Impacts of Energy Sector Integration on Power System Operation

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Abstract

Electrification of energy intensive sectors is one of the main tools in decreasing fossil fuel consumption and lowering emissions as the carbon intensity of electricity generation is decreasing with increased penetration of renewables in the power system. However, the change does not come without challenges as simultaneously the share of flexible power generation is declining. The flexibility required by the power system has to be sought to an increasing extent from new resources, including the demand side. Sector integration is seen as a key solution in enabling the necessary flexibility to the power system as new technologies and energy carriers could be utilised to manage fluctuations in the power system.

In this thesis, power market modelling is used to illustrate and analyse the behaviour of sector integration technologies in 2035 with significantly increased electricity demand and renewable generation capacities. The focus is on technologies used in district heating and hydrogen production, namely heat pumps, electric boilers, and electrolysers. In the literature review, operation of the technologies is analysed based on existing installations and findings from pilot projects. The findings are used to discuss the potential drawbacks of current modelling methods for relevant technologies. Five modelling cases for district heating electrification and two modelling cases for hydrogen production are made to compare and analyse the impacts with different development paths of sector integration. Additionally, new demand profiles are developed for district heating heat pumps and electric boilers to better reflect their operation.

The market modelling demonstrated that higher flexibility for sector integration technologies leads to higher demand changes between market hours. Higher hourly changes means that the technologies can aid the system by reacting to changes in renewable generation and electricity prices with a higher degree. However, higher flexibility may also lead to higher magnitude errors in demand forecasts used in system operation which can have significant impacts on system operation activities.

Keywords sector integration, heat pumps, electric boilers, electrolysers, power market modelling, power balance management

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Tiivistelmä

Energiaintensiivisten alojen sähköistäminen on yksi tärkeimmistä työkaluista fossiilisten polttoaineiden kulutuksen ja päästöjen vähentämisessä, kun sähköntuotannon hiili-intensiteetti pienentyy uusiutuvien energialähteiden lisääntyessä sähköjärjestelmässä. Muutos ei kuitenkaan tule ilman haasteita, kun yhtäaikaisesti säädettävän sähköntuotannon osuus laskee. Sähköjärjestelmän edellyttämää joustavuutta on haettava entistä enemmän uusista resursseista, myös kysyntäpuolelta. Sektori-integraatio nähdään keskeisenä ratkaisuna mahdollistamaan sähköjärjestelmään tarvittava joustavuus, sillä se sallii uusien teknologioiden ja energiamuotojen hyödyntämisen sähköjärjestelmän vaihteluiden hallinnassa.

Työssä havainnollistetaan ja analysoidaan sektori-integraatioteknologioiden käyttäytymistä sähköjärjestelmässä sähkömarkkinamallinnuksen avulla. Mallinnusvuotena on 2035, jolloin sähkön kysynnän sekä uusiutuvien tuotantokapasiteetin ennustetaan merkittävästi kasvaneen. Tarkasteltavana ovat kaukolämmön ja vedyn tuotannon sähköistymisessä käytettävät teknologiat, erityisesti lämpöpumput, sähkökattilat ja elektrolyyserit. Kirjallisuuskatsauksessa teknologioiden käyttöä analysoidaan olemassa olevien laitteistojen ja pilottiprojektien avulla. Löydöksiä käytetään nykyisten mallinnusmenetelmien mahdollisten kehityskohteiden analysointiin. Mallinnuksessa analysoitiin sektori-integraation eri kehityspolkuja vertailemalla ja analysoimalla viittä eri tapausta kaukolämmön sähköistymisestä sekä kahta tapausta vedyn tuotannosta. Lisäksi kaukolämpöpumpuille ja sähkökattiloille kehitettiin uudet kysyntäprofiilit, jotka kuvastavat paremmin niiden tavanomaista käyttöä.

Markkinamallinnus osoitti, että sektori-integraatioteknologioiden suurempi joustavuus johtaa suurempiin kysynnän muutoksiin markkinatuntien välillä. Suuremmat tuntimuutokset tarkoittavat, että teknologiat voivat auttaa järjestelmää tehokkaammin reagoimalla uusiutuvan tuotannon ja sähkön hintojen muutoksiin voimakkaammin. Suurempi joustavuus voi kuitenkin johtaa myös suurempiin virheisiin sähköjärjestelmän hallinnassa käytettävissä kysyntäennusteissa, millä voi olla merkittäviä vaikutuksia järjestelmän käyttötoimintaan.

Avainsanat sektori-integraatio, lämpöpumput, sähkökattilat, elektrolyyserit, sähkömarkkinamallinnus, tehotasapainonhallinta

Contents

Preface

This thesis was written at the Market Solutions unit of Fingrid Oyj. I want to thank my advisors Lic.Sc Jussi Matilainen and M.Sc. Niko Korhonen from Fingrid Oyj for the guidance throughout the writing process. Many thanks also to Risto Kuusi and Jussi Närhi from the strategic grid planning unit, as well as to all the members of the thesis steering group, for your guidance and great discussions during the thesis. I would also like to express my gratitude to Professor Sanna Syri from Aalto University for supervising the thesis.

Finally, I would like to thank my family and friends for all the support and good times during my student years. Thank you, Amanda, for supporting and pushing me to the finish line.

Helsinki 25.4.2022

Mikko Hyvölä

Abbreviations

AEL	Alkaline
AEM	Anion Exchange Membrane
aFRR	Automatic Frequency Restoration Reserve
BRP	Balance Responsible Party
BSP	Balance Service Provider
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
DH	District Heating
DSO	Distribution System Operator
EB	Electric Boiler
EC	European Commission
EV	Electric Vehicle
EU ETS	European Union Emission Trading Scheme
FCR	Frequency Containment Reserve
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operation
HHV	Higher Heating Value
HP	Heat Pump
LHV	Lower Heating Value
mFRR	Manual Frequency Restoration Reserve
MW	Megawatt
PEM	Proton Exchange Membrane
PII	Power Intensive Industry
RED	Renewable Energy Directive
SMR	Steam Methane Reforming
SO	System Operator
SOEC	Solid Oxide Electrolyser Cell
TSO	Transmission System Operator
TWh	Terawatt-hour
VRE	Variable Renewable Energy

1 Introduction

1.1 Background

The Finnish government has set a goal in its programme to achieve carbon neutrality by 2035 (Finnish Government 2019). Furthermore, the European Commission (EC) published the Fit for 55 -package in July 2021 with which it aims to steer the European Union towards climate neutrality by 2050. The aim is to reduce greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels (European Commission, 2021a). The targets call for a significant reduction in greenhouse gas emissions, in which energy production and consumption will play a significant role. The decline in emissions from energy production indirectly lowers emissions from other industries as emissions from their purchased energy fall.

Electrification of energy consuming sectors is seen as one of the primary tools to lower their emissions. In 2019, 82% of electricity production in Finland was carbon neutral and the share of variable renewable energy (VRE), such as wind power, is growing rapidly. Electricity use in heating, transportation and industry is forecasted to increase significantly during the following decades. For example, in Finland, electrification could double the use of electricity in industry and grow the total electricity consumption of Finland by 50% by the year 2050. (Paloneva & Takamäki, 2021; Official Statistics of Finland (OSF), 2022a)

The growing share of variable renewables in the Finnish power system also poses some challenges as simultaneously the share of flexible production, such as condensing power plants, is declining. There is a growing need to respond to power fluctuations also on the demand side. The flexibility required by the power system has to be sought to an increasing extent from new sources.

Sector integration is seen as an important solution to enable the necessary flexibility to the power system. Sector integration refers to the integration of different energy sectors into a mutually supportive system, where the sectors can balance each other's production and consumption peaks. With the help of sector integration, the energy system can utilize resources more efficiently and where needed (European Commission, 2020b). Electricity consumption is expected to increase significantly in the coming years due to emission reduction targets and new technological solutions.

In addition to the increase in electricity consumption new challenges can be caused by, for example, the behaviour of new consumption technologies,

their location or the difficulty of forecasting the demand. The peak power demand can also increase drastically if new electricity consuming technologies do not provide any flexibility to the system. As flexible generation decreases in the market, problems may also arise in system operation if the transmission system operator (TSO) does not have sufficient controllable resources at its disposal. On the other hand, new electricity consuming technologies can provide additional resources and flexibility to the needs of the TSO if those characteristics are considered when integrated into the power system.

1.2 Scope and limitations

The thesis assesses sector integration from the point of view of a transmission system operator. The thesis aims to create an image of how the electrification of different energy sectors currently affects the power system and what can be the future impacts with different development pathways of sector integration. In addition, the thesis aims to create a picture of the current status of sector integration and discusses the foreseen development of electricity consumption in different sectors, including their flexibility potential, for the year 2035. Based on the findings, the thesis aims to develop modelling methods of sector integration technologies to study the benefits and challenges of sector integration more accurately on power system operation in the future. In this thesis, the results from power market modelling are analysed by a quantification method that focuses on analysing the changes in electricity generation and demand between market hours. The focus is therefore in analysing hourly power changes and their impacts on system operation, mainly from the power balance management perspective.

The thesis focuses on large-scale electrification of energy-intensive industries, more specifically the electrification of district heating and industrial process heating, and the production of hydrogen by water electrolysis.

1.3 Author contributions

The quantification methods and tools for analysing power market simulation data is developed by Visa Simola in his thesis “Quantification Methods for the Demand and Value of Flexibility” that was written at the same time as the author’s thesis. The strategic grid planning unit of Fingrid has developed the initial parametrization and development estimates for the utilized scenarios. They also helped greatly in learning how to use the market modelling software.

2 Sector integration in the Finnish power system

This chapter provides an overview of the Finnish power system as well as the status of sector integration in district heating and process heating. In addition, the current state of hydrogen production and use globally and in Finland is discussed. The chapter also reviews current energy production technologies and their electricity use in energy-intensive sectors. Finally, regulatory changes affecting sector integration development in relevant sectors are discussed.

2.1 Current power system

The electricity production in Finland is covered largely by carbon-neutral sources. Figure 1 shows the methods of electricity production in Finland in 2020, including net imports. 85% of electricity produced in Finland came from carbon-neutral sources, the main sources being nuclear power, hydropower, biomass, and wind power. In total 66 terawatt-hours (TWh) of electricity were produced in Finland in 2020. Electricity consumption in Finland in 2020 was 81 TWh. The share of wind and nuclear power in Finnish electricity production is on track to grow significantly during the following years. The Finnish TSO Fingrid has received project inquiries for 70 000 megawatts (MW) worth of wind power. Even if a low percentage of these projects realize, the growth of wind power capacity is significant. The installed wind power capacity in Finland was 2585 MW at the end of 2020. Olkiluoto 3 will bring a significant increase to nuclear power generation capacity once it starts production. In February 2022, steady commercial production is estimated to begin in July 2022 (Pesonen-Smith, 2022). The plant has a production capacity of 1600 MW. Finnish nuclear power capacity is currently 2800 MW. (OSF, 2022a; Laatikainen, 2020; Energiateollisuus, 2021b)

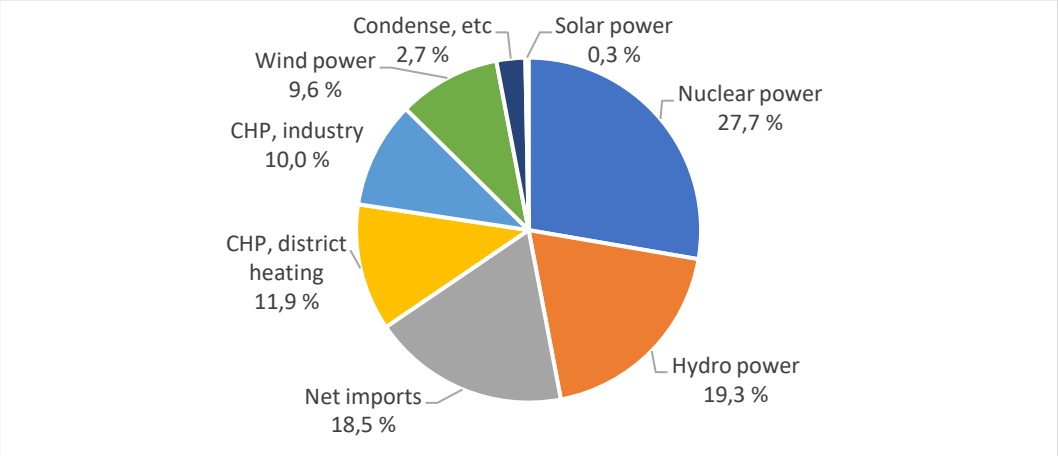


Figure 1: Electricity consumed in Finland in 2020 by production type (OSF, 2022a)

Finland is connected to all of its neighbouring countries – Sweden, Norway, Russia and Estonia - by high-voltage lines. The largest share of the imports typically come from Nordic countries, but Russia has also been a significant source of electricity imports. Electricity is mainly exported to Estonia (Energiateollisuus, 2021b). There is a lot of electricity-intensive industry in Finland. In total, industries used 46% of all consumed electricity in the year 2020. Figure 2 shows the electricity consumed in the year 2020 by different sectors.

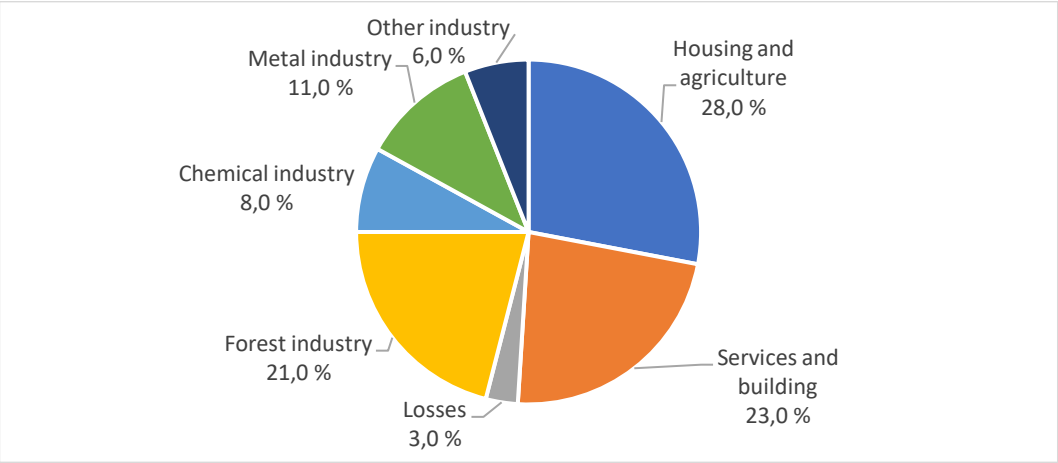


Figure 2: Electricity consumed in Finland in 2020 by sector (OSF, 2022a)

2.2 Electricity use in energy sectors

In 2020, the final energy consumption was 288 TWh in Finland. Therefore, roughly 28% of the final energy demand in Finland was covered by electricity. This chapter discusses how much electricity was used in district heating and industry sectors in 2019. Detailed statistics from 2020 were not available when data was collected for the thesis.

2.2.1 District heating

District heating (DH) is the most common heating form in Finland. In 2020, 54% of Finnish citizens used district heating (Energiateollisuus, 2021b). With district heating networks many heat plants and resources can be connected to a large amount of heat demand. The heat demand that varies highly based on temperature can then be covered by the cheapest heat production methods in the DH network. New production methods, such as using heat pumps (HP) to utilise waste heat, are becoming more common (Energiateollisuus 2021a). Figure 3 presents the total district heating production in Finland in 2019 and the amount of heat produced by different energy sources. In 2019, 50% of district heating was produced with fossil

fuels, including peat, which is equivalent to roughly 19 terawatt-hours of heat. The heat from heat recovery and heat pumps covered about 10% of total district heat production. In 2018 this portion was 9%. Of this nine per cent, 6% was covered by heat recovery, more specifically by flue gas scrubbers, and 3% was covered by heat pumps (AFRY, 2021). In 2019, 547 GWh of electricity was used in heat pumps and electric boilers (EB) in district heating networks (Energiateollisuus, 2021b).

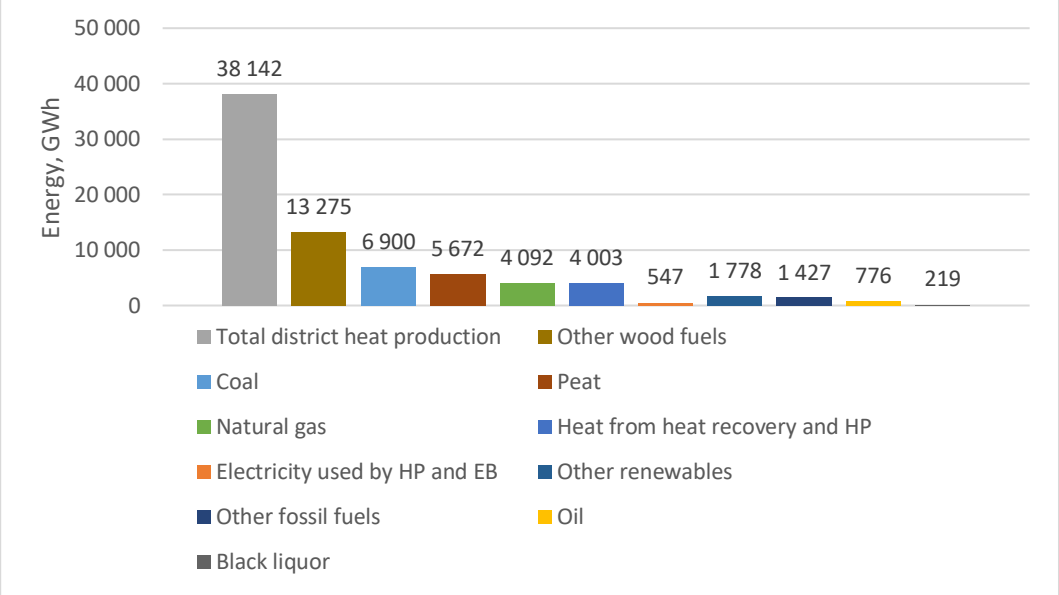


Figure 3: Heat production by energy source in district heating in 2019 (OSF, 2022b; Energiateollisuus, 2021b)

In Finland, district heating production is mainly based on combined heat and power production (CHP) and the use of heat only boilers (HOB). As presented in Figure 3, district heat production currently relies heavily on the use fossil fuels, especially in larger cities with high heat demand and more difficult access to large quantities of biomass. Due to the decarbonisation target of Finland, the targets of individual companies and cities, and the rising costs of fossil-fuel based production, district heating companies are moving towards new technologies. As with industry and transport, electrification is seen as an effective way to reduce emissions in district heating. For example, the two largest district heating companies in Finland, Helen and Fortum, have goals to have carbon neutral district heating in 2030 and 2029 by the latest. Utilisation of waste-heat and heat pumps is a key element in achieving the goal for both companies, as is the use of biomass. Helen also emphasises the need for flexibility. The company operates large heat storages and is currently constructing and planning new ones (Fortum, 2021; Helen, 2021).

District heating is considered to be a good complement to variable renewables as they can utilise hours with high VRE production and low electricity prices to generate heat with heat pumps and electric boilers while potentially avoiding the need to curtail renewable production. During low VRE production and high electricity prices, CHP can be used instead of heat pumps and electric boilers (EB) to generate both heat and electricity. Electrification of DH could provide flexibility to the electricity system as DH networks typically have alternative resources to be used to cover heating needs if electricity demand needs to be cut down momentarily. The other benefit of electrification in district heating is that the DH network itself can act as storage for heat. The flexibility potential of DH networks can be further increased with the use of heat storages. With heat storages, heat generation can be decoupled from heat demand. This allows for optimising heat generation to the lowest-cost hours, which for HPs and EBs are the low electricity price hours. For CHP plants, which make profit from electricity sales, the lowest-cost hours for heat production are during high electricity prices. (Paiho & Reda, 2016)

In the Finnish Energy low-carbon roadmap, the use of waste heat is expected to cover 11 TWh in the business-as-usual scenario and 8 TWh in the low-carbon scenario of DH needs in Finland in 2035. Additionally, both scenarios assume 4 TWh of DH needs to be covered by geothermal heat. This translates to 3 and 2 TWh of electricity use in DH in the scenarios. The lower utilisation of waste heat in the low-carbon scenario is due to higher electricity prices which makes the use of electricity in DH less competitive and increases the share of CHP in relation to the business-as-usual scenario (AFRY, 2020). As stated by Helin, Syri, and Zakeri (2018), the large increase in HP capacity in DH networks may have an impact on the entire electricity market. Because of the electricity market's use of marginal pricing, the price of power theoretically rises with each extra megawatt-hour of demand. In order to understand the system level impacts of utilisation of heat pumps in DH networks, district heating production needs to be modelled along with the electricity market.

