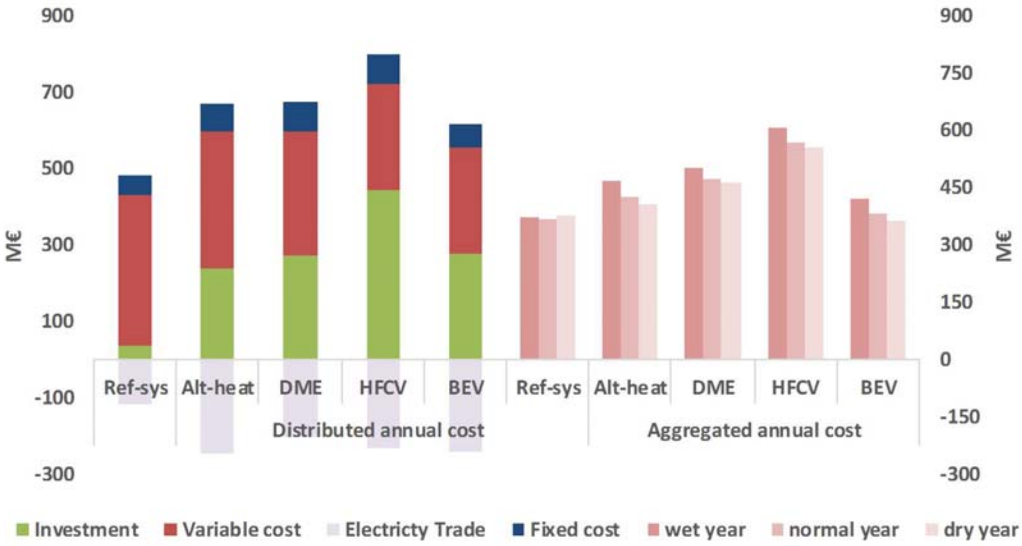

Figure 14: Detailed business-economic annual costs and aggregated annual costs of the reference and alternative systems in a normal year. The results are taken from Paper III.

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.

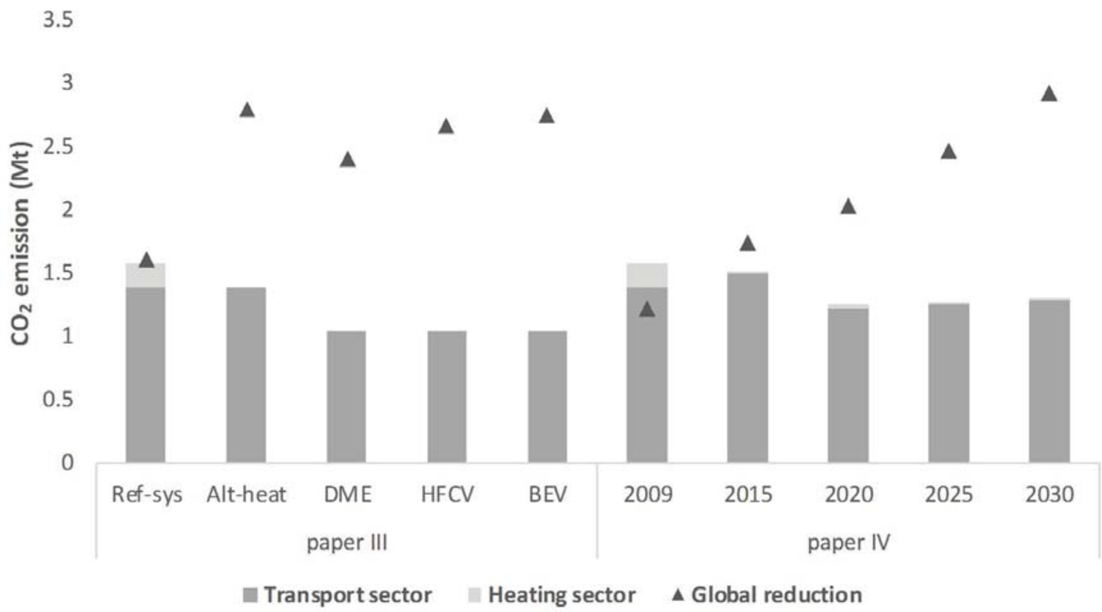

Figure 15: CO_2 emission levels of the reference and alternative system scenarios. The global emission reduction is due to the exportable green electricity assumed to replace condening power plants with an emission factor of 450 g/kWh. The results are taken from Paper III and IV.

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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