2.2.2 Energy used in industry

As presented in Figure 2, the largest industrial consumers of electricity are the forest, chemical and metal industries. These three industries are also the largest consumers of energy in Finland, the forest industry being the largest. It used almost 60% of the 147 TWh of energy used in industry in 2019. Figure 4 presents the energy consumption of industrial sectors and the share of electricity in it. It should be noted that a 100% share of electricity consumption, meaning direct electrification, in industrial energy use is not possible in all sectors as energy is used as feedstock in industrial processes in

some sectors. The share of electricity, presented by the blue columns in Figure 4, includes purchased electricity and electricity produced on-site in industrial facilities. In Finnish statistics, electricity used in heat pumps and electric boilers is included in the category "other energy sources". The category also includes other by-products and wastes used as fuel, exothermic heat from industry, secondary heat from industry and purchased steam (OSF, 2020a). Electricity consumption of heat pumps and electric boilers in industry is therefore not included in the blue column. Electricity covers 21% of primary energy use in all industries combined. However, if we consider the end-use of energy, electricity covers 27% as a portion of primary energy is used for electricity production. The energy intensive industries are all among the least electrified with all of them using under 35% of their energy as electricity. A significant amount of electricity is produced on-site in industrial facilities, especially in the forest industry. The difference between purchased electricity and consumed electricity is roughly 7,5 TWh in the forest industry. (OSF, 2022a)

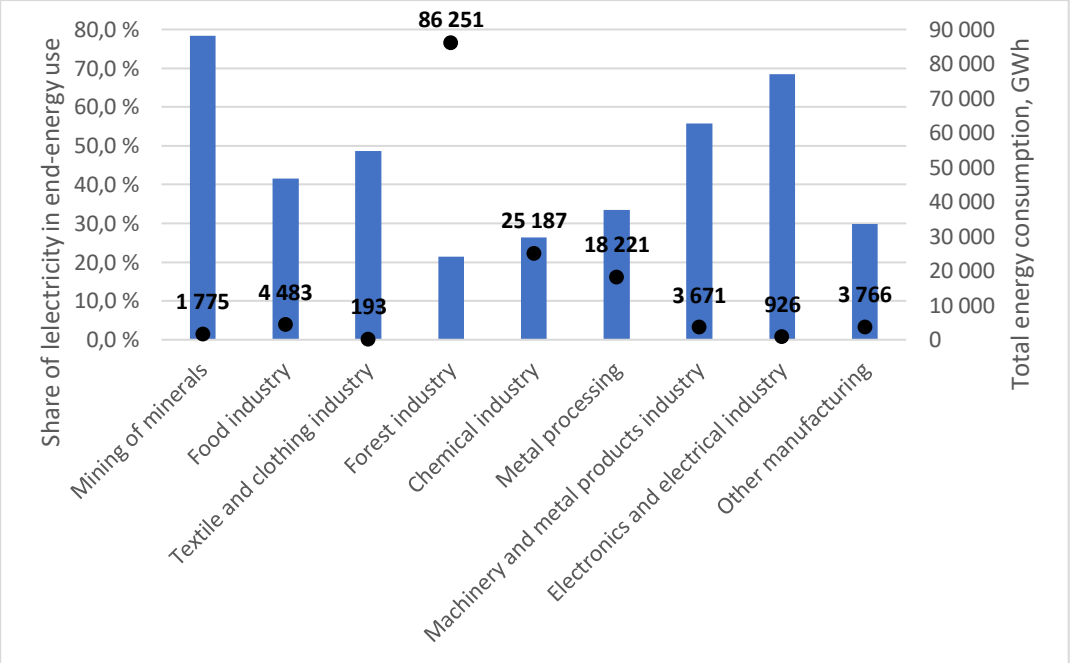


Figure 4: Total energy use (black dots) and share of electricity of end-energy use (blue column) per industry sector in Finland in 2019 (OSF, 2022a)

Industrial heat production in Finland is largely covered by the use of waste streams of forest industry and biomass, as presented in Figure 5. In 2019, 19% of industrial heat was produced with fossil fuels, including peat, which is equivalent to roughly 10 terawatt hours of heat. When compared to district heating, the share of carbon-neutral heat production in industry is much higher than in district heating. This is due to the fact that a large part of energy consumption comes from the forest industry, where cheap biomass-

based energy sources for heating are available on site. Electricity use of electric boilers and heat pumps in industrial heating is included in "other energy sources" in the statistics, which shows that electricity use for process heating plays a minor role in Finland. In the chemical, forest and metal industries, part of the use of heat is taken into account in the statistics as direct fuel use and is therefore not included in the industrial heat production figures (OSF, 2020b).

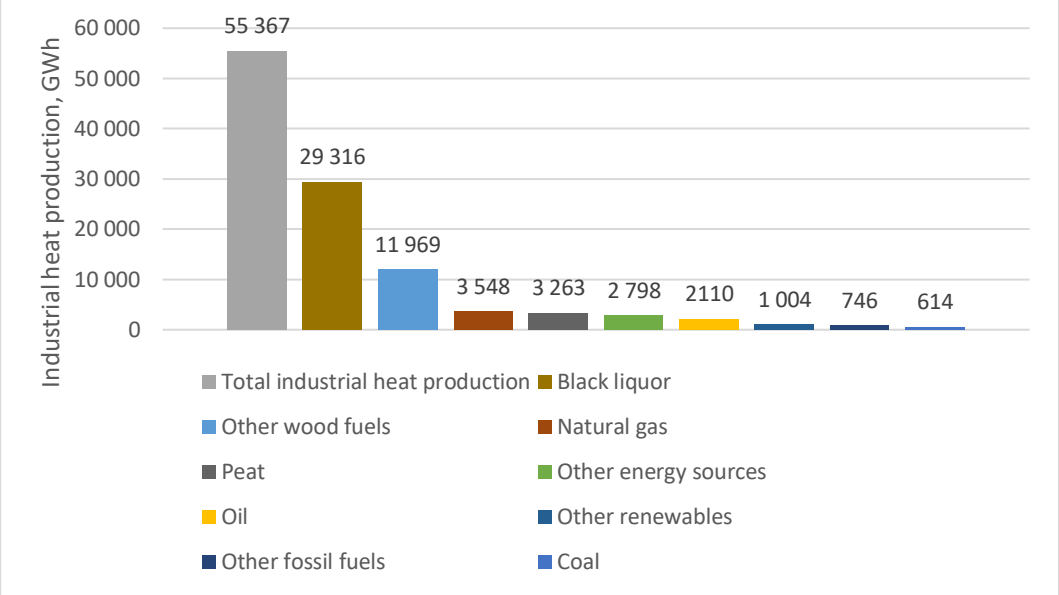


Figure 5: Finnish industrial heat production by energy source in 2019 (OSF, 2022b)

2.2.3 Production and use of hydrogen

Hydrogen is used largely by industries as feedstock to produce chemical products. Figure 6 presents the energy sources for global hydrogen production and its end uses. Today, the dedicated production of hydrogen is based heavily on fossil fuels. Globally, 6% of natural gas and 2% of coal use stems from the production of hydrogen, resulting in 76% and 23% of dedicated hydrogen production. Water electrolysis currently accounts for less than 0,1% of global dedicated hydrogen production. Water electrolysers are electrochemical devices that split water molecules into hydrogen and oxygen with an electrical current. As a result, the production of hydrogen accounts for approximately 830 million tonnes of CO2 emissions per year. As actions need to be taken to mitigate climate change and the emission reduction targets are tightening, hydrogen - especially hydrogen produced with renewable energy - has recently received growing attention due to its potential to reduce carbon emissions. By producing hydrogen in low- or zero-carbon methods, and by using it to replace hydrogen with a higher carbon footprint, emissions in large industrial sectors can be decreased. Hydrogen can also serve as an energy carrier, as well as an energy storage medium in

the energy system, helping to alleviate imbalances in variable power generation. (IEA, 2019; Laurikko et al., 2020)

Steam methane reforming (SMR) from natural gas is the most common technology for hydrogen production. Autothermal reforming is also used. Hydrogen produced from natural gas with SMR is commonly referred to as grey hydrogen. If carbon capture and storage (CCS) is implemented in the SMR process, up to 90% of CO2 emissions can be captured. Hydrogen produced from natural gas with CCS is commonly referred to as blue hydrogen, which can be a low-carbon alternative to current grey hydrogen. In Finland, the production of blue hydrogen is more difficult because the country does not possess great opportunities for the permanent storage of carbon dioxide. Nonetheless, blue hydrogen can be important in Finland for quickly achieving considerable reductions in emissions from existing hydrogen production throughout the transition period to large-scale renewable generation (Hydrogen Cluster Finland, 2021). A zero-carbon alternative is hydrogen produced with water electrolysis utilising renewable electricity, which is commonly referred to as green hydrogen (IEA, 2019; IRENA, 2020). This thesis focuses on the production of hydrogen with water electrolysis, as it most significantly impacts the demand of electricity.

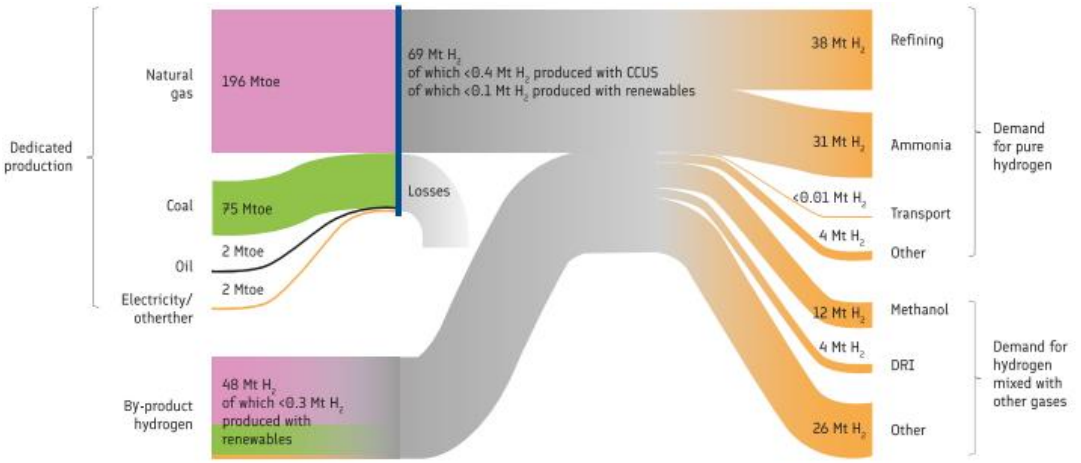


Figure 6: Global production and use of hydrogen (IEA, 2019; Laurikko et al., 2020)

In Finland, total dedicated hydrogen production is estimated to be 140 000–150 000 tonnes per year, equivalent to 4,7 – 5,0 TWh of energy, of which 99% is produced through steam reforming or partial oxidation of fossil fuels and 1% is produced through water electrolysis. In addition, 0,73 – 0,8 TWh of by-product hydrogen is generated during sodium chloride (NaCl) electrolysis. One kilogram of hydrogen is equivalent to 33,3 kilowatt hours of energy when the energy content is measured in lower heating value (LHV). LHV value depicts the energy content of the fuel in a case where the energy content of

vaporised steam is not recovered during combustion. In a case where the water of combustion is entirely condensed and the energy contained in the water vapor is recovered, the energy content is higher. The higher heating value (HHV) energy content for hydrogen is 39,4 kilowatt hours per kilogram (Engineering Toolbox, 2003). Figure 7 presents the current production methods and use of hydrogen in Finland. Almost 90% of dedicated hydrogen production today is used in oil refining and biofuel production. Currently, only a few hundred tonnes of hydrogen are utilised in the steel industry to avoid steel oxidation. The current locations of dedicated hydrogen production and consumption are largely in south to south-eastern Finland, but the planned production sites for future wind power are mostly in the north. The electrification of current hydrogen production can therefore lead to large increases in required north-to-south electricity transmission capacity, if hydrogen is produced on-site at the demand centers. (Laurikko et al., 2020)

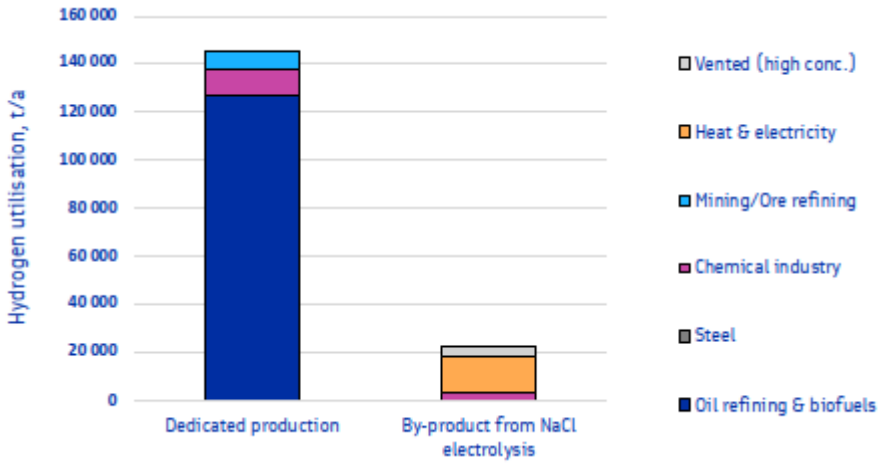


Figure 7: Current production methods and use of hydrogen in Finland (Laurikko et al., 2020)

In addition to decreasing the emissions of current hydrogen use, low- and zero-carbon hydrogen can be used in new applications as an alternative to current fuels and feedstocks, in areas where direct electrification is not suitable, for example in steel production, aviation and shipping. Hydrogen can be used as is or it can be further refined to hydrogen-based products such as synthetic methane or liquid fuels like ammonia or methanol. These power-to-gas or power-to-liquid pathways are often collectively referred to as power-to-X. Figure 8 shows the most prominent uses of green hydrogen and derived products when other emission mitigating measures, such as direct electrification, have also been considered. On the power sector, hydrogen is seen as a long-term storage solution for variable renewables. Hydrogen can also be used to transport energy over long distances from regions with good

VRE production capabilities. (Agora Energiewende & Guidehouse, 2021; Laurikko et al., 2020)

Green molecules needed?	Industry	Transport	Power sector	Buildings
Uncontroversial	· Reaction agents (DRI steel) · Feedstock (ammonia, chemicals)	· Long-haul aviation · Maritime shipping	· Long-term storage for variable renewable energy back-up	· District heating (residual heat load *)
Controversial	· High-temperature heat	· Trucks and buses ** · Short-haul aviation and shipping	· Absolute size of need given other flexibility and storage options	
Bad idea	· Low-temperature heat	· Cars · Light-duty vehicles		Individual buildings

* After using renewable energy, ambient and waste heat as much as possible. Especially relevant for large existing district heating systems with high flow temperatures. Note that according to the UNFCCC Common Reporting Format, district heating is classified as being part of the power sector.

** Series production currently more advanced on electric than on hydrogen for heavy duty vehicles and busses. Hydrogen heavy duty to be deployed at this point in time only in locations with synergies (ports, industry clusters).

Figure 8: Most prominent uses of green hydrogen and derived products (Agora Energiewende & Guidehouse, 2021)

Figure 9 depicts the power-to-X concept and how it can allow the integration of electricity, heat, and gas systems. Sector integration can increase the economic viability of power-to-X technologies by selling conversion by-products such as heat to district heating networks or process businesses. Additional revenue streams can be generated by selling oxygen or hydrocarbons. Power-to-X technologies, on the other hand, may cut total system costs, for example, by providing demand side flexibility to the power system through flexible operation of electrolysers. (Munster et al., 2020)

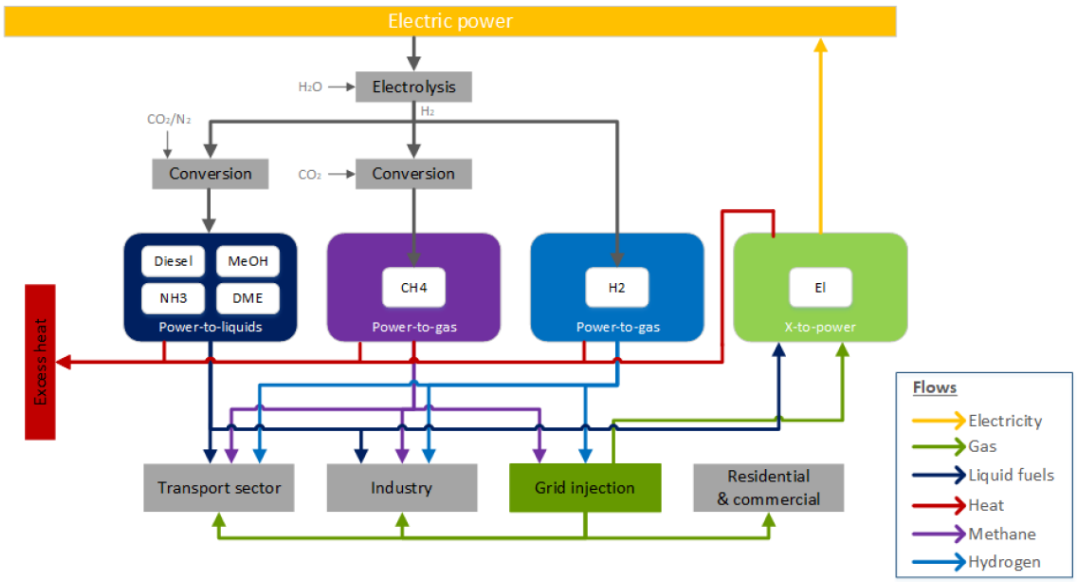


Figure 9: The concept of power-to-X and illustration of integration of energy sectors (Munster et al., 2020)

2.3 Regulatory changes concerning sector integration

The driving force behind sector integration is the goal to reduce greenhouse gas emissions. Electrification is seen as the most suitable tool to reduce emissions in many sectors. The electricity production sector itself is becoming greener as the carbon intensity of produced electricity decreases with a growing share of carbon-free sources such as wind and solar power. This chapter aims to give an overview of the most visible and discussed legislation proposals that can have significant impacts on which path the development of sector integration continues and at what pace. The Fit for 55 -package published by the European Commission includes directive proposals that can have great influences on the developments in the energy sector. The legislation process is still on-going. The Fit for 55 -package and the on-going regulatory work supporting it includes various aspects affecting sector integration and electrification of different energy sectors. Not all influencing factors have certainly been opened up in this chapter, but it is important to understand the role of legislation when considering developments in the energy sector, especially as new technologies are becoming more widespread.

In the EU, the main tool to incentivise decreasing greenhouse gas emissions is the EU Emissions Trading System (ETS). The EU ETS is a cap-and-trade system, that sets a cap on the total amount of greenhouse gas emitted by the installations in the system. The EU ETS scheme covers 40% of EU's greenhouse gas emissions by covering electricity and heat generation and energy intensive industry sectors. Installations covered by the system have to buy or receive emissions allowances that cover their yearly emissions. Emission allowances must be handed out after each year and if the emissions exceed the amount of bought or received allowances the installation is heavily fined. The possibility of freely trading the emission allowances between market participants leads to a system where greenhouse gas emissions will be decreased where it is most cost-efficient. As the number of allowances is limited, a value for emissions is set through the trade of emission allowances. This value encourages investments in low-carbon technologies. (European Commission, 2017)

In the Fit for 55 -package published on July 2021, the European Commission proposed major changes to the EU ETS. Previously, the emissions reduction target from 1990 levels in the EU was 40%, but as mentioned before, it is tightened to 55% in the new proposal. To reach this tightened goal, the European Commission proposed to lower the emission cap in the EU ETS and increase the reduction rate for emission allowances. Furthermore, free emission allowances for aviation are proposed to be phased out and aligned with the global emission trading scheme for aviation, CORSIA (Carbon

Offsetting and Reduction Scheme for International Aviation). EC also proposed to include maritime shipping emissions in the EU ETS. If the proposed actions will realise, the total amount of emission allowances in the market will decrease significantly, while simultaneously there will be new demand from new sectors with high emission reduction costs, which will most likely lead to increased price of EU ETS allowances and a higher incentive to invest in emission reductions. (European Commission, 2021a)

Furthermore, to guide investments towards sustainable projects and activities, the EU has developed a common classification system for sustainable economic activities called the EU taxonomy. It is visioned to play a significant role in assisting the EU in scaling up sustainable investment and implementing the European Green Deal. The EU taxonomy would provide proper definitions for which economic activities can be considered environmentally sustainable to enterprises, investors, and regulators. (European Commission, 2020c)

One major regulatory proposal also published in the Fit for 55 -package is the carbon border adjustment mechanism (CBAM). The mechanism would require importers of cement, iron and steel, aluminium, fertilisers, and electricity to buy CBAM certificates in order to import their goods into the EU. The price of CBAM certificates is planned to be based on the weekly average auction price of the EU ETS allowances. If the importer can prove that they have already paid a price for carbon for the produced goods, the amount will be deducted from their bill. The regulation in essence sets a price for carbon for energy intensive imported goods and by placing the regulation the European Commission is trying to address the problem of potential carbon leakage and advocate investments in decarbonising energy intensive industries. The legislation is planned to be valid as of 2026. (European Commission, 2021c)

2.3.1 Regulatory changes promoting the growth of Power-to-Heat

District heating and large energy intensive industries are covered by the EU ETS, so the changes proposed directly affect the sectors as well. If emission allowance prices increase, the competitiveness of fossil-fuels in heating decreases. That will most likely lead to increased investments in heat pumps and electric boilers in both process and district heating.

The Finnish government made a regulatory decision in the fall of 2021 to lower the taxation level of electricity used by heat pumps and electric boilers in district heating networks. The taxation level of data centers providing their waste heat to district heating networks is also planned to be decreased. In addition, data centers that meet energy efficiency and energy use criteria and

operate outside DH networks are eligible for a lower electricity tax class, as are industrial-size property-specific heat pumps. Tax class II already includes industry, mining, professional greenhouse cultivation and data centers that are over 5 megawatts in size. Lowering the taxation level to class II lowers the electricity tax from 22,53 €/MWh to 0,63 €/MWh. This has a significant impact on the cost-competitiveness of heat pumps and electric boilers in district heating. The new taxation level is planned to be implemented in 2022. (Finnish Government, 2021; Ministry of Finance, 2021)

The government has also decided to introduce a support for electrification for energy intensive industries. In Finland, these are - as seen in Figure 4 - the forest, metal, and chemical industries. As stated by Ministry of Economic Affairs and Employment, the support will provide more effective incentives for carbon-neutral production, the electrification of energy-intensive companies and take into account cost competitiveness. The support would be fixed term for the years 2021–2025. The main idea behind the support is to compensate the increased cost of electricity caused by the EU ETS to large electricity consumers. The legislation for the support is still under work in 2022. (Ministry of Economic Affairs and Employment, 2021)

2.3.2 Regulatory development on Power-to-Hydrogen

On the EU level there are plans for significant push and pull regulatory mechanisms to increase supply and demand of renewable hydrogen. Renewable hydrogen, or green hydrogen, is hydrogen that is produced through water electrolysis utilising electricity from renewable energy sources, such as wind and solar power. In the hydrogen strategy published by the European Commission in July 2020, the EC is proposing a goal for renewable hydrogen electrolyser capacity. The proposed goal is 40 GW capacity installed by the year 2030 and 10 million tonnes of renewable hydrogen produced in the EU. By the year 2024, the goal is 6 GW. The EU currently uses around 9,7 MT of hydrogen annually (Hydrogen Roadmap Europe, 2019). However, demand of hydrogen is set to increase drastically as hydrogen is seen as a key element of the energy transition in Europe. The Finnish government is also planning to set a goal for electrolyser capacity. (European Commission, 2020a; Finnish Government 2021)

The proposed revision of the Renewable Energy Directive (RED II) also includes targets for renewable hydrogen and hydrogen-based synthetic fuels in transport and industry. The RED II amendment proposal sets a target that 2,6% fuel used in the transport sector should come from non-biological origins, meaning hydrogen or hydrogen based synthetic fuels. The proposal also states that in industry renewable fuels of non-biological origin should cover 50% of hydrogen used for final energy and non-energy purposes by

2030 (European Commission, 2021b). Furthermore, the EC proposes to set a goal for synthetic aviation fuels. For example, for the years 2035 and 2050 the proposed goals are 5% and 28% (European Commission, 2021c). If these proposed directives would realise, it would create a significant increase in demand for hydrogen and hydrogen-based fuels, supporting the ambitious electrolyser capacity goals of the European Commission.

A significant amount of electricity is needed to produce the targeted amounts of hydrogen. To ensure that the increase in electricity demand does not negatively affect greenhouse gas reduction targets, the European Commission wants to ensure that the electricity used to produce hydrogen and hydrogen-based synthetic fuels comes from renewable sources. The current Renewable Energy Directive states that: "To ensure that renewable fuels of non-biological origin contribute to greenhouse gas reduction, the electricity used for the fuel production should be of renewable origin. The Commission should develop, by means of delegated acts, a reliable Union methodology to be applied where such electricity is taken from the grid. That methodology should ensure that there is a temporal and geographical correlation between the electricity production unit with which the producer has a bilateral renewable power purchase agreement and the fuel production. For example, renewable fuels of non-biological origin cannot be counted as fully renewable if they are produced when the contracted renewable generation unit is not generating electricity. Another example is the case of electricity grid congestion, where fuels can be counted as fully renewable only when both the electricity generation and the fuel production plants are located on the same side in respect of the congestion. Furthermore, there should be an element of additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy." The current RED II sets the legislation specifically for transport fuels (Directive (EU) 2018/2001, 2018: article 27 (3)). However, in the amendment proposal released in the Fit for 55 -package, these calculation rules are proposed to be applied to renewable fuels on non-biological origin regardless of end-use sector (European Commission 2021b: article 1(16)).

Hydrogen Europe, a European association of hydrogen industry stakeholders, pointed out some challenges that they see from their perspective caused by the above discussed amendments. The additionality aspect in particular is seen as difficult. Hydrogen Europe states that the additionality criteria disincentivises investments into renewable hydrogen integration in hard to abate sectors, as they would have to step into the business of renewable energy development. The timing of investments with different lead times – renewable energy, electrolysers, and technological investments at the plant – is also seen as difficult. The association also views that the current legislative framework in the EU disincentivises investing into

electrolysers that provide grid balancing and flexibility services, as the use of curtailed renewable electricity from existing power plants would be limited. (Hydrogen Europe, 2021)

During the spring 2021, stakeholders in industry were concerned that the taxonomy regulation sets the emission threshold for producing hydrogen so low, to 2,26 kilograms of CO2 emitted per kilogram of hydrogen, that grid electricity could not be used at all times to produce hydrogen even in grids with low carbon intensities. Stefan Sundman stated in the article of Simon (2021) that industrial processes need hydrogen constantly and to ensure that, "hydrogen needs to come from the widest possible variety of low-carbon sources, especially at the early stages of development". In the Delegated Act published on June 4th 2021, supplementing the taxonomy regulation, the emission threshold was raised to 3 kilograms of CO2 emitted per kilogram of hydrogen. This means that in grids with low carbon intensities, such as in the Nordics, grid electricity could be used to produce hydrogen that is within the taxonomy emission thresholds. (European Commission, 2020c; COMMISSION DELEGATED REGULATION (EU) supplementing Regulation (EU) 2020/852, 2021)

3 Power system operation

The main task of the transmission system operator is to enable the transfer of electricity from power producers to electricity users across the country. The transmission grid covers the whole of Finland and connects large power producers and consumers and distribution networks together. Smaller electricity consumers and producers are connected to distribution networks which operate at medium to low voltage levels. The Finnish grid is a part of the synchronous Nordic power system together with Sweden, Norway, and Eastern Denmark. It also has direct current connections to Russia and Estonia (Fingrid Oyj, 2021a). The transmission system operator is responsible for keeping the reliability and operational security of the system at a required level. Maintaining the reliability and operational security of the system is based on thorough long- and short-term system planning and carefully planned operational processes. In Finland and in the Nordics, the system is planned to withstand any individual fault in the grid without leading to a disturbance or consequential failures. This is called the N-1 criterion. Any occurring disturbances need to be settled quickly to restore operational security. (Fingrid Oyj, 2021e)

This chapter provides an overview on how the electricity system is operated to keep production and consumption of electricity in balance, while keeping in mind operational security, stability and technical constraints imposed by the electricity transmission system, and how the electricity market functions to assist system operation.

3.1 Operational processes of power system operation

This section starts by first shortly presenting the ancillary services (AS) utilised by TSOs. Later, operational processes of power system operation that utilise market-based ancillary services are discussed more in depth. Additionally, forecasting and the use of forecasts in power system operation is presented

3.1.1 Ancillary services

Transmission system operators rely on ancillary services to maintain system security and stability. Ancillary services can also be called system services. Grid connected customers can be obligated to offer ancillary services for example by grid code requirements without receiving compensation or they can be procured by the TSO through market-based mechanisms. There are also mechanisms where participants receive a compensation for offering ancillary services, but they are not considered market-based, such as

dynamic network tariffs and flexible connection agreements (Chaves, Troncia, Silva, & Willeghems, 2021). Conventional controllable power plants with large rotational masses have long been providers of ancillary services for TSOs. But as they are increasingly being replaced by power converter connected variable renewables, there is a rising need to receive system services from new resources. Ancillary services are traditionally divided to frequency and non-frequency AS. Chaves et al., (2021) define the concepts as follows: "Frequency ancillary service means a service used by a transmission system operator for active power balancing. Non-frequency ancillary service means a service used by a transmission system operator or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability."

Frequency control is an example of power system operation that has long been utilising market-based ancillary services for its needs. However, the number, size and speed of frequency oscillations is growing as the share of variable and power converter connected renewables rises. Generation that is fully connected through power converters, such as type III and IV wind turbines and solar generation, do not provide the system any conventional rotational inertia that assists in slowing down frequency oscillations. In systems with high share of renewable generation inertia can become a scarcity and there is an increasing need to find new sources for it. This could mean utilising technical solutions, such as synchronous condensers or new markets for procuring inertia from system participants. (Silva, Alves, Ferreira, Villar, & Gouveia, 2021; Marrazi, Yang, & Weinreich-Jensen, 2017)

In addition to inertia, scarcity in short-circuit power can become apparent in highly renewable power systems. High short-circuit power assists in maintaining system stability against faults and helps in locating and disconnecting faults in the grid. The higher the short-circuit power, the stronger the system is against voltage fluctuations. Conventional power plants produce much higher short-circuit power to the grid during faults than renewables that are connected through power electronics. For example, type IV wind turbines limit the maximum short-circuit power output to 1,1 – 1,2 per unit of active power, whereas the same figure for conventional generation is in the region of 5 – 7 per unit. (Marrazi, Yang, & Weinreich-Jensen, 2017; National Grid ESO, 2020)

Whereas active power balance has an effect on frequency, the balance between production and consumption of reactive power affects the voltage in the power system. Frequency is a global value in the synchronous area, equivalent through the whole system, but voltage is a local value that varies in different parts of the network. Voltage has been traditionally controlled by

changing magnetisation levels of synchronous generators or with capacitors and reactors, which alter the local reactive power levels. Generally, synchronous generators are used to handle quick changes in local voltage levels and capacitors and reactors are used for slower management of reactive power levels. Voltage regulation done by synchronous generators is very quick which improves the system's ability to withstand faults. (Fingrid Oyj, 2011)

3.1.2 Power balance management

Maintaining the power balance between electricity production and consumption is the cornerstone of stable system operation. A mismatch in active power balance alters the frequency from the nominal 50 Hz in proportion to the deviation. If produced power is less than the consumption, the frequency decreases. And if produced power is higher than the consumption, the frequency increases. In Finland, the operating frequency area is 49,9 – 50,1 Hz. Maintaining the frequency within the operational range is currently accomplished mainly by controlling flexible generators, and to a lesser extent flexible loads, via the TSO operated reserve markets. Fingrid also has its own and leased reserve power plants to secure that there is enough reserve power capacity at all times. The reserve power plants are not used for commercial electricity production, and they are used for power regulation only after all offers received from market participants are activated. Power balance management and reserve markets are presented more in depth in the chapter 3.2. (Fingrid Oyj, 2011)

3.1.3 Congestion management

System operation has to also consider technical constraints of components in the power system. These constraints define the system's operational limits and transmission capacities. Transmission capacities are determined by system security calculations that consider both the operating state of the system and potential faults. The TSO ensures by transmission capacity allocation and congestion management that the operational limits are not exceeded. Transmission capacities are given to the power markets to allow for power transfer between different market areas. Fingrid aims to give the power markets as much transmission capacity as possible without endangering operational security. (Fingrid Oyj, 2011, 2021h)

Congestions in the grid can occur as a result of e.g., unplanned faults, planned outages or deviations in forecasted power production or consumption. Short-term congestions are handled commercially by means of countertrading. Countertrading is used to keep the power flow in the transmission line on an acceptable level and to ensure that set electricity

transactions can be realised. On the feeding side of the congestion, which is trying to transfer electricity to the receiving side of the congestion, Fingrid purchases downregulation to alleviate the congestion in the line. On the receiving side, Fingrid purchases upregulation to balance the power need on the receiving side. Downregulation can be a decrease in power production or an increase in power consumption. And vice versa, upregulation can be either an increase in power production or a decrease in consumption. Countertrading can also be called redispatching. (Fingrid Oyj, 2019)

Short-term congestion can be handled by activating geographically suitable offers from the reserve markets. Offers are activated during the operating hour and they can also be reserved for the upcoming hours if needed. If necessary, Fingrid's reserve power plants are utilised to quickly restore the power flow to desired level. The reserve power of Fingrid is deactivated as soon as possible when a sufficient amount of market offers is activated. Fingrid is currently piloting the use of intraday markets for congestion management during faults on cross-border connections (Fingrid Oyj, 2021b). For longer term congestion management, Fingrid uses open marketplaces. In case the regulation capacity in open markets is not sufficient or it is unable secure local operational security, bilateral agreements are needed. Fingrid asks for bilateral offers from market participants in Finland, or from neighbouring TSOs, if the congestion is on one of the cross-border connections. (Fingrid Oyj, 2019)

3.1.4 Forecasts in power system operation

It is expected that due to the increasing price volatility in electricity markets, electricity consumers will increasingly start to optimise their consumption based on the electricity price. This would lead to a situation where the demand of electricity is more dependent on the price of electricity. The electricity demand forecast Fingrid currently uses has season, day of the week, holidays, hour, temperature, wind speed and solar radiation as input values. Electricity price is not currently used as an input in the forecast, but it can be taken into account by the operators in the grid control center manually based on their experience and expertise (Fingrid Oyj, 2020). According to Summanen (2021), there are plans to possibly utilise realised day ahead market prices in the forecasts in the future.

Production, which is highly dependent on e.g., electricity price and weather conditions, and is subject to production and consumption in neighbouring countries, is much more complex to forecast. Fingrid uses production plans to forecast electricity production. Additionally, Fingrid has its own forecasts for wind and solar production, that can be used as a supporting tool on top of the production plans. The production of wind power can be forecasted to

the accuracy of one wind power park with Fingrid's own forecasts. In the case of solar power, production plans are not delivered as the resources are distributed to small sites and consumers (Summanen 2021). Production plans contain the planned electricity production of each hour for the following day. In Finland, production plans need to be sent to Fingrid by 17:30. Also, energy storages over 1 MW in size need to share their production, in practice discharging, plans to Fingrid. In practice, balancing responsible parties (BRP) are responsible of sending the production plans of production units in their portfolio to Fingrid. Sweden also requires consumption plans from over 50 MW industry consumers (eSett Oy, 2021). Transmission forecasts are based on production and consumption forecasts that take location into account. In Fingrid, transmission forecasts consider the location of production and consumption based on whether they are above or below the cross-section Central Finland, which is presented in Figure 10. Transmission forecasts can be utilised in system operation planning (Heikura, 2020).

Figure 10: Illustration of Cross-section Central Finland (Fingrid Oyj, 2021d)

Figure 11 illustrates use of forecasts in Fingrid. In the short term, meaning for the couple of upcoming hours, forecasts are used for system monitoring and to make intraday transmission forecasts (IDTF). Additionally, with the upcoming automated balancing process of the manual frequency restoration reserve's energy activation market (mFRR EAM), forecasts are used for the imbalance prognosis. Longer-term forecasts, such as the day-ahead transmission forecast (DATF), are used in system operation planning. They are also sent to the regional security coordinator (RSC). The RSC is in charge of system operation planning for the Nordic system. (Nordic RSC, 2021; Summanen, 2021)

In system operation planning the value of forecasts is limited to short-term operation planning. With growing share of wind power in the system, the accuracy of longer-term production forecasts has deteriorated because wind power has a significant impact on the dispatching production. The demand of electricity has long been hard to predict accurately for longer periods as it also highly correlates with weather. In addition, the geographical accuracy of forecasts is limited as discussed above. Currently it is common practice to utilise measured historical data to assess local power production and demand patterns in system operation planning. This gives a rough view on the local system needs for a chosen time-period, when assessing the need for, for example, redispatchable resources during longer planned interruptions. Power market modelling can be utilised to estimate transmission capacity requirements, but it is not very accurate for longer period estimations in local production and demand as the modelling results are highly dependent in weather patterns. (Huttunen & Mäkihannu, 2021)

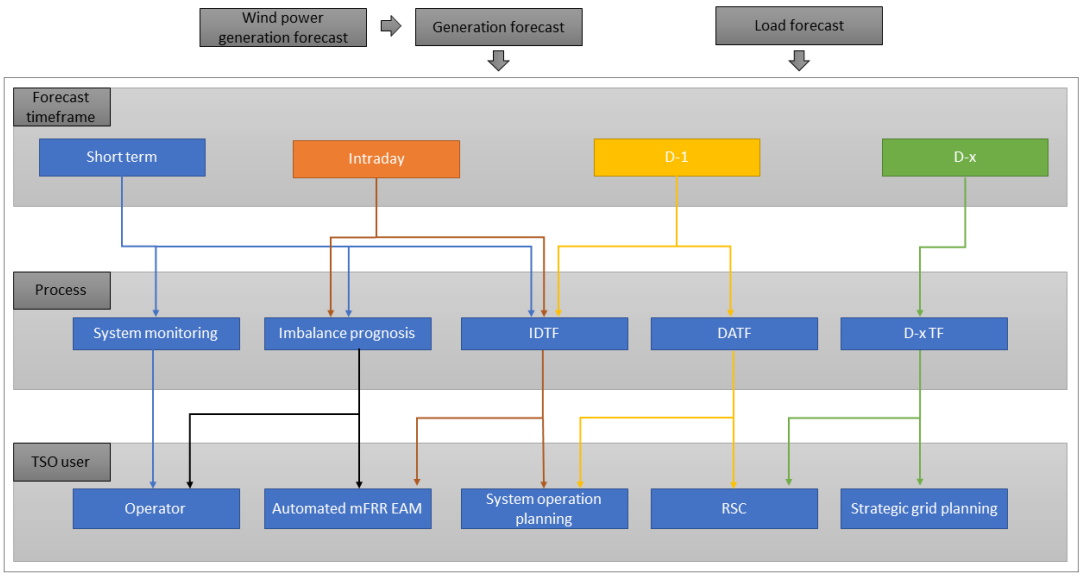


Figure 11: Uses and users of forecasts in Fingrid's processes

3.2 Electricity market structure and development

Electricity in the Nordics is traded through financial and physical power markets and with bilateral agreements between market participants. Physical power markets consist of three main market categories: day-ahead (DA), intraday (ID) and reserve markets. DA and ID are power markets that are operated by nominated electricity market operators (NEMO). Currently there are two NEMOs in Finland, Nord Pool and EPEX SPOT. Reserve markets are operated by the TSOs. (Energiavirasto, 2020; Fingrid Oyj, 2021c)

3.2.1 Day-ahead and intraday markets

Power exchanges act as platforms where planned production and estimated consumption of electricity meet to form balance of power. The largest share of power is traded through the DA market. In 2019, 73% of consumed electricity in Finland, 63,2 TWh, was traded in the DA market. In the Nordics, the DA auctions set electricity price for each hour of the day through an auction. The bidding closes at 13 EET on the previous day. The timeline of different physical markets and related actions are shown in Figure 12**.** The market clearing price for each hour is based on the crossing point of supply and demand curves that are aggregated for each hour. All market participants in one bidding area, or market area, are receiving or paying the same price for each hour. This is called pay-as-clear or marginal pricing. Finland is one market area, meaning the DA price across Finland is equal. If there are no transmission capacity limits, area prices between market areas will be equal, as electricity would flow from surplus generation and low-price areas to higher priced areas. Limitations in transmission capacity between market areas lead to decoupled prices between the market areas. (EPEX SPOT, 2021; Nord Pool, 2021)

Electricity producers and consumers can utilise financial markets to manage price risks of volatile power markets by hedging prices for a set period, e.g., for a year with financial products such as futures and options. The financial products are settled by referring to the realised DA market prices. Power purchase agreements (PPA) can also be used to manage price risks for longer time periods. A PPA is a bilateral agreement between an electricity supplier and consumer to deliver an agreed amount of electricity at a fixed price to the consumer. They have been growing in popularity during the recent years due to the decreased electricity production costs of variable renewables and their need for a stable income to assist in financing capital intensive investments. Large electricity consumers are also increasingly looking to cover their consumption with renewable electricity, to reduce their environmental impact. PPAs can be classified as either physical or financial agreements. In

physical PPAs, the produced electricity is directly transferred to the customer through the grid. In financial PPAs, the producer and consumer trade power through the power markets and the difference between the agreed and the market price is settled afterwards. Physical PPAs are more common in the Nordics (Copenhagen Economics, 2020). In practice, market risks for fixed demand are easier to manage than for variable demand, which is prone to price and volume risks. Futures can be used to hedge the price of electricity for loads corresponding to the average daily power. However, they cannot be used to secure electricity purchases on an hourly basis. DA and ID markets must be used to match hourly purchases of electricity with the demand. On the other hand, the advantage of variable - optimised - consumption is that it is able to utilise the lowest cost hours in the DA and ID markets. However, this requires optimisation and expertise in electricity procurement, which is not necessarily the focus for all electricity consumers.

Intraday markets allow market participants to balance the production and consumption of electricity closer to the delivery hour, as seen in Figure 12. Accurate forecasting of production and consumption of electricity can be difficult on the DA market, as the time between bidding closure and the delivery hour is long. For example, weather forecasts have significant influence on production and demand forecasts, as they affect e.g., renewable energy production and heating energy consumption. In 2019, 1,0 TWh was traded on the ID market (Energiavirasto, 2020). The price in the ID market is set by pay-as-bid principle. Buy and sell prices are matched starting from the highest buy prices and lowest selling prices and the selling offers receive the price according to their bid (Nord Pool, 2021).

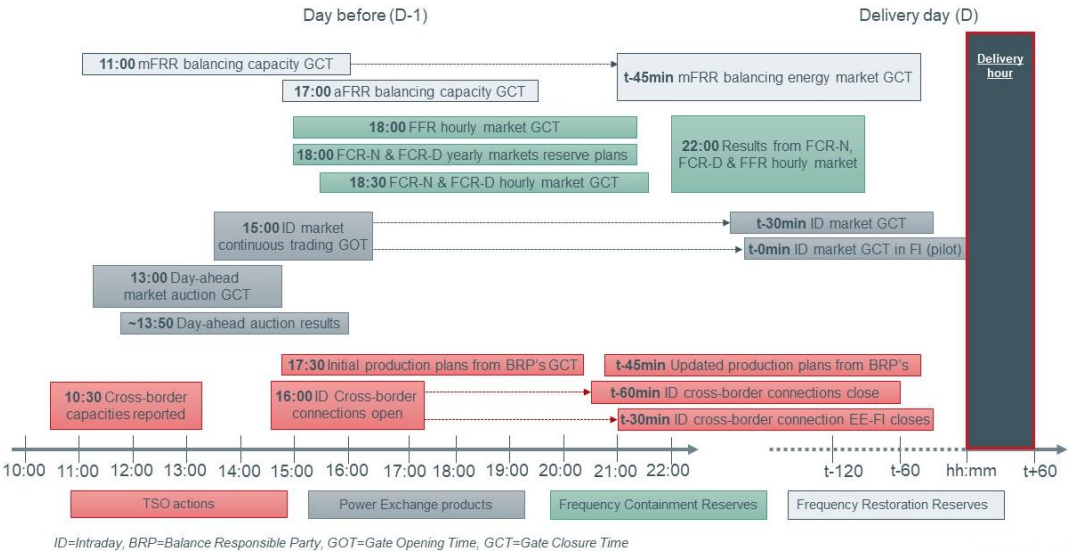


Figure 12: Market trading timeline of physical products (modified from Fingrid Oyj, 2021c)

3.2.2 Reserve markets

One of the primary tasks of the TSO is to maintain a constant balance between production and consumption of electricity. All participants in the electricity system cannot in practice take care of their own power balance, which is why they have a balancing responsible party, who is responsible for maintaining the power balance of the sum of clients included in their portfolios. BRPs can be for example electricity producers, consumers, or suppliers. By keeping their portfolio in balance, BRPs help the system to be in balance. Ultimately, the TSOs are responsible for balancing the power balance deviations of the BRPs. (Khodadadi et al., 2020)

TSOs maintain power balance by operating reserve markets. Balancing service providers (BSP) can offer balancing services to the TSOs via reserve markets. BSPs can be for example power generators, demand response facilities or storage operators, which can alter their production or consumption of electricity (Khodadadi et al., 2020). Reserves are classified based on their intended use, which are presented in Figure 13 (Fingrid Oyj, 2021f).

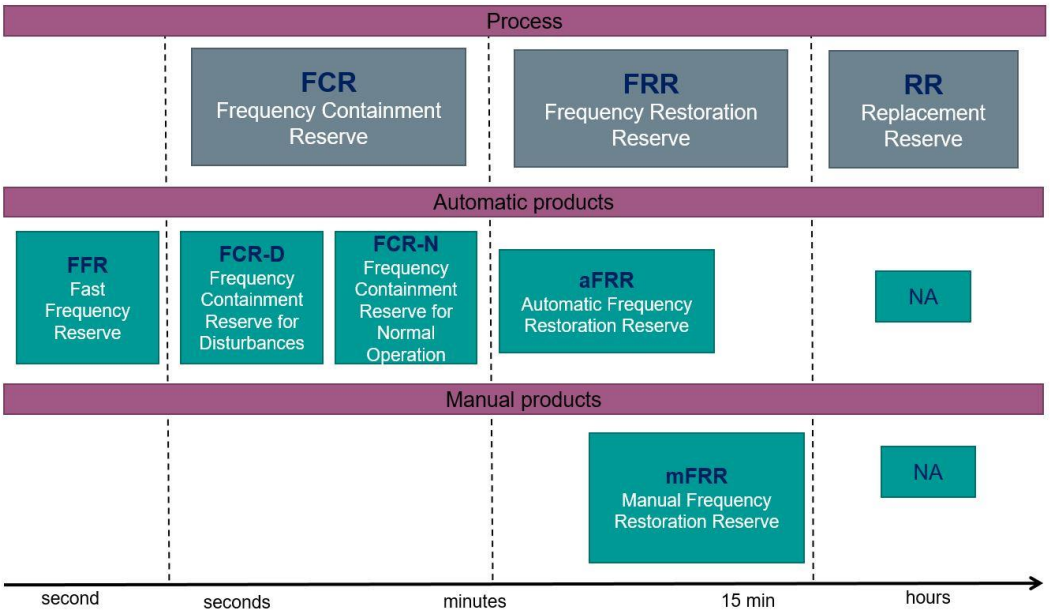


Figure 13: Reserve products in Finland (Fingrid Oyj, 2021f)

Frequency containment reserves (FCR) can respond to deviations in power quickly and they are automatically activated based on local frequency measurements. Frequency containment reserves for disturbances (FCR-D) are activated during large frequency deviations. In Finland, there are separate products for up and down regulation for disturbances. Procurement of FCR-D down started in the beginning of 2022. Frequency containment

reserves for normal operation (FCR-N) are used continuously to keep the frequency between acceptable limits. FCR reserves are capacity markets, but BRPs also receive reimbursement based on the activated energy. However, as the activated energy is typically relatively small, the major incomes for the service providers come from the capacity payments (Khodadadi et al., 2020). FFR is the fastest of all reserve products. It is procured for hours with forecasted low inertia to respond to large underfrequencies quickly. (Fingrid Oyj, 2021f)

Frequency restoration reserves are activated after the FCR products to bring the frequency back to 50 hertz. Restoration reserves are divided to automatic (aFRR) and manual (mFRR) products. Reserves participating in aFRR markets are quicker to activate and they can be activated automatically by a centralised controller. mFRR reserves can be slower to activate and they are activated manually (Khodadadi et al., 2020). Both restoration reserves have capacity markets to ensure there is sufficient balancing capacity in the system. mFRR also has an energy market, where flexible resources can offer their services without committing or bidding to the capacity markets. All markets operate on a marginal pricing principle, meaning that the price paid for all participants is based on the most expensive activated bid. In Finland, mFRR is the largest reserve product in terms of capacity. For example, for the year 2021, Fingrid had an obligation to procure 880–1100 megawatts of mFRR reserves (Fingrid Oyj, 2021g). Summary of technical requirements for all reserve products can be found in appendix A.

At the moment, there are large developments taking place in power balance management and reserve markets in the Nordics. The development is driven by the Nordic Balancing Model (NBM) program. The goal of the development is to allow for Europe wide market integration of reserve markets, specifically the aFRR and mFRR energy activation markets, and to improve the system's ability to integrate volatile renewable energy sources. The largest change challenging the operational processes of system operators and market participants is the change to a 15-minute imbalance settlement period. Currently the imbalance settlement period is one hour. To settle and price imbalances in 15-minute resolution, the energy activation markets also have to operate in 15-minute resolution, which requires extensive automatization of, for example mFRR energy market processes, as grid operators have very little time to make manual balancing decisions and operations during the shorter time period. The change also enables the ID and, later, the DA markets to operate at a 15-minute market time unit. (Khodadadi et al., 2020; Nordic Balancing Model, 2021)

The Finnish and Nordic system relies heavily on mFRR products, which can be activated proactively based on forecasted power imbalances or reactively

based on real-time system needs during the operating period. Proactive activation of mFRR relies heavily on high accuracy imbalance forecasts. The development in power markets is moving towards shorter market time units and market gate closure times closer to the operating hour. The shorter market time unit means that the imbalance energy volume is inherently smaller for each operating window. Also, the direction and price of imbalances more accurately represents the systems needs when the imbalance settlement period shortens. Gate closure times closer to the operating period mean that the market participants have higher accuracies in their balance forecasts and tools to settle them before the operating period (Haberg & Doorman, 2016). For example, in Finland, the gate closure time for ID markets is at the start of the operating period, as seen in Figure 12. As stated by Pakalén (2019), the upcoming market development means that Fingrid should lean towards reactive balancing in the future. A move towards a more reactive balancing philosophy would lower the need for proactive balancing decisions and therefore lessens the importance of accurate forecasts in power balance management.

4 Sector integration technologies

In many future assessments of the energy system, sector integration is seen as a critical source for increasing the flexibility in the power system. The need for flexibility increases as the share of variable, weather dependent, production in the power system increases. A common definition for flexibility in power systems does not currently exist as the term is used for different purposes based on the focus of the studied aspect. One definition for power system flexibility is the system's ability to handle uncertainties and intentional and unintentional deviations in electricity generation and demand (Akrami, Doostizadeh, & Aminifar, 2019). This definition is a relevant one also for this thesis. To a great extent, the term flexibility is used to describe utilising flexible resources for power balance management and frequency control. However, the use of flexibility can also cover other more local needs of power system operation such as voltage control and congestion management (Paiho et al., 2018).

Flexible resources can be classified based on what timescale they can provide services to the system's needs. Short-term flexibility can be used for operational needs, such as frequency control and short-term congestion management. Short-term flexibility is currently utilised through reserve markets or intraday markets as presented in the previous chapter. Long-term flexibility can be utilised for longer term operational needs, for example congestion management needs during long faults or planned interruptions or to ensure generation adequacy during times with low renewable generation.

Storage is an essential tool in meeting the increasing flexibility needs, especially those of the power system, which is the most impacted by the penetration of variable renewables. A high share of renewables in the system can create a need for long-term and seasonal storage, for example to provide electricity during periods of several days with very little wind. In terms of sector integration, the ability to store the end-product of electricity use, such as heat or hydrogen, allows the consumer to concentrate their electricity consumption to lower price hours and bringing flexibility to their electricity use. Storage of heat and hydrogen is seen as a key solution to increase flexibility in the energy system as the long-term storage of energy is cheaper than, for example, with electrochemical batteries, which have a high capital cost per unit of energy. The capital cost of batteries is currently at approximately 120 euros per kilowatt hour of electricity (BloombergNEF, 2021). For hydrogen, the capital cost is estimated to be around 0,5 to 2,6 euros per kilowatt-hour of hydrogen (LHV) in salt caverns, depending on the size of storage. In lined rock caverns, the capital cost is estimated at around 1,2 to 4,4 euros per kilowatt-hour (Papadias & Ahluwalia, 2021). Hydrogen

storage tanks are significantly more expensive, with cost estimates at around 13 euros per kilowatt-hour (Houchins, 2019). For heat storages, the capital costs from existing projects are listed at around 1 to 8 euros per kilowatt-hour (Espagnet, 2016). With longer term storage of the end-product, the consumer can cut their consumption during periods of low winds and high prices.

There is still limited understanding of the technologies enabling sector integration. This thesis focuses on studying the behaviour of new electricity demand which arises from the growing share of electrification in all energy sectors. According to current estimates, sector integration does not bring significant changes to the technology portfolios in electricity production before 2035 (Fingrid Oyj, 2021d; Forsman et al., 2021; Roques et al., 2021), which is the period under review in the thesis. It should be noted, however, that the development of electricity demand is tightly linked to the development of electricity production, and vice versa. Roques et. al. (2021) estimate that increasing the amount of demand side flexibility is critical for cost-efficient integration of renewables and electrification. Reduced availability of demand flexibility would raise the need for supply-side flexibility and storages, as well as additional generation capacity to offset storage losses, which would result in much higher overall system costs and power prices. Both cases can also raise the concern of generation adequacy during long periods with low renewable energy production if there is not enough incentive to invest in long-term demand-side or supply-side flexibility.

This chapter focuses on giving insight on what use cases the technologies are utilised for, by which principles the technologies behave, how they can be expected to be operated and what kind of flexibility they can potentially offer to the power system. The thesis focuses on the most relevant technologies for process and district heating and hydrogen production, namely large-scale heat pumps, electric boilers, and electrolysers. The potential capability of the technologies to provide ancillary services is also briefly discussed.

4.1 Power-to-Heat in district heating

This section starts with a short overview of large-scale compression heat pump and electric boiler technology. After that, the typical use cases and operation of heat pumps and electric boilers is analysed based on experiences from Finland and other EU countries. Lastly, the participation of the technologies on the power markets is discussed, as well as the factors influencing the development of power-to-heat in district heating.

4.1.1 Technologies

1) Heat pumps

Compression heat pumps transfer heat from a low temperature level to a higher temperature level by utilising the same technological principle as refrigerators. Heat pumps are well-known technologies that have been widely used for large scale refrigeration. Heat pumps use a closed process to extract heat from a heat source and transfer it to a heat sink at a higher temperature. They can be compression type heat pumps using electricity or fuels or absorption heat pumps using heat from for example steam, hot water, or oil. This thesis focuses on compression heat pumps utilising electricity. Working scheme of a compression heat pump is presented in Figure 14. (Danish Energy Agency, 2020)

Heat pumps can be utilised for residential and commercial heating, industrial process heat production and district heat production. Heat pumps are often built as a supplement to existing heat plants. Due to their high investment costs large scale heat pumps are typically constructed with a capacity corresponding to half of the peak heat demand. As a result, a heat pump may generate 85 to 90 percent of the yearly heat demand as a base load unit, with peak load or backup units supplementing at peak load (Danish Energy Agency, 2020). In the case of Helsinki, the peak heat demand in the DH network during the years 2015–2020 was 2600 MW. During the six-year period, for 90 percent of the time the heat demand was below 1310 MW. For 99 percent of the time the heat demand was below 1860 MW (Helen, 2022a).

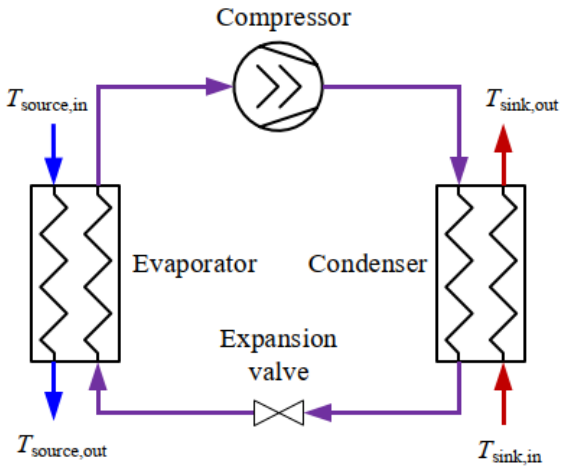


Figure 14: Heat pump cycle (Bach, 2014; Danish Energy Agency, 2020)

The theoretical coefficient of performance (COP) factor is dependent on the temperature of the heat source and the heat sink. For a single cycle, the Carnot method for COP calculation can be used. For a heat pump system with several Carnot cycles, which is typically the case with large temperature

differences in DH heat pumps, the Lorenz method is preferred. The equation for Lorenz COP is shown in equation 1.

$$COP_{Lorenz} = \frac{T_{lm,sink}}{T_{lm,sink} - T_{lm,source}}, \qquad \text{where } T_{lm} = \frac{T_{in} - T_{out}}{\ln(\frac{T_{in}}{T_{out}})} \qquad (1)$$

Where T_{lm} is the logarithmic mean temperature of the heat exchangers. The difference between the theoretical and practically achievable COP is dependent on component efficiencies, heat exchangers, refrigerants, and other factors. Ultimately in practice the COP factor describes the ratio between the heat delivered and the electricity used by the heat pump as illustrated in Figure 15. (Danish Energy Agency, 2020)

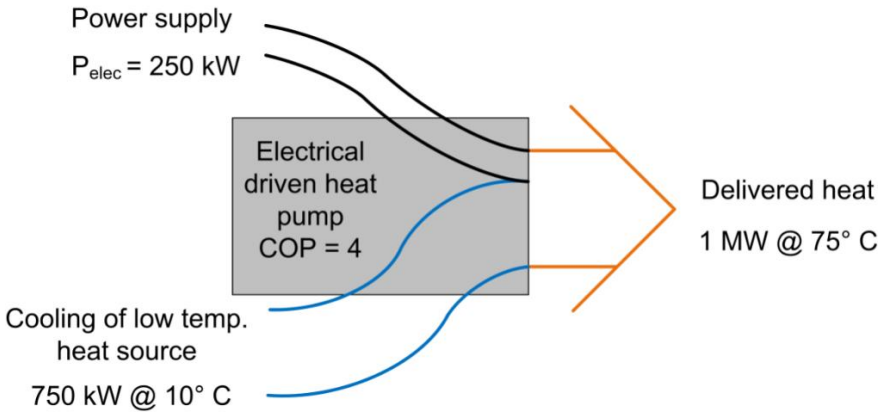


Figure 15: Illustration of the energy flow in a heat pump and the effect of the coefficient of performance factor (Danish Energy Agency, 2020)

The use of large-scale heat pumps in district heating is seen to increase significantly in aims to decarbonise district heating. As seen in Figure 3, waste and ambient heat recovered by heat pumps covered roughly 10% of DH production in Finland in 2019. Figure 16 shows the capacities and commissioning years of installed heat pumps in DH networks in seven European countries with largest installed and operational capacities in 2016. During recent years, the capacities have been growing especially in the northern countries. Sweden saw significant growth in heat pump capacities during the 1980s due to a surplus of electricity production caused by new nuclear power plants. Given the country's limited export capacities, any excess electricity had to be used within the country, so a legal framework was established to support an increase in electricity demand, which included the installation of individual and large-scale electric boilers and heat pumps (David, Mathiesen, Averfalk, Werner, & Lund, 2017).

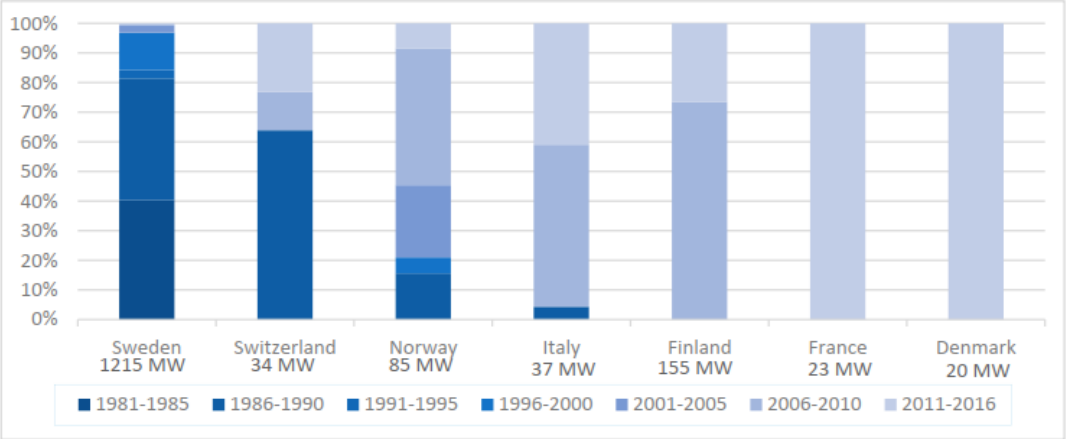


Figure 16: Capacities and installation years of DH heat pumps in seven countries with the greatest currently operational capacities (David et. al., 2017)

In the study of David et. al. (2017), the existing large-scale heat pumps in European DH systems were analysed based on their heat sources, technical characteristics, and types of operation. Heat pumps with over 1 MW in thermal output were included in the study, leading to a total of 149 units with a total thermal output capacity of 1580 MW. The data for the study was collected between September 2015 and February 2017. According to the authors, the collection was done: "mainly through online research from heat pump manufacturers, utility companies, newspapers and fact sheets of energy companies, presentations and databases of national DH associations. However, valuable information was also provided through email and phone correspondence with project, utility, association and manufacturer representatives and in interviews with experts."

Table 1 presents the capacities of installed heat pumps per heat source used in the study of European DH heat pumps by David et. al. The heat source has a big impact on the temperature lift required and the COP of the heat pump. Consequently, it also has a high impact on the marginal operating cost of heat production. Figure 17 presents the operating temperature range of heat pumps with accessible data in the study of David et. al., where orange bars represent HPs built before 2006 and blue bars are HPs commissioned after 2006. As per equation 1, with a lower temperature lift, HPs are capable of achieving a higher COP factor. As seen in Figure 17, most heat pumps are supplying temperatures above 70 degrees Celsius. The study specified the output temperature range for 1190 MW worth of HP capacity in the study. The ranges were below 70, between 71 and 80 and above 80°C. The installed capacities were 40, 725 and 425 MW respectively. The average COP of HPs on the specified temperature ranges were 4,5, 3,6 and 3,7. (David et. al., 2017)

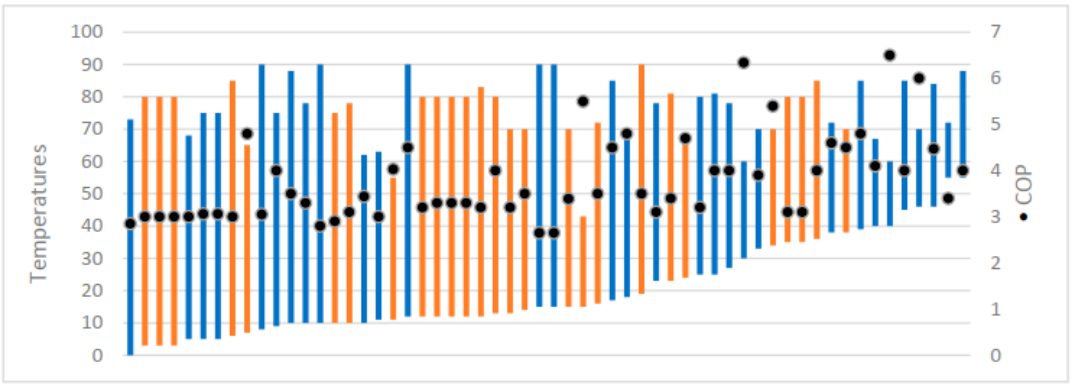


Figure 17: Operating temperature range and COP of heat pumps with accessible data (David et. al., 2017)

In Europe, sewage water is the most common heat source for DH heat pumps with almost 900 MW of capacity installed. Sewage water is a long-term stable heat source which makes it attractive for long-term investments. Ambient heat and seawater are also considered long-term stable heat sources. Industrial excess heat is a prominent heat source due to its high temperature, but it lacks long-term stability, as it is dependent on the industry supplying it. For example, in Swedish DH systems between 1980 and 2013 the installed capacity of DH heat pumps utilising industrial excess heat dropped from 196 MW to 86 MW, meaning a reduction of 56%. For the same period, the installed capacity for heat pumps utilising ambient and sewage water decreased 19 and 15% (Averfalk, Ingvarsson, Persson, Gong, & Werner, 2017).

Table 1: Heat sources for the heat pumps in the study of David et. al. (2017)

Type of Heat Source	Capacity (MW)	Percentage of Total Capacity	Number of Units	Average Capacity Per Unit (MW)	Temperature Range (°C)
Sewage water	891	56%	54	17	10–20
Ambient water	390	24%	34	11	2–15
Industrial waste heat	129	8%	28	5	12–46
Geothermal heat	97	4%	19	5	9–55
Flue gas	40	2%	7	6	34–60
District cooling	30	<2%	4	7	0–9
Solar heat storage	4	<1%	3	1	10–35
Total	1580		149		0–60

2) Electric boilers

Electric boilers are heat only boilers that use electricity as fuel to produce hot water or steam. Small-scale electric boilers are common in residential use as hot water heaters. Large-scale electric boilers can be used for producing industrial process heat or district heat. Electric boilers have very low investment costs, but they are less efficient than compression heat pumps in heat production per electricity used as they do not allow for heat extraction from external sources. In EBs, the conversion of electrical energy to thermal energy is nearly 100 percent efficient. The operating cost of EBs is dependent

on the electricity price. As EBs have low investment costs and comparably high operating costs, they are typically installed as peak load units with low amount of full-load hours (FLH) similar to oil or gas boilers. Generally, up to capacities of 1-2 megawatts, the heating in electric boilers is done by resistive elements immersed in water. In larger scale applications, electrode boilers are used. In electrode boilers, electrical current flowing through streams of water heats up the water. Heat production can be altered by changing the electrical current or water flow. (Danish Energy Agency, 2020)

According to (Danish Energy Agency, 2020) the use of EBs in district heating in Denmark has been largely driven by the demand for ancillary services rather than the demand for heat. However, examples of electric boilers that operate on the day-ahead market can be found. In Finland, EBs have not yet participated in reserve markets (Korhonen, 2019). With increased amount of volatility in the electricity market, the potential for using EBs can be seen to increase in the future. Modern electric boilers can be used for fast frequency regulation reserves, such as FCR markets, if they are operating in stand-by mode. The warm ramp-up time from 0 to 100% load is 30 seconds. Cold start can be done in five minutes. Modern electric boilers can have very small stand-by consumption, related only to the electricity consumption of internal pumps. Older boilers can consume 5–10% of full load in standby operation. Parat, a large manufacturer of electrode boilers, advertises its electrode boilers to have zero-load during standby mode (PARAT, 2022). Table 2 presents technical data of the regulation ability, start-up times and minimum load concerning compression heat pumps and electric boilers. Regulation ability illustrates the dynamic load changing capability of the technologies. For example, compression heat pumps can change their load 10% during a one-minute period. (Danish Energy Agency, 2020)

Table 2: Relevant technical data of compression heat pumps and electric boilers (Danish Energy Agency, 2020)

	Regulation ability (% per minute)	**Warm start, 0–100% load (minutes)**	**Cold start, 0–100% load (minutes)**	**Minimum load (% of full load)**
Compression heat pumps, excess heat or air source	10	6	60	25
Compression heat pumps, seawater	10	12	120	25
Electric boilers	100	0,5	5	5

4.1.2 Use cases

1) Heat pumps

Heat pumps are typically used to supply base load or secondary load. The use of the heat pump can be estimated from the realised operating hours of installed HPs from which the capacity factor can be derived. Heat pumps supplying base load are operating continuously and are supplying a certain share of the basic heating need in the DH network. These devices can have full load hours (FLH) in the range of 7000 – 8000 hours. In the study of large HPs in Sweden (Averfalk et.al., 2017), units with full load hours around 5000 hours were considered base load units, as in the low-carbon roadmap study of AFRY (2020). Heat pumps serving secondary load have fewer operating hours and lower capacity factors. However, the flexible operation of heat pumps is somewhat restricted by the mechanical wear on components during start-ups. HPs so far have not been designed for flexible operation and frequent start-ups. According to experiences from large Swedish heat pumps, daily start-ups are near to the limit of normal operation but still acceptable for the large electrical motors which are seen to be the most vulnerable components due to the direct start sequences. This can also be seen in the start-up costs listed in the technology data catalogue of Danish Energy Agency (2020). For HPs, the start-up cost is 10 €/MW/start-up whereas for EBs the cost is zero. In Gothenburg however, two 50 MW units have been operated flexibly on a daily basis since the early 1990s solely based on the electricity price (Averfalk et.al., 2017).

Figure 18 shows the aggregated and arithmetic average capacity factors of HPs in Swedish DH systems. The fact that the arithmetic averages are lower than the aggregated averages shows that small heat pumps generally have lower capacity factors than larger ones. During the period between 1986 and 2001 the aggregated average capacity factor was 56%, meaning that the HPs were operating as base load units. During this period, the amount of surplus electricity was high in the Swedish system due to high amount of new installed nuclear capacity, leading to low electricity prices and low operational costs for heat pumps and electric boilers. During the more recent period between 2002 and 2013, the capacity factors have been declining to around 40%. In 2013, the aggregated capacity factor was 37% which is equal to 3220 full load hours. Possible explanations for the recent evolution include the introduction of new competing policy instruments, as well as higher electricity prices and taxes. The result was a change in the merit order between heat pumps and CHP plants in the heat supply mix because the economic value of generating and selling electricity in CHP plants became greater than the value of using electricity in heat pumps. (Averfalk et.al., 2017)

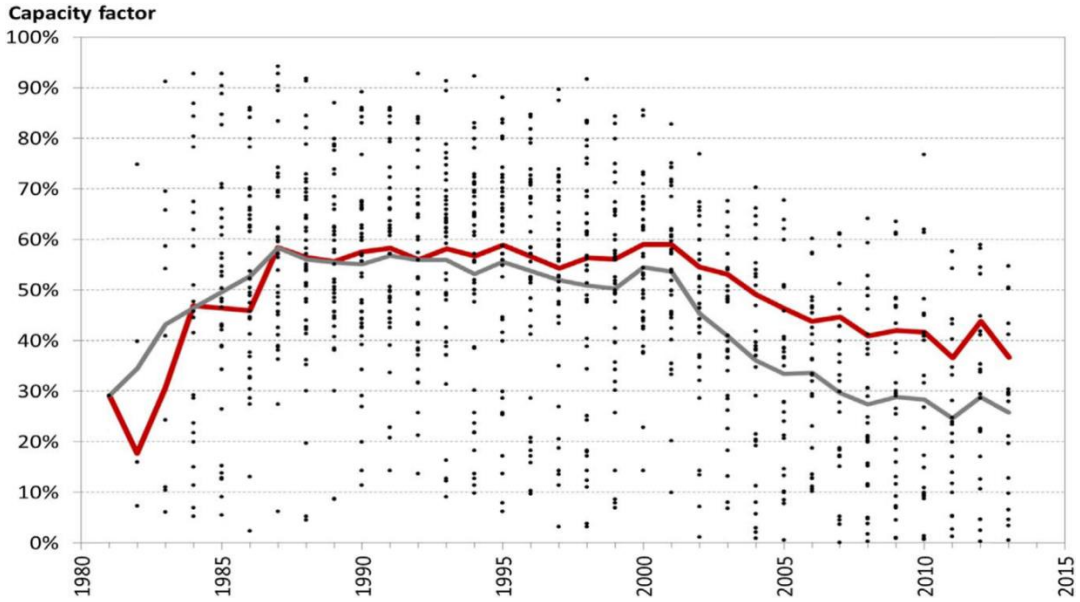


Figure 18: Aggregated (redline) and arithmetic (grey line) average values of DH HP capacity factors per company and year (Averfalk et.al., 2017)

In Finland, statistics of heat production and electricity consumption of DH heat pumps can be found in the district heating statistics of Energiateollisuus (2021b). Operational statistics of heat pumps in four DH networks could be derived for years 2014–2020. Some large-scale DH HPs were left out of the analysis due to incomplete data. In the case of Helen, the data consists of two separate HP facilities starting from the year 2018. For other DH operators the data covers one facility. All collected data that has been used for the analysis can be found in appendix B. Figure 19 shows the full load hours of DH heat pumps included in the analysis. As seen in the figure, FLH of Fortum's Suomenoja 4 HP have been consistently close to or over the yearly maximum amount of 8760 hours. Based on these statistics, this means that the operating power is at times higher than the listed 11 MW, which could be reasoned based on the technical data sheet published by Friotherm (2015). In any case, according to the statistics, the Suomenoja 4 HP facility has been operated as a base load unit after its installation.

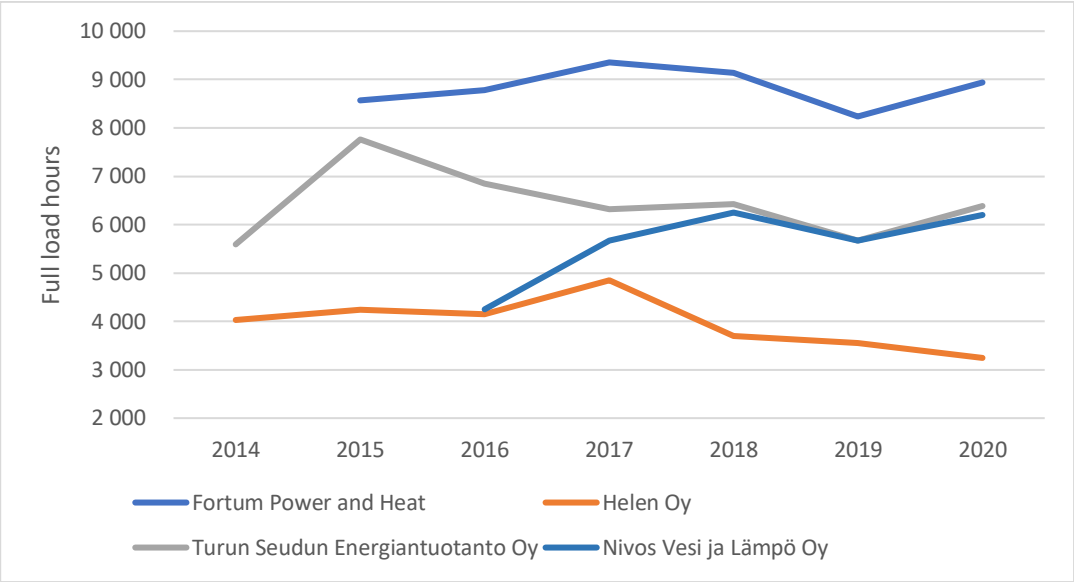


Figure 19: Full load hours of large-scale HPs in four Finnish DH production companies (Energiateollisuus, 2021b)

Other than the HP of Nivos Vesi ja Lämpö, the HPs are also used for district cooling (DC). The HP of Nivos Vesi ja Lämpö uses data centre waste heat as a heat source. Other facilities use lower temperature heat sources such as sewage water and DC return water. Based on the technical data sheets of HP supplier Friotherm (2015, 2017b, 2017a;), the operating range of the HPs can differ quite significantly between the summer and winter season as the heat source temperature increases in the summer and the heating need increases in the winter. For the Suomenoja 4 and Katri Vala heat pumps, the supply temperature lowers to ~60°C during winter operation. This implies that supplementary heating methods are needed on top of the HPs to raise the temperature to match the DH network temperature. This is also stated in the report of Valor Partners (2016), where interviews of DH operators were conducted. In the case of Helen and Nivos, the HP supply was primed with heat only boilers during peak times up to 115°C. In Kakola, the supply temperature rises to 82°C during winter operation and priming is not necessary as the heat is supplied directly to the local heat distribution network.

Table 3: Heat sources and temperatures for analysed heat pumps (David et. al., 2017; Friotherm, 2015, 2017b, 2017a; Helen, 2019)

	Heat source	Source temp. (°C)	Supply temp. (°C)	District cooling
Fortum Power and Heat				
Suomenoja 4	Sewage water	10–14	60–65	Yes
Helen Oy				
Katri Vala	Sewage water	10–20	62–88	Yes
Esplanadi	DC return water	-	-	Yes
Turun Seudun Energiantuotanto Oy				
Kakola	Sewage water	12–18	75–82	Yes
Nivos Vesi ja Lämpö Oy				
Yandex LTO	Data center waste heat	36	85	No

Lowering the maximum design temperature of district heating networks is seen as a key tool to improve the viability and efficiency of waste and ambient heat use and non-combustion based heating methods. However, the change to lower temperatures in DH network requires changes in heat exchangers on the consumption side and possibly large changes in heat distribution networks, as less heat energy can be transferred in existing pipelines with lower temperatures. Currently, the design temperature in Finnish DH networks is typically 115°C. The correlation between the district heating network temperature and ambient temperature in Helsinki's case is shown in Figure 20. However, if the HP facility is located close to consumption, it can already feed in lower temperatures to the DH networks, as is the case for the Kakola heat pump facility. Low temperature DH networks can decrease the use case for peak boilers, also electric boilers, as they would not be needed to prime the heat produced by HPs. Therefore, the use of low-temperature DH networks could actually decrease the use case for HOBs that are used to prime the heat from HPs, which could mean that the flexibility of HPs decreases due to the decreasing amount of alternative heat sources. As seen in previous chapters, DH HPs are not supplying heat at temperatures over 90°C at the moment.

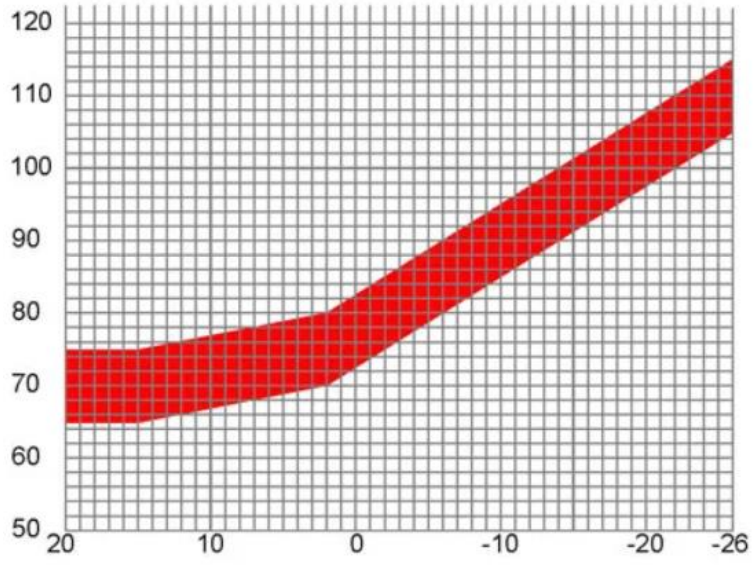


Figure 20: District heating network temperature (red) as a function of ambient temperature in Helsinki (Helen, 2022b)

2) Electric boilers

Electric boilers are a low investment cost technology, where the variable cost of heat production is directly connected to the cost of electricity, including taxes and grid charges. Due to the cost structure, the technology is used for low amount of hours during the year and typically during low electricity price hours. Installing and operating electric boilers is only cost-effective if it decreases the consumption of fuel in other production units in the district heating system and if electricity is less expensive than the fuel. In Denmark, the increase of electric boiler capacity has been partly driven by revenues from ancillary service markets, mainly downregulation markets, due to increased wind power in Denmark and Northern Germany. Due to the quick ramping capability, electric boilers are able to participate in fast downregulation required in FCR markets. For Northern Germany, the activation of Danish electricity consumption has proved to be a cost-effective approach for integrating surplus wind power, when forced downregulation of wind generation is the alternative during peak load hours. (Danish Energy Agency, 2020; Schweiger, Rantzer, Ericsson, & Lauenburg, 2017)

As a peak load technology, the energy delivered by EBs is low, but the installed capacity in terms of power and peak electric load can be significant. Due to the high COP of heat pumps, the electric load is not as high with an equivalent heat output. In the case of Sweden, the maximum power requirement of power-to-heat installed in district heating in 2018 was 1 540 MW of which 389 MW came from HPs and 1151 MW from EBs (Bolander, 2018). In Denmark in 2018, the peak electric load from power-to-heat in DH would have been 700 MW of which around 50 MW came from HPs and 650

MW from EBs (Dansk Fjernvarme, 2020). According to the Finnish DH statistics from 2020, the peak electric load from listed DH heat pumps can be around 71 MW and 160 MW from electric boilers (Energiateollisuus, 2021b). The significance of EBs and their flexible operation in terms of quick power changes can therefore be much greater than that of heat pumps.

Due to the cost structure and capabilities of the technology, EBs can be seen to operate beneficially from the power system operation perspective, as they are used during the low electricity price hours, which do not typically occur simultaneously with peak loads. However, with the development in the electricity and energy sector, in the future the low-price hours can be the ones with the highest loads if electricity intensive processes such as power-to-heat and hydrogen production through electrolysis reach large quantities. However, this requires a high amount of installed VRE and low marginal cost capacity to keep the market price low even with the increased demand of electricity. This can be a challenge to transmission capacities in the electricity network, especially in urban areas with large DH networks, if high power-to-heat loads due to low electricity prices occur simultaneously with other peak loads. In Denmark, most distribution system operators (DSO) limit the available electric power for boilers during peak load hours. Having complete grid connectivity at all times often results in higher grid connection costs, lowering the economics of the electric boiler project. In Denmark, a minimal load can be negotiated depending on the DSO and the grid state (Danish Energy Agency, 2020). Limiting the power requirement of a centralised technology can be much easier for the system operator than limiting distributed power needs coming from various consumption points. However, it can decrease the availability of regulation power availability for the power systems operational needs during peak demand hours, as gathering it from distributed sources can be harder to manage.

Currently it is expected that electric boilers operate during low-electricity prices. However, in a non-combustion based system electric boilers could be utilised similar to natural gas or oil peak boilers to produce heat even during high electricity prices. In terms of cost-competitiveness this would require that the price of alternative fuels or associated costs, such as CO2 abatement costs, rise to higher levels than the cost of electricity used for electric boilers. Individual companies can also have ambitious decarbonisation plans that favour the use of non-combustion based technologies. For example, in the case study of Tampere in the non-combustion based scenario, the peak load of electric boilers is 350 MW, which is equivalent to the city's typical peak electricity load during cold winter days. However, as pointed out in the study of Joronen, Salhoja and Vähätiitto (2021), the use of EBs during peak load hours is not truly carbon neutral as the electricity during peak load hours is normally quite carbon intensive due to the use of peaker plants in electricity

generation. Another weak signal of EB use for peak loads comes from Fortum. Fortum is aiming to partner up with a large data centre operator to purchase waste-heat from them, which is then primed with heat pumps to high enough supply temperature for the DH network. In an article about the electricity use of the planned project it is stated that the waste-heat would be needed to be primed also with electric boilers during cold periods, which would lead to EBs being used during peak load periods also in the DH network (Fortum, 2021b). However, it should be safely assumed that DH operators choose the lowest marginal cost heat production method for their heating need, meaning that during very high electricity prices alternative technologies, such as CHP plants or heat only boilers using biomass or fossil fuels, are preferred.

4.1.3 Participation in power markets

Electric boilers and heat pumps in the DH system can provide demand side flexibility, as they can be turned on when there is a lot of available electricity, such as during days with heavy winds, and turned off when the electricity supply is limited, e.g. days with no wind. EBs and HPs can also act as demand response units for the system's needs through reserve markets. Some DH HPs in Finland have participated in the reserve markets, more specifically in the balancing energy markets and in the peak load capacity reserves as demand response units (Fingrid Oyj, 2022; Korhonen, 2019). However, in order to take use of the flexibility potential of electric boilers and heat pumps, two key conditions must be met: 1) There are incentives for DH businesses to invest in EB and HP capacity; and 2) EBs and HPs are the optimal dispatch choice when power prices are low, but suboptimal when power prices are high. While the first criterion requires a low long-term marginal cost of heat from EBs and HPs, the second condition requires a sufficiently low short-term marginal cost during low power prices. As a result, the two conditions are linked: the short-term marginal cost determines the potential number of operating hours, which in turn determines the magnitude of the fixed costs allocated to each hour of operation, which is included in the long-term marginal costs. (Soysal, Sneum, Skytte, Olsen, & Sandberg, 2016)

Flexible operation of heat pumps and electric boilers can be limited by the dynamic operation capabilities of alternative heat sources such as biomass heat only boilers and CHP plants. In practice, unforeseen and rapid changes might not be possible with HPs and EBs without heat storage in the system, as heat production matching the heat demand must be ensured. The DH network itself can also act as a short-term heat storage allowing for short-term imbalance in heat production and consumption. If flexible capacity of EBs and HPs is optimised through day-ahead markets, it leaves time for DH operators to plan the next day's heat production corresponding to the DA

market results. Unforeseen and rapid changes could take place if the resources are offered to capacity markets with high ramping rates, such as aFRR and FCR. However, with aFRR and FCR-D, the participant can choose to offer either up- or downregulating capacity which in theory should ease the heat production planning and participation in the capacity markets. With heat storage, downregulation, meaning increase of demand in HPs or EBs, could in theory be always offered. In this case, biddable power and capacity is based on available HP and EB capacity, heat storage charging capacity, and heat storage level.

Figure 21 presents the short-term marginal heat production costs for four considered technologies on different electricity prices. In Figure 21, EBs and HPs are connected directly to the transmission grid, meaning the transmission grid tariff is used for the calculations to depict cost of electricity transmission. Figure 22 presents the marginal costs when EBs and HPs are connected to the distribution grid. A cost of 20 €/MWh is used for the distribution grid tariff similarly to AFRY (2021) to depict the approximate value in Finland. It should be noted that the distribution costs vary regionally. Technologies requiring high powers can be expected to be directly connected to the transmission grid. Additionally, technologies installed on e.g., CHP sites can utilise existing connections built for the power plants. Electricity can also be directly supplied by the CHP plant if its operating, in which case electricity use in heat pumps or electric boilers can be regarded as internal electricity use. In this case, costs of electricity tax and transmission do not have to be considered (Kontu, Rinne, & Junnila, 2019). The data used for the calculations is presented in Table 4. The lower taxation level of class II is used for the calculations. Fuel cost was calculated with a biomass price of 25 €/MWh. Nominal investment costs are not included in the marginal cost calculations, but they are presented to show the capital intensiveness of different technologies.

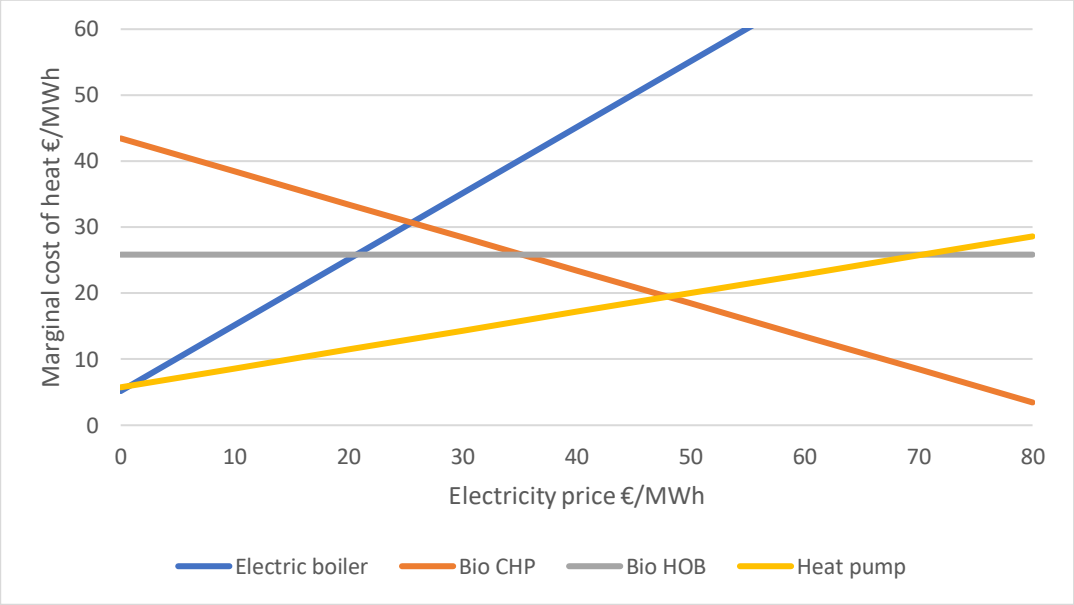


Figure 21: Short-term marginal cost of heat as a function of electricity price with a transmission grid tariff

With the transmission grid tariff at place, the marginal cost of heat from a biomass based heat-only boiler is lower than the cost of heat from EBs at an electricity price above 20,7 €/MWh. This crossing point can also be called the switching price of EBs. In case of heat pumps, the switching price is at around 48 €/MWh when the alternative heat source is a biomass based CHP plant. In case the alternative technology is a bio HOB, the switching price is at around 70,4 €/MWh. In the case with an average distribution grid tariff in place, the switching prices are significantly lower due to the higher starting marginal cost for electric boilers and heat pumps as presented in Figure 22. In this case, the switching price is for EBs is at 4,7 €/MWh. For HPs the switching price is at 14,5 €/MWh with a bio HOB alternative and 27,7 €/MWh for bio CHP plants.

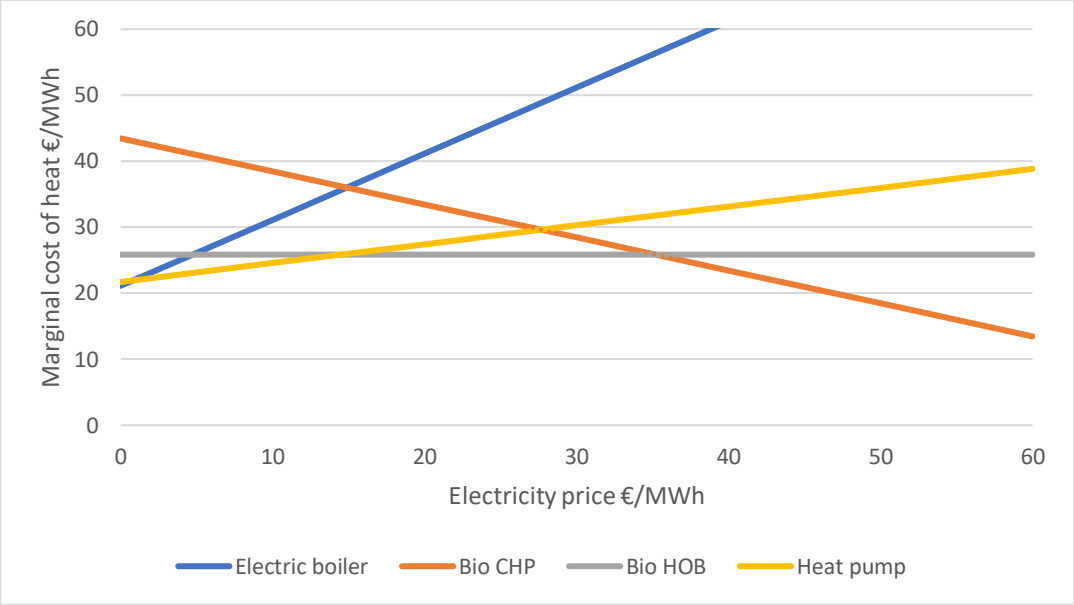


Figure 22: Short-term marginal cost of heat as a function of electricity price with a distribution grid tariff

Table 4: Data of considered district heating technologies (AFRY, 2021; Averfalk, Ingvarsson, Persson, Gong, & Werner, 2017; Danish Energy Agency, 2020; Soysal et. al., 2016)

	Electric boiler	**Biomass CHP**	**Biomass HOB**	**Heat pump**
Total efficiency	99 %	90 %	108 %	350 %
Heat efficiency	99 %	60 %	108 %	350 %
Electric efficiency		30 %		
Nominal investment (M€/MW_{heat})	0,07	1,05	0,57	0,86
Fuel cost (€/MWh_{heat})	Electricity	41,7	23,1	Electricity
Fuel tax/electricity tax (€/MWh_{elec})	0,63	-	-	-
CO2 cost (€/MWh_{heat})	-	-	-	-
Transmission grid tariff (€/MWh_{elec})	4,05	0,49	-	4,05
Distribution grid tariff (€/MWh_{elec})	20,00			20,00
Maintenance (variable O&M) (€/MWh_{heat})	0,50	1,30	2,70	1,7
Total marginal costs excluding electricity price (with transmission grid tariff)	5,18	43,46	25,85	5,75

4.1.4 Development and triggers

The development of the district heating sector is dependent on various factors. The magnitude of electrification in DH is highly dependent on the price developments of electricity and on the cost developments of competing technologies and new potential DH technologies, such as large-scale geothermal heat and small-modular nuclear reactors. The marginal costs of competing technologies have a high impact on the use of HPs and EBs as seen in Figure 21 and 22. For example, the addition of an energy tax to biomass would directly increase the marginal costs of biomass based heating, which would likely increase the operating hours of HPs and EBs in district heating networks (AFRY, 2021).

The development of the power production portfolio also has an impact on which investments are profitable on the consumption side. In the study of Kiviluoma and Meibom (2010) the impacts of demand side flexibility from power-to-heat and electric vehicles were analysed with a linear optimisation model including the Finnish power and district heating systems. The analysis was done with different shares of wind generation and with and without nuclear generation. Allowing the model to invest in new sources of flexibility in the energy system, such as power-to-heat and heat storages, increases the investments in inflexible forms of power production. In the study, the flexibility from the heating sector increases the market share of wind power more significantly than the flexibility from electric vehicles as the energy storage capacity of heat storages is much larger than the aggregated storage capacity from electric vehicles. One million plug-in electric vehicles were considered in the study. In terms of the captured average power price, heat pumps with heat storages benefit base load power production such as nuclear power relatively more than wind power as they require a more stable electricity source as capital intensive investments. Heat storages with electric boilers or electric vehicles benefitted variable generation more. In all scenarios, the average electricity price was lowest with both heating and electric vehicle flexibility measures in place.

Similar results are shown in the study of Schweiger et. al. (2017) which analyses the potential of power-to-heat in the Swedish DH system. The study considers only electric boilers as the technical potential of power-to-heat is estimated based on modelled negative residual load, meaning only surplus electricity is used for the operation of power-to-heat technologies. This results in low amount of operation hours which favours the use of EBs instead of HPs for the study. Installed capacity of electric boilers is set at 30% of the designed heat supply capacity. The study estimated the potential of power-to-heat in three scenarios with different production portfolios. The technical and economic potential of EBs grew with higher shares of VRE production as

the number of hours with negative residual load increased. In all scenarios, the access to thermal storages increased the potential of power-to-heat. In the study, the thermal storage is charged by the EBs during hours when the negative residual load is higher than DH heat demand. In the study of Kiviluoma and Meibom (2010), the heat storages are charged by EBs during very high wind power production. During periods of good wind power production, thermal storages actually discharge, as the storage is used in place of CHP plants which are less competitive in heat production during low price hours. During periods of lower wind, thermal storages can be charged by CHP plants and heat pumps with the overproduction available after meeting the heat demand. As a consequence, the optimal capacity of thermal storage is smaller in DH systems with less CHP capacity. It can be therefore argued that CHP capacity in DH systems also increases the potential and flexibility of power-to-heat due to the increase of optimal thermal storage capacity.

Industrial waste heat and waste incineration plants with low flexibility and marginal costs supply base load in the modelling of Schweiger et. al. (2017). This means that the heat demand covered by industrial waste heat and waste incineration cannot be supplied by power-to-heat. Consequently, a higher share of base load technologies such as waste incineration reduced the potential of power-to-heat. Additionally, in the sensitivity analysis, the potential of power-to-heat decreased significantly when the total annual demand of electricity was increased. Increase in electricity consumption outside the heating sector decreases the power residual available for power-to-heat.

The effect of grid tariffs, subsidies, and taxes on district heating production in the Nordics was studied by Sneum and Sandberg (2018). Electricity transmission and distribution grid tariffs vary in terms of design and magnitude among countries and regions but are typically constructed of a fixed component, an energy component, and a capacity component. In the study, the scenarios with energy component-based tariffs (ET) favoured the use of EBs. With capacity component-based tariffs (CT), savings coming from operating EBs for a few hours in a month during low electricity prices do not outweigh the costs of the increased monthly capacity charge. In Finland and Norway, capacity component-based tariffs lead to zero heat production from EBs in the study. It should be noted that a higher level of electricity taxation (22,5 €/MWh) was used for the study. Alternative tariff structures mentioned in the study that would encourage the use of electric boilers in district heating include energy component-based tariffs, time-of-use tariffs that change throughout the day, or lowering capacity tariffs and making them payable annually. A more ambitious option would be dynamic tariffs that carry signals from the power markets to power-to-heat.

4.2 Power-to-Hydrogen

This section starts by giving an overview of the main water electrolyser technologies. The overview is followed by an outlook of different pathways for hydrogen production through water electrolysis. Flexibility from power-to-hydrogen and influencing factors are discussed in chapter 4.2.3. The section concludes by discussing the development and triggers affecting the development of hydrogen production via electrolysis.

4.2.1 Technologies

Water electrolysers are electrochemical devices that split water molecules into hydrogen and oxygen with an electrical current. There are currently four main water electrolysis technologies: alkaline (AEL), proton exchange membrane (PEM), solid oxide (SOEC) and anion exchange membrane (AEM) electrolysis. The techno-economic characteristics of the electrolyser technologies are presented in Table 5. Alkaline electrolysers are the most mature technology. They have been used for hydrogen production in fertiliser and chlorine industries since the 1920s. Even large installations were installed in countries with large hydropower resources during the last decades, but they were for the most part decommissioned as the use of natural gas and SMR became mainstream. Compared to other electrolysis technologies AEL has low capital costs due to the absence of highly valuable materials. (IEA, 2019; IRENA, 2020)

PEM electrolysers were introduced in the 1960s to address some of the operational shortcomings of alkaline electrolysers. They employ pure water as an electrolyte solution, which eliminates the need for the recovery and recycling of the potassium hydroxide electrolyte solution, which is required with alkaline electrolysers. PEM electrolysers are able to produce highly compressed hydrogen without the need of an additional compressor, which makes coupling them with hydrogen storage easier. They can produce hydrogen at up to 30–60 bar without a compressor, as seen in Table 5. In some systems, the hydrogen output can even be at a level of 100–200 bars. PEM electrolysers are capable of very flexible operation. Their load range can vary from zero load up to 160 percent of design capacity, meaning that the electrolyser can be overloaded for a short period of time, typically around 10 minutes (Tractebel & Hinicio, 2017), if the plant and power electronics are configured appropriately. In the Energiepark Mainz pilot, the PEM electrolyser could operate 15 minutes at 150% load (Kopp et al., 2017). However, they require costly electrode catalysts - platinum and iridium – and membrane materials. Their lifetime is also currently shorter than that of alkaline electrolysers and are more expensive than alkaline electrolysers in

terms of overall cost. At the moment, they are less extensively used than alkaline electrolysers, but their use has been growing rapidly during the last decade. (IEA, 2019; IRENA, 2020)

One of the less developed electrolysis technologies is SOECs. They have not yet been commercialised, but they are currently being researched extensively and individual companies are now aiming to bring them to market. SOEC electrolysers operate at high temperatures and with good electrical efficiency. Due to the high operating temperature a heat source is required to produce steam for the electrolysis process. SOEC electrolysers can be used to co-electrolyse carbon dioxide and steam to produce a synthetic gas containing hydrogen and carbon monoxide, which is a valuable feature in synthetic fuel production (Buttler & Spliethoff, 2018). If the hydrogen produced is utilised to make synthetic gases or fuels, the waste heat from these exothermic synthesis processes such as Fischer-Tropsch synthesis or methanation could be recovered and used to generate steam for further SOEC electrolysis processes. Other major benefit of SOEC electrolysers is the possibility to operate them in reverse mode as a fuel cell. In fuel cell operation, hydrogen is used to produce electricity. With hydrogen storage, SOEC electrolysers could be used to provide grid balancing services, by alternating between electricity consumption and production as needed. (IEA, 2019)

AEM electrolysers are the latest water electrolysis technology, and they have not yet been commercialised. The potential of AEM is in the combination of more common and environmentally friendly materials from alkaline electrolysers and the simplicity and efficiency of a PEM electrolyser. It enables the use of commodity catalysts, titanium-free components, and, like PEM, differential pressure operation. The hydrogen production system design of AEM electrolysers is similar to that of AEM, but there are still uncertainties and challenges in high differential pressure operation, which allows for the greater load range similarly to PEM systems. (IRENA, 2020)

Table 5: Techno-economic data of electrolyser technologies in 2020 (IEA, 2019; IRENA, 2020; Tractebel & Hinicio, 2017)

	AEL	**PEM**	**AEM**	**SOEC**
Efficiency, LHV (%)	50–68	56–60	52–67	74–81
Operating pressure (bar)	1–30	1–60	1–35	1
Operating temperature (°C)	70–90	50–80	40–60	700–850
Load range (%)	15–100	5–160	5–100	30–125
Regulation ability (%/s)	0,2–20	100	-	-
Cold start, 0–100% load (min)	< 50	< 20	< 20	> 600
System capital costs, minimum 10 MW (€/kW)	440–880	615–1230	Unknown	2460–4920

Electrolyser system efficiency can be measured in units of kilowatt hours of electricity consumed per kilograms of hydrogen produced. As explained before one kilogram of hydrogen, measured in lower heating value, is equal to 33,3 kWh of energy. The efficiency of the electrolyser system is dependent on the electrolyser cell and stack efficiencies and the balance of plant losses. Rectifiers are a key element in the balance of plant. Rectifiers typically have low efficiencies at loads below 15–20% of the nominal load but they operate at relatively high efficiencies at higher loads. This can give an incentive to use the same rectifier for multiple electrolyser stacks to improve overall efficiency and decrease investment costs with fewer number of required rectifiers. As a drawback, the system becomes less flexible. With all technologies, multiple small modular stacks, each with its own rectifier, produce a more flexible electrolyser plant than a single large stack with a single rectifier. Other balance of plant elements, such as cooling, purifiers, thermal management and water treatment must also be factored into the overall efficiency of the electrolyser system. (IRENA, 2020)

Electrolyser systems have higher efficiencies at lower than nominal load, peaking at around 30%. After loads over 30% the overall system efficiency begins to decline toward the nominal value. It introduces a new attribute that can alter the operational strategy of the electrolyser. They can be run at part load to gain higher efficiency, resulting in lower electricity cost per unit of hydrogen, at the expense of decreased hydrogen output and lower total revenues. As a result, a trade-off between capital and operational costs should be considered (IRENA, 2020). As currently capital costs for electrolyser systems are at a high level, part load operation is less likely to be profitable. Part-load operation could allow for electrolysers to take part in FCR-N markets, where symmetrical up- and downregulation capability is necessary. For electrolysers that can operate at loads over their nominal, such as PEM electrolysers, this is also possible when operating at nominal load. For example, a PEM electrolyser that can operate at 160% load could offer 60% of its capacity to FCR-N markets. However, operating at maximum loads above the rated capacity requires the ensuring that all balance of plant equipment is capable of that maximum load, which can decrease the economic incentive. Additionally, the impact of overloading on long-term performance has yet to be researched (Buttler & Spliethoff, 2018). Participating in the FCR-N markets requires the electrolysers to be running to participate, which means that electricity for base load use needs to be purchased from e.g., the DA market (Kopp et al., 2017). In this case, the revenue from FCR-N markets can be considered as a cost-saving in electricity procurement for base load operation. Asymmetrical products for reserve markets are seen as a great tool to allow participation of electrolysers as they could offer unequal amounts of up- and downregulation (Tractebel &

Hinicio, 2017). In Finland, separate bids for up- and downregulation can be set for all reserves except FCR-N (Fingrid Oyj, 2021f).

Industrial scale alkaline electrolysers have been proven to be capable of providing regulation services at primary control reserve markets (Thyssenkrupp, 2020), which in Finland are the FCR markets. At operating temperature, the electrical input can be changed very quickly in both alkaline and PEM electrolysers. PEM electrolysers are a newer technology than AEL electrolysers and they have been developed keeping the flexibility requirements in mind. Alkaline electrolysers are currently undergoing development to improve their flexible operation. The dynamic operation capability of SOEC electrolysers is the worst of the four technologies due to the complex thermal management of the overall system, partly depicted by the cold start-up time, which is a result of the high operating temperature. The regulation ability of AEM and SOEC electrolysers is still uncertain. (Buttler & Spliethoff, 2018)

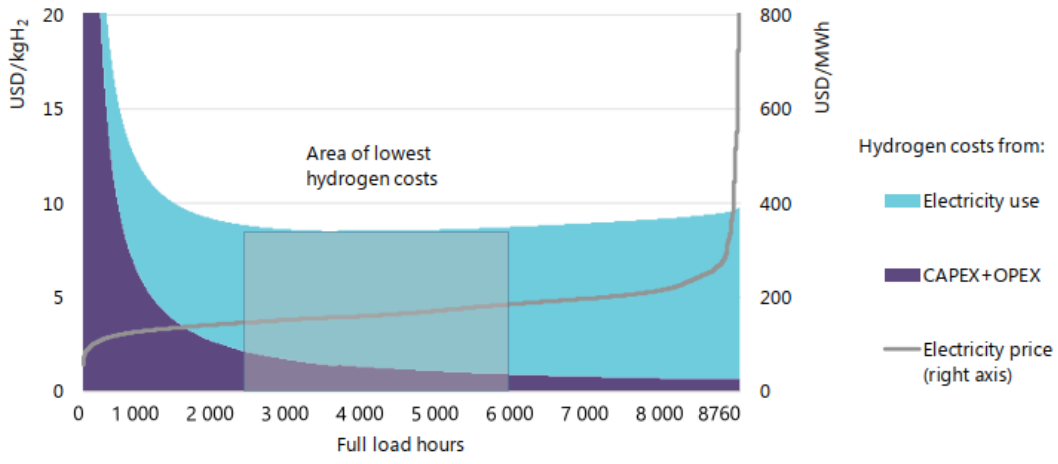
In a study done by Eichman, Harrison, and Peters (2014) on smaller scale PEM and AEL electrolysers, the electrolysers were found to respond to demand changes in milliseconds. For ramp-up and -down tests done for demand changes of 25, 50 and 75% of the load, it was found that both electrolysers had nearly settled the load changes in 0,2 seconds. Based on the response trajectories of the load changes, both technologies settled in less than one second for all test cases. According to the results, electrolysers could possibly offer fast frequency reserve (FFR) services as well. FFR in Finland is used for ensuring quick upregulation during low-inertia hours, as discussed in chapter 3. Technical requirements of reserve services in Finland are presented in Annex 1. It should be noted that the tests were done for smaller scale electrolysers (~40 kW), so their applicability to industrial scale electrolyser systems remains uncertain. Furthermore, the effects of variable electrolyser operation on electrolyser performance and lifetime can affect the possible business cases for flexible operation of electrolysers. (Eichman, Harrison, & Peters, 2014)

4.2.2 Hydrogen production pathways with water electrolysis

The costs of producing hydrogen from water electrolysis are impacted by a variety of technical and economic factors, the most important of which are capital expenses, system efficiency, electricity costs, and annual running hours. The marginal cost of production is mainly dependent on electricity price. Currently, electrolysers are a very capital-intensive technology, which means that high operating hours are required from the investment to recover costs. With high capital expenses, the levelized cost of produced hydrogen decreases with higher full-load hours as the capital costs are spread out for a

higher amount of produced units of hydrogen. Around 50% of the capital costs come from the electrolyser stack with alkaline and PEM electrolysers and the rest from balance of plant equipment. Capital expenses of electrolyser stacks are expected to decrease with increased production volumes, which can allow for lower operating hours in the future. (IEA, 2019)

The levelized cost of hydrogen (LCOH) production utilising grid electricity can be seen in Figure 23. The calculation is done with Japanese electricity spot prices for 2018 and with a capital cost of 800 USD/kW, LHV efficiency of 64% and a discount rate of 8%. The cost-optimal range of utilisation in full load hours in this case would be around 3000 to 6000 hours. In a similar example from Finland, the optimal range was between 4500 to 7800 hours. However, in this case, the cost assumptions were not specified (Forsman et al., 2021). With higher full load hours, the rising cost of electricity starts to increase the variable costs to such an extent that it is not sufficient to offset the benefit from spreading out the capital expenses. If a fixed price for the used electricity is assumed, the lowest LCOH is achieved with 8760 full load hours, as the operating costs are fixed, and the impact of high CAPEX is reduced with higher amount of full load hours. (IEA, 2019)



Notes: CAPEX = USD 800/kW_e; efficiency (LHV) = 64%; discount rate = 8%.

Source: IEA analysis based on Japanese electricity spot prices in 2018, JEPX (2019), *Intraday Market Trading Results 2018*.

Figure 23: Hydrogen costs from electrolysis using grid electricity (IEA. 2019)

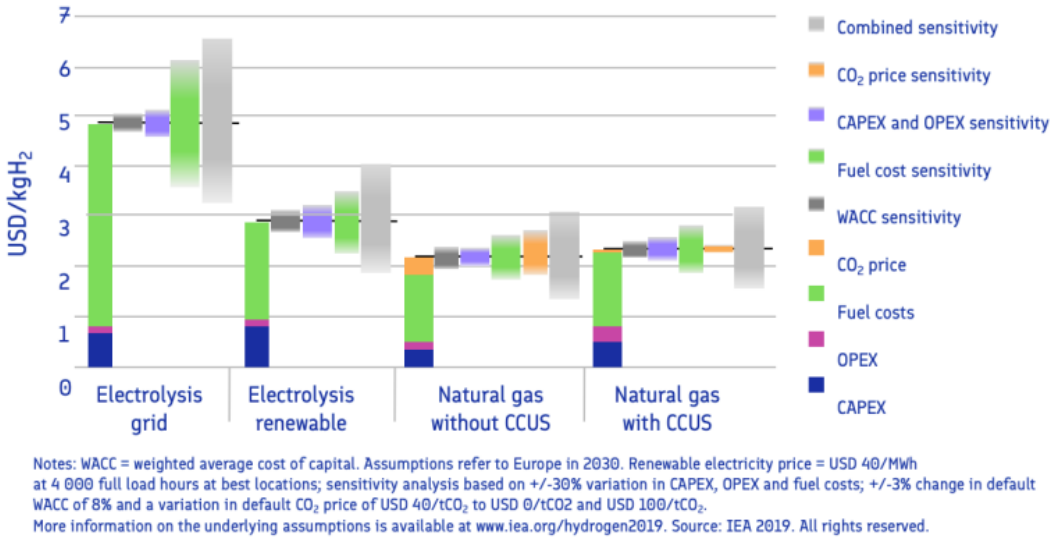
Dedicated energy generation from for example wind or solar provides an alternative to using grid electricity to produce hydrogen. Building electrolysers in places with high renewable production potential could become a low-cost supply alternative for hydrogen, even after accounting for the transmission and distribution costs of getting hydrogen from production sites to end consumers. With dedicated production and no connection to the grid, the electricity price can be essentially fixed and extra costs that occur from using grid electricity, such as the grid connection, transmission tariffs

and electricity taxes, can be avoided. However, the full load hours for facilities using a dedicated renewable source are low. For example, in Finland the capacity factor of wind power is on average 0,33 and at the highest 0,47 (Finnish Wind Power Association, 2022), which in terms of full load hours are equal to around 2900 and 4100, respectively. With low full load hours, the production costs remain high due to high capital expenses. The same principle is valid for grid-connected electrolysers that operate during low electricity price hours (IRENA, 2020). In the case of dedicated renewable production, the electrolyser sizing compared to the VRE production is a key factor when optimising the costs of the facility. To ensure high use at rated load for the electrolyser, the VRE production is oversized which enables a higher load factor for the electrolyser but results in curtailing some of the VRE production. With similar sizes for the VRE production and electrolyser, the electrolyser load factor is smaller, as variable sources such as wind rarely produce at nominal production power.

Due to the possible oversizing of the VRE production compared to the electrolyser, a large part of the potential VRE production needs to be curtailed in a fully off-grid setting. Therefore, a hybrid solution with dedicated renewable production and a grid connection could be the optimal setup in some cases. In this case, the excess VRE production can be fed into the grid. Additionally, it could be possible to use grid electricity to increase the operating hours of the electrolyser during low VRE production. Grid services could also be offered (eFuel Alliance, 2021). In this setting, it can be increasingly difficult to estimate the apparent production or load on the grid from VRE production or electrolysis facility.

Figure 24 shows the production costs of hydrogen with different production methods. As seen in the figure, the production cost of hydrogen is very sensitive to the price of electricity. The price through electrolysis should reach a price level of 1,5–3 USD per kilogram of hydrogen to be competitive against alternative production methods. With high prices of natural gas and emission allowances, hydrogen produced with renewables can already be cheaper than the production methods with natural gas (Collins, 2021). The assumptions behind the calculations are further explained in IEA (2019). In a calculation done by VTT (Laurikko et al., 2020), based on an overall CAPEX cost of 600 €/kW, 2020-2030 electricity price futures, transmission tariffs, and operation and maintenance costs, with 8000 full load hours, the cost of hydrogen would be around 2,5 €/kgH_2. With cost savings through spot market optimisation by reducing the most expensive 760 hours of the year and income from provision of FCR-D and aFRR reserves, waste heat and sales of oxygen, the resulting cost would be around 1.8 €/kgH_2. A profit of 20 €/ton of oxygen is assumed as well as a price of 20€/MWh of waste heat for 50% of the waste heat produced by the facility. A fixed income of 8,34

€/MWh is assumed from grid services. It should be noted that if there is a fixed demand for produced hydrogen, which can be the case in industrial uses, the electricity price optimisation and offering of grid services would require building a storage for produced hydrogen and oversizing the electrolyser, which is not to considered in the investment cost assumption of VTT. However, if only short-term flexibility that is based on temporarily overloading and ramping down the electrolyser is offered for example to FCR-markets, oversizing the electrolyser might not be necessary. For larger duration flexibility, oversizing is necessary, as the production lost during demand cuts has to be compensated by increasing hydrogen production during other periods.



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO2 and USD 100/tCO_2.
More information on the underlying assumptions is available at www.iea.org/hydrogen2019. Source: IEA 2019. All rights reserved.

Figure 24: Hydrogen production costs with different production methods in 2030 (IEA, 2019; Laurikko et al., 2020)

In an analysis done by Forsman et al. (2021), three alternatives for grid connected hydrogen production were studied: inflexible, flexible, and optimised. Inflexible electrolysers operate at rated power constantly, whereas flexible electrolysers can cut their demand during peak price hours by having an oversized electrolyser and hydrogen storage. In optimised operation, electrolysers use the hydrogen storage to optimise demand also during lower electricity price differences, picking the cheapest production hours available in the production window. The lowest electricity costs are achieved in optimised operation. Optimisation would not require significant additional investment for hydrogen producers compared to demand cutting during peak hours, as the hydrogen storage and oversized electrolyser capacity would have already been invested to avoid electricity peak hours.

The results of the study show that in 2030, the cost difference in LCOH between the inflexible and the optimised production is very low or non-

existent. The LCOH for the inflexible electrolyser in this case is 2,4–2,6 €/kgH_2 whereas for the optimised electrolyser with 12-hour storage it is between 2,3–2,5 €/kgH_2. In 2040, the benefit from optimisation is larger due to higher price volatility in the electricity market. It is assumed that in 2040, the share of variable generation is much higher due to increased capacity of renewable generation and decommissioning of nuclear power. LCOH with inflexible operation sits at 3,4–3,8 €/kgH_2 and at 3,0–3,3 €/kgH_2 by optimising production with the 12-hour storage. Additionally, according to the analysis of AFRY, for a grid-connected electrolyser facility operating in the Finnish market a hydrogen storage sized equivalent to 12 hours of demand would be a more cost-optimal size than a 24-hour storage size. With a smaller storage size, the benefits from electricity cost optimisation can already be achieved to a great extent. In 2030, the production cost of hydrogen grew with a 24-hour storage capacity compared to a case with 12-hour storage. In 2040, the production costs remained at a similar level. The results show that an additional investment to oversizing the electrolyser and building a larger hydrogen storage is not profitable solely based on cost savings from spot market optimisation. (Forsman et al., 2021)

In Germany pilot tests on procuring electricity for an industrial scale power-to-hydrogen plant were made. Three electricity procurement methods have been examined in the Energiepark Mainz project: purchasing electricity from the European Power Exchange, using surplus power from the associated wind farm, and participating in the secondary control reserve market. The load profile for the power-to-hydrogen plant was constant over each hour. When considering solely the costs of procuring electricity for the electrolysis, the participation in the secondary control reserve market was the most profitable option. In the study, the power-to-hydrogen plant receives money for using electricity, as it participates in downregulation markets. It should be noted that negative prices in downregulation are not common in Finland due to the large amount of hydropower in the Nordic system. An equivalent market in Finland would be the aFRR market. However, Finland currently only has a capacity market for aFRR, bids for balancing energy cannot yet be set. The study did not take into account the capital costs of the electrolysis facility, which have a major effect on the levelized cost of hydrogen. Solely by operating on the reserve markets, the operating hours of the facility are very low, which makes covering the capital expenses very difficult, as discussed previously. (Kopp et al., 2017)

4.2.3 Flexibility from Power-to-Hydrogen

Flexibility offered by facilities producing hydrogen or hydrogen and derived products is dependent on the system design. A system schematic of a hydrogen production facility with battery and hydrogen storage is presented

in Figure 25. The electrolyser technology has significant impact on the short-term flexibility capabilities due to different dynamic operation capabilities of electrolysers. However, balance of plant equipment, such as the mechanical compression of produced hydrogen, can also set restrictions to the dynamic operation capabilities of the system. Flexibility restrictions of mechanical compression can be avoided by storing the produced hydrogen at output pressure in a buffer tank before high pressure compression. The use of high-pressure electrolysers can be beneficial for this purpose to minimise the volume needs of the buffer tank. As with all technologies, the short-term flexibility can be ensured by installing an electrochemical storage before the electrolyser system. This can be beneficial especially in cases with direct connection to fluctuating power production such as wind and solar to ensure stable electricity input for the electrolyser. (IRENA, 2020)

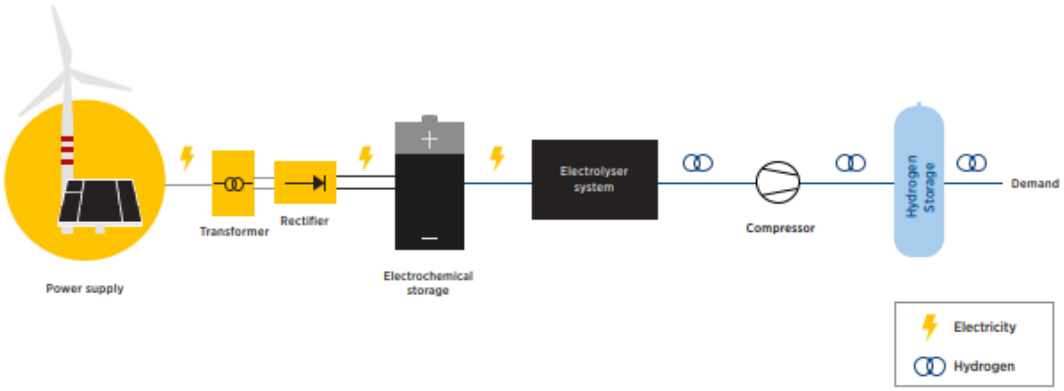


Figure 25: System schematic for hydrogen production facility with electricity and hydrogen storage (IRENA, 2020)

The end-use for the hydrogen and its characteristics set the limit for longer-term demand flexibility. For example, in the case of industrial use of hydrogen, the demand is seen as highly inflexible, as the industrial processes need to be run constantly to ensure competitiveness. If the demand of hydrogen is inflexible, long-term fluctuations of power supply can be decoupled from hydrogen demand by storing the produced hydrogen. However, this also requires increasing the size of the electrolyser to meet the hydrogen demand at all times, which increases the investment costs and peak loads of the system. Generally, hydrogen is stored in pressurised tanks or underground caverns. Underground hydrogen storage, such as salt caverns, is thought to be the most cost-efficient approach for storing hydrogen on a big scale (Laurikko et al., 2020; Hydrogen Cluster Finland, 2021). The duration the electrolyser system can offer demand flexibility is in this case directly linked to the size of the hydrogen storage.

A connection to hydrogen grid with sufficient capacity and storage can also enable long-term flexibility to electrolyser production as an alternative source of hydrogen is available through the pipelines. A hydrogen pipeline itself can act as a means of storage, as a small capacity of hydrogen can be stored in the pipeline. Blending of hydrogen to existing natural gas transmission grid is also a possibility. The hydrogen blending ratio in natural gas grids in Finland is limited to 1% due to customer requirements. As a larger scale example, a pure hydrogen pipeline connecting Finland to Central Europe would enable the use of the continents large-scale hydrogen storage potential as there are a significant amount of salt caverns and aquifers that could be turned into hydrogen storages. Hydrogen Cluster Finland (2021) is advocating for Finland to lead the effort in building a hydrogen pipeline to Continental Europe. In Finland there are no suitable geological formations for economical hydrogen storage, such as salt caverns. Lined rock caverns are seen as a cost-efficient alternative for medium-term daily or weekly storage (Laurikko et al., 2020).

The hydrogen produced by electrolysers is in gaseous form, typically ranging from ambient pressure to 30 bar, though greater pressures are possible. A smaller volume is required to enable cost-efficient hydrogen transport. This requires the use of compressors to pressurise the gas. The gas can also be liquefied or further refined to liquid fuels, such as ammonia. Going from ambient pressure to 70 bar, which is normal for transmission pipelines, can decrease gas volume by a ratio of 65. Compressing it to 1000 bar, a normal pressure for tank storage, can decrease volume by a factor of 625. Liquefaction can reduce volume by a factor of 870. Energy losses resulting from mechanical compression of hydrogen for different use-cases are presented in Figure 26. Compression losses in practice are a result of increased electricity consumption due to the mechanical compression of produced hydrogen, which leads to lower overall system efficiency. For example, the use of high-pressure tanks as storage can increase the electricity consumption of the system up to 16% (IRENA, 2020). Consequently, flexible production of hydrogen leads to higher investment costs due to the added expenses of investing in storage, compression facilities and oversizing the electrolysers, but it can also lead to higher operating costs due to higher overall electricity requirement. However, hydrogen storage enables optimising use of electricity to hours with lower electricity prices if the facility operation is optimised based on the market price.

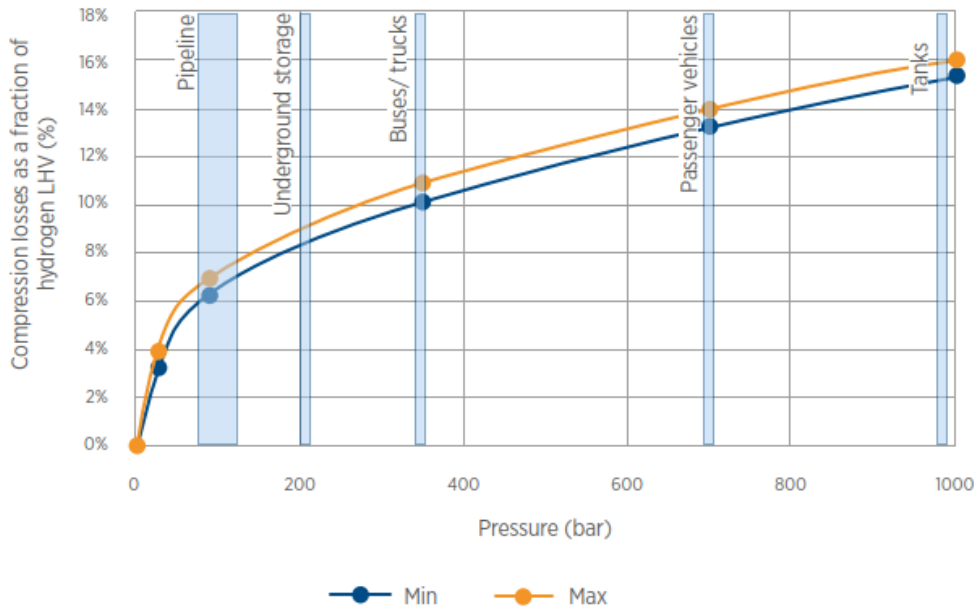


Figure 26: Energy losses for the multi-stage mechanical compression of hydrogen (IRENA, 2020)

4.2.4 Development and triggers

As the required capital investments for long-term storage and the oversizing of electrolysers are very high, the economic incentive can be to invest in short-term storage and offer flexibility via shorter term reserve markets such as FCR, or even FFR, if technically feasible. This allows for increased income from short-term reserve markets without a need for very large storages. From a system perspective, the greatest potential of power-to-hydrogen lies in long duration storage that can shift electricity demand of hydrogen facilities for longer durations and thus helping to ensure system adequacy and renewable integration. For short-term flexibility, existing solutions such as hydropower and batteries, are already able to support the system very effectively and could also quickly saturate the market of short time-scale reserves such as FFR and FCR. However, with a rapidly increasing share of wind power in the system, the demand for such services can increase. In the long term, integration with gas infrastructure such as salt caverns and pipeline systems can provide exceptionally large energy storage volumes to perform seasonal energy storage of renewable electricity in molecular form, thereby decoupling hydrogen demand and electricity demand of electrolysers from fluctuating renewable electricity production. In terms of volume, this is the source that can contribute the most to power system flexibility. The very rapid dynamic operation capabilities of various electrolyser technologies are not as important for such system service (IRENA, 2020).

The regulation on renewable fuels of non-biological origin will have a significant impact on the viable business cases for hydrogen production. Industry stakeholders are supporting the idea that at the first phase the requirement of additionality and geographical and timely correlation are not required as strictly as planned on the leaked drafts of the delegated act. It is suggested that there is a phase-in period, which allows for projects to deviate from the requirements during first stages, before they are made fully binding. The aim for the industry seems to be to ensure as high operating hours as possible for the electrolyser production. This supports the outlook provided in previous subchapters where the production pathways and costs of hydrogen production were discussed. In the scaling up phase, high operating hours could be ensured by enabling the use of grid electricity. Additionally, allowing the use of both low-emission electricity from dedicated VRE production and the grid can increase the operating hours when compared to only dedicated VRE production (Hydrogen Cluster Finland, 2021). The possibility of using nuclear power as a clean electricity source with guarantees of origins is also raised for discussion by E-fuel alliance (2021). As the costs of power-to-hydrogen facilities decrease the operating boundaries will also change when as high operating hours are not required to reach cost targets. This will consequently increase the potential of off-grid electrolysers with dedicated VRE production.

A major factor in the operation of hydrogen production facilities is the connection to the hydrogen grid and hydrogen storage. With connections to vast hydrogen markets through pipelines, the operation of electrolysers will change drastically. In this case, the cost of hydrogen production is not compared just to alternative technologies that are on-site, such as steam methane reforming from natural gas, or the cost savings achievable from storage and optimisation, but it is compared to the market price of hydrogen. The dynamics between hydrogen production, demand, levels of storage and transmission capacities will create their own system alongside the power system which needs to be understood and modelled to understand its effects on the power system and its operation.

In Finland, the location of hydrogen production can be largely influenced by the potential utilisation of electrolysis side-products and availability of CO_2. In Finland, several electrolyser projects moving into the feasibility stage have been published. They utilise CO_2 streams from existing district heating plants to produce synthetic methane with water electrolysis. The waste-heat from the power-to-gas plant is then further used in the district heating networks (Ren-Gas, 2022a; 2022b; 2022c). The sales of by-products can significantly increase the revenues of a power-to-gas facility, as previously discussed. In this case, electrolyser operation may also be limited due to the needs of the heating network. However, if synthetic methane is produced, it could

theoretically be blended into the natural gas grid as is, providing access to longer term storage. The operating conditions and limits of such power-to-gas plants should be further discussed with plant owners and operators to gain a better understanding of potential grid effects.

The operation of grid connected electrolysers is subject to grid tariffs. As with electric boilers in case of power-to-heat, capacity tariffs can steer investments towards less flexible operation. As flexible operation of electrolysers with fixed hydrogen demand requires oversizing the electrolyser, the facility is prone to higher capacity charges than one without a storage. The potential cost savings from flexible operation can be lower than the increased capacity charge resulting from higher peak loads. This means that as with EBs, electrolysers can be discouraged to operate according to the systems needs by a capacity payment based grid tariff structure.

4.3 Power-to-Heat in industry

As seen in Figure 5 and previously discussed, industrial heat production in Finland is already largely based on carbon neutral sources. However, due to the large energy needs of industry, the potential for electrification is still significant. If the use of fossil fuels in industrial heating processes is phased out, 10 TWh of heat needs to be produced by different technologies, in which electrification can have a significant role. The potential is further increased if electricity is used to replace biomass. However, for technologies with high level of technological readiness, such as compression heat pumps, the potential is limited by the viable output temperatures. For heat pumps, the largest potential lies in use at low temperature levels, as it allows for a higher COP, as discussed in the case of district heating utilisation. From the viewpoint of electrification, low temperatures are interesting due to technologically ready solutions but also due to the capability to offer flexibility via utilisation of heat storages, which are already highly developed for the low-temperature range. (Munster et. al., 2020)

In the research of Naegler, Simon, Klein, and Gils (2015), industrial heat demand was estimated and shared for different temperature levels for all 28 European Union member states. For Finland, the share of industry heat need below 100 degrees was estimated to be 25%, of which 10% came from space heating and hot water. Share of process heat at temperature range between 100 and 500 degrees Celsius was almost 50%, a similar figure to that of Sweden. This is due to the relatively high share of paper, pulp and print industry in Finland and Sweden. Across Europe, the share of low temperature heat is similar to the estimates of Finland, with around a quarter of heating needs being below 100°C. However, in Europe as a whole, heat at

very high temperatures, meaning over 400 to 500°C, is more than 50% of all industry heat consumption.

The largest energy consuming industries in Finland are the forest, chemical and metal processing industries. As seen in Figure 27 for the case of Germany in 2006, the process heat temperature needs vary a lot between different industries. For the metal processing industry, the required temperatures are very high. For the chemical industry, a mix of different process heat temperatures are needed with roughly 20% of heating needs being below 100°C. In the low-carbon roadmap of the chemical industry, 35% of heating needs were estimated to be below 200°C (Pöyry, 2020a). In the forest industry, temperatures over 500°C are not required and a large share of heating needs are below 100°C. In terms of energy consumption, the largest potential for electrification lies in the most energy intensive sectors. However, as seen in Figure 27, the potential for example in food industry is significant due to the relatively large need of low-temperature process heat (Naegler et al., 2015). In Finland, the food industry is the 4th largest industrial energy consumer. In Finland however, 80% of the energy requirements of the food industry are already covered by electricity based technologies and purchased heat (OSF, 2022a).

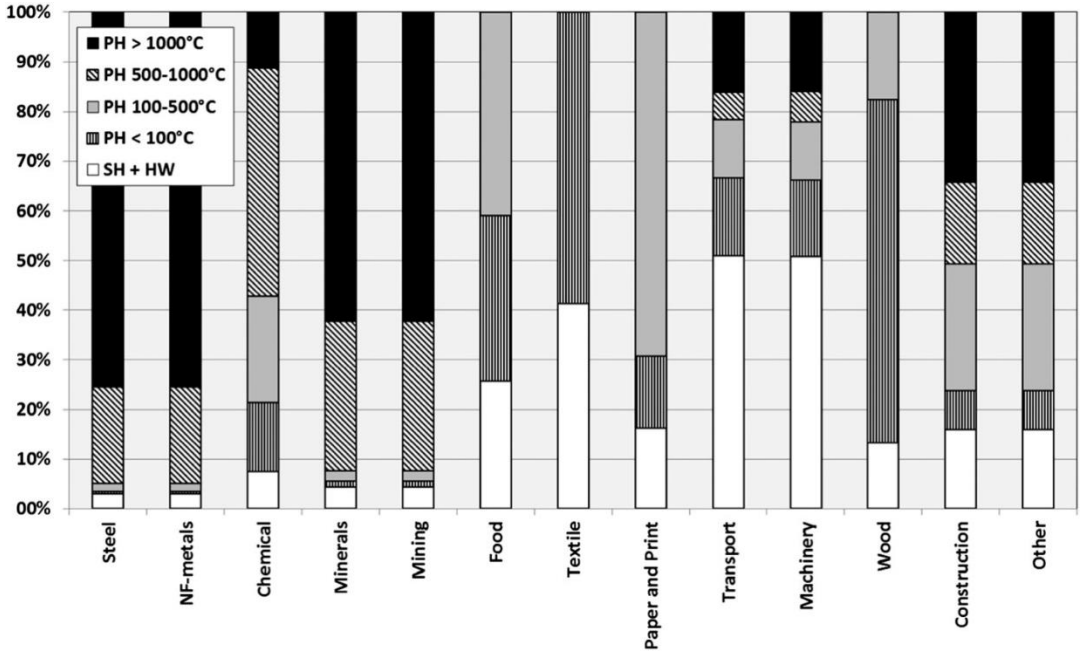


Figure 27: Estimates of the share of space heat and hot water and process heat at different temperature levels for different industries in Germany in 2006 (Naegler et al., 2020)

Heating technologies can be divided to two categories, direct and indirect heating. In indirect heating, a heating medium such as water or air is heated and used to transfer heat to the object. With direct heating technologies the

object is heated by initiating heat-generating reactions inside the material, for example by means of infrared or microwaves. Indirect heating technologies such as heat pumps and electric boilers can allow for the utilisation of existing heat transfer infrastructure and enables storing heat in the heat transfer medium. Direct heating technologies can be more difficult to integrate in the existing industrial heating processes as with direct electrification the possibility of integrating heat flows of different processes is lost. However, the total process efficiency can be boosted due to more targeted heating. Direct heating technologies can provide flexibility by e.g., changes in production rate. The feasibility depends on the industrial sector and process. The possibility of using an alternative heating source will also enhance the flexibility of heat production, similarly to district heating. An overview of industrial electricity-based heating technologies is presented in appendix C. (Munster et. al., 2020)

As the electricity-based technologies in industrial heating are at an early stage of deployment, especially at high temperatures, the development is very uncertain. The best estimate of the development in different industrial sectors is likely presented in the low-carbon roadmaps prepared by the industries. For the three most energy intensive industries, the largest development in electrification is seen in the chemical industry. By 2035, electrification of process heat and fuel switches are estimated to increase electricity consumption by approximately 7 terawatt hours in the low-carbon scenario. The current electricity consumption of the chemical industry is 7 TWh. In metal processing the increase in electricity consumption is estimated to be roughly 5 TWh. In the fast development scenario, the consumption is increased due to natural gas being partly replaced by electric furnaces in metal processing outside the steel sector. In the low-carbon scenario, named forced emission reduction scenario, natural gas is replaced fully by biogas and the increase in electricity consumption stems from carbon capture and storage. In the forest industry, electrification of process heating is seen to grow electricity consumption very little. (Pöyry, 2020a, 2020b, 2020c)

As in district heating, the development of electrification in process heating is very much influenced by the cost development of fossil and biomass based heating. In Finland, the largest energy source for industrial process heating in the forest industry is biomass waste and other wood fuels. Increase in energy taxation of biomass can have a significant impact on heating electrification. For fossil fuels, the fuel cost and the cost of emission rights have a large impact on heating costs. In the long run, power-to-heat in industry can become a significant consumer of electricity but also a major provider of flexibility to the power system. In industry, heat demand and heating processes are much more predictable and therefore easier to control

than in district heating. Furthermore, in industry, there is no strong seasonal variation in heat demand due to outside temperature changes which means that the electricity demand, and potential flexible demand, is high throughout the year. Flexibility potential can be further enhanced with the use of heat storages.

5 Modelling of demand flexibility

Chapter 5.1 introduces the power market modelling software used at Fingrid and in the thesis. Chapter 5.2 presents an overview of the current modelling methods for district heating heat pumps and electric boilers and electrolysers and discusses the weak points of current methods. In chapter 5.3, new methods for demand flexibility modelling are discussed and new demand profiles are developed for district heating heat pumps and electric boilers for one case year. Modelling cases used in the analysis of the thesis are also presented. Due to high uncertainties, power-to-heat in industry is not discussed in this or later chapters in the thesis.

5.1 Power market modelling software

For power market simulations, Fingrid uses BID3, a power market simulator developed by AFRY. BID3 is a dispatch model used to simulate supply and demand for all hours, minimising the system cost of meeting the power demand for each hour. The dispatch model calculates one electricity price per hour based on perfect foresight planning and optimisation of generation and demand. This means that balancing happening via intraday or reserve markets is not modelled separately and prices for ID or reserve activations are not set. On the generation side, the model takes into account the dynamic constraints of dispatchable generation and simulates variable renewable generation based on historical weather data. In BID3, stochastic modelling for hydro power is used to determine the option value for stored hydro power. Market areas are represented as separate nodes that are connected to each other with interconnectors. Each node in the model represents the situation in the market area in terms of installed production capacity, demand, and meteorological data. The Autobuild module of BID3 can also be used in scenario building to assist in evaluating investments in power generation, consumption, and transmission. (AFRY, 2022)

Power market simulations can be utilised for example for short-term market forecasting, asset evaluation, and long-term scenario analysis. Fingrid utilises power market simulations mainly for long-term scenario analysis and investment planning. However, as the system is changing rapidly due to increasing shares of VRE, the need for assessing upcoming system changes has increased. Scenario building and power market simulations can be utilised to estimate what the system looks like in the future and the market results can be used to the analyse the effects on power system operation. Currently market modelling is used as a tool for strategic grid planning, where the focus is on ensuring sufficient transmission capacity for future needs. However, to assess system operation challenges, the market modelling

needs to be developed to also depict the operation of new energy resources more accurately.

5.2 Current modelling methods

In BID3, there are three main ways to model demand flexibility: demand cutting, demand shifting and demand optimisation with storage. The methods are presented in table 6. Demand cutting decreases the annual consumption of electricity. Consumption is decreased based on a set price threshold, which can depict for example the opportunity cost of alternative technologies to produce heat or hydrogen. With demand shifting the consumption is shifted to the following or previous hours. If all of the shifted demand has to be recovered and met during the following or previous hours, the annual electricity consumption remains unchanged. If there is an alternative technology to meet the demand, such as a heat only boiler, all of the shifted demand does not have to be recovered. Demand optimisation with storage optimises the electricity consumption to the lowest price hours based on the costs of storage utilisation and constraints set by the storage size.

Table 6: Modelling demand flexibility in BID3

	Reason for activation	**Relevant parameters**	**Annual demand**
Demand cutting	Activated based on threshold price which reflects the cost of demand reduction based on, for example, the marginal cost of alternative heating technology.	- Threshold price - Percentage of demand reduction - Min. and max. duration of demand reduction	Demand cutting decreases annual demand
Demand shifting	Activated based on threshold price which reflects the cost of demand reduction. The cost is compared to the price difference between market hours.	- Threshold price - Percentage of demand reduction - Min. and max. duration of demand reduction - Amount of energy recovered after demand cut - Recovery duration	If 100% energy recovered, annual demand unchanged. If 100% not recovered, decreases annual demand.
Demand optimisation with storage	Demand optimised based on costs and savings from storage use.	- Storage size - Charging losses - Storage losses	Annual demand unchanged

5.2.1 Power-to-Heat in district heating

Electricity demand in BID3 is modelled by allocating annual electricity demand to different demand groups. For each demand group, a demand profile that depicts the load profile of the electricity demand for all hours of the modelled years is determined. Demand profiles allocate the annual demand for each hour by a weighted value. If the value is 1, the hourly demand for all hours of the year is equivalent. Values over 1 mean a higher value than average hourly demand and values below 1 a lower demand. If the average value of the demand profile is 1, the annual input demand is equivalent to annual end demand. Demand profiles can vary between years for example according to weather patterns.

The district heating system is not modelled separately, which means that district heating demand or district heating production is not assessed by the model. Additionally, district heating production capacities are not analysed before or during the modelling. No limitations for production capacities for power-to-heat are set, meaning that they are determined by the allocated annual electricity demand and the demand profiles of the demand groups. Currently in Fingrid, electricity use in district heating is modelled with same demand profiles as electricity use in residential heating. The demand profiles are based on the weather dependency of electricity use in residential heating.

Values for the demand profiles are on a daily resolution. The demand profiles have hourly values, but values inside each day are similar. Using daily values means that the highest weather extremes are averaged out during the day. As a result, the highest peaks, and lowest valleys in electricity demand for heating are not depicted in the modelling with daily values. It should be noted that district heating systems contain significant amount of thermal inertia in the DH network which itself can help in alleviating the peaks. Demand profiles currently used for electricity consumption of district heating are presented in Figure 28. Annual allocated electricity demand and demand profiles set the input demand used by the model, which then turns into actual electricity demand based on the demand flexibility settings.

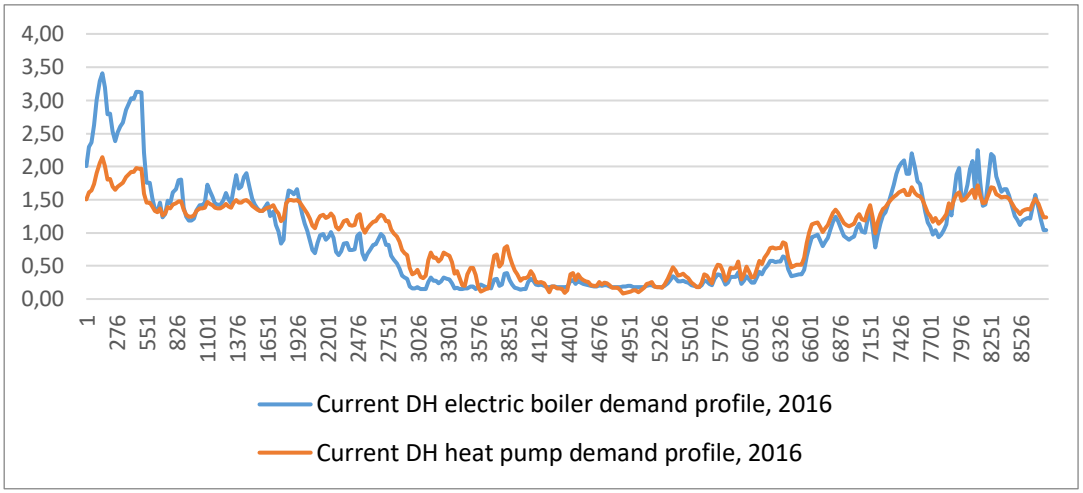


Figure 28: Currently used demand profiles in modelling for electric boilers and heat pumps for the year 2016

As discussed in chapter 4, heat pumps in district heating systems are largely used for base- or mid-load operation. This means that their electricity consumption should not follow the temperature changes as strongly as they do in the current modelling method. With current demand profiles, the demand is likely overestimated for certain periods which consequently overestimates the capacity available for flexible demand. Also, the demand at times can be underestimated, as the demand might not follow the temperature changes as strongly when the heat demand is high enough for base load operation to run at full capacity.

Fingrid's estimate of annual demand for electricity in district heat production is 8,7 TWh in 2035. The number is based on an estimate of how much electricity would be needed to replace fossil fuels in district heating production. The estimate differs significantly from those of AFRY (2020), where 2 TWh of electricity use in DH was estimated in the low-carbon scenario and 3 TWh in the business-as-usual scenario in 2035. The estimate is kept as is in the thesis but the assumptions behind it should be carefully assessed in further studies to not overestimate the electricity consumption in DH. It should be noted, however, that it is common to utilise high estimates in the market modelling process and strategic grid planning in order to ensure that future transmission capacity need estimates are done with the worst-case scenarios. Currently, half of the estimated demand of electricity for DH is allocated to electric boilers and half for heat pumps. Based on the literature review, this results in a very high estimate of electricity consumption in DH EBs, as they are typically used for very few hours during the year during low electricity price hours or for peak production. Electricity demand for district heating EBs and HPs is added on top of the demand for residential electric heating and residential heat pumps, as they use the same demand profiles. Separating the district heating electricity consumption and

further separating them to EBs and HPs would make assessing flexible operation of individual technologies and demand groups easier.

The demand flexibility for district heating electric boilers and heat pumps is modelled as demand cutting. A price threshold of 75 €/MWh is used for demand cutting, which is based on the alternative price of heat production with biomass heat only boilers. It is assumed that the marginal price of heat from biomass HOBs is 25 €/MWh. Therefore, in DH HPs with a COP of 3, demand should be cut at a price of 75 €/MWh. In contrast to the findings in chapter 4 and figures Figure 21 and Figure 22, the same price threshold is used for heat pumps and electric boilers. This does not accurately depict the marginal heat production costs of EBs and HPs and can significantly overestimate the electricity demand in DH EBs.

5.2.2 Power-to-Hydrogen

To model the demand and production of hydrogen, separate market areas are used in the modelling. For the hydrogen areas, demand for hydrogen can be determined for different demand groups similarly to electricity demand in the electricity market areas. Demand in the areas is technically electricity demand in the modelling, but it represents hydrogen demand in the modelling. Currently, Fingrid uses one hydrogen demand group with fixed demand in all areas to depict all hydrogen demand in Finland. For Central Europe, a seasonal hydrogen demand group is also utilised to depict the seasonality of hydrogen demand in e.g., space heating. With fixed demand, the annual demand for hydrogen is spread out evenly to all hours of the year, meaning a demand profile value of 1 for all hours. This is in line with the views of the energy intensive industries utilising hydrogen in their production facilities. Halting production to allow for a flexible demand of hydrogen is not a viable solution for the competitiveness of an industrial operator.

In the modelling at Fingrid, hydrogen production in the hydrogen areas can be done with steam methane reforming with carbon capture and storage or with alkaline electrolysis. Electrolysers are modelled as interconnectors between the electricity and hydrogen areas therefore matching the demand of hydrogen in the hydrogen areas and creating a demand for electricity in the electricity areas. A loss of 30% is set for the interconnectors, depicting an efficiency of 70% for the electrolysers. Hydrogen storage can also be modelled in the hydrogen areas by adding storage capacity, which in the hydrogen areas represents, for example, storing hydrogen in pressurised tank storages or in salt or lined rock cavern storages. Transmission capacities between hydrogen areas can also be changed to model hydrogen pipelines between the areas. No transmission constraints take place inside the

hydrogen areas, similarly to the electricity areas. With fixed hydrogen demand, the flexibility of electrolysis is therefore dependent on the size of the storage and access to alternative sources of hydrogen, in this case production through SMR with CCS or the import of hydrogen from other hydrogen areas.

According to Leao (2020), modelling through separate areas is more suitable for hydrogen production when compared to modelling as flexible demand with storage, as it allows the utilisation of storage on a seasonal basis. Seasonal storage, for example in salt caverns, would improve the flexibility of hydrogen production and is likely to be used in a scenario with a developed hydrogen economy because both electricity consumption and renewable energy generation can be unevenly distributed throughout the year. Furthermore, modelling with separate areas allows for assessing the viability and impacts of hydrogen pipelines. In the modelling, salt caverns are used for seasonal storage in Central Europe.

5.3 New methods to model flexible resources

This chapter points out the areas of development in current modelling. Some of the identified areas of development will be addressed as written reflection and lifted as recommendations for further studies and some will be included in the analysis carried out with market modelling. Modelling cases used for analysing electricity use in district heating and hydrogen production in chapter 6 are presented.

5.3.1 Power-to-Heat in district heating

The first step to improve the modelling of Power-to-Heat in district heating is to separate the electricity consumption in district heating electric boilers and heat pumps from the electricity consumption in residential heating. Even though they follow the same demand profiles, the demand flexibility parameterisation is different for district and residential heating technologies. To better assess where the demand flexibility happens, the demand should be separated to different demand groups.

To further develop the modelling with the current modelling methodology, improved demand profiles for DH EBs and HPs should be developed to better depict the operation of heat pumps in base- to mid-load heat production and the use of EBs in peak production. In this thesis, demand profiles for DH EBs and HPs were constructed from district heating production data of Helen (2022a). The data contains hourly district heating production in the district heating network of Helsinki for the years 2015–2020. The data is used to construct a district heat demand profile for Finland for the year 2016. Year 2016 is chosen a case year for the analysis as it is the year with the highest

peak demand during the analysed period and therefore can be used to depict impacts on power system operation during weather extremes.

With the Helen data, a demand profile for district heating demand for the case year can be constructed. First, a daily demand profile for district heating demand for Helsinki is done by dividing the hourly DH production values with the yearly average. Second, the hourly values for each day are summed together and divided by 24 hours to gain daily average values. Identical daily average values are used for all hours inside the same day, similarly to current demand profiles based on residential heating. Hourly values could be constructed as well from the data, but daily values are used to stay comparable to current methods. Third, the demand profile values are used to estimate the annual district heating consumption of 2016 (33,2 TWh) in Finland by multiplying the average hourly district heating heat demand in 2016 with the values gained in step 2. The resulting hourly demand and demand profile values are presented in Figure 29.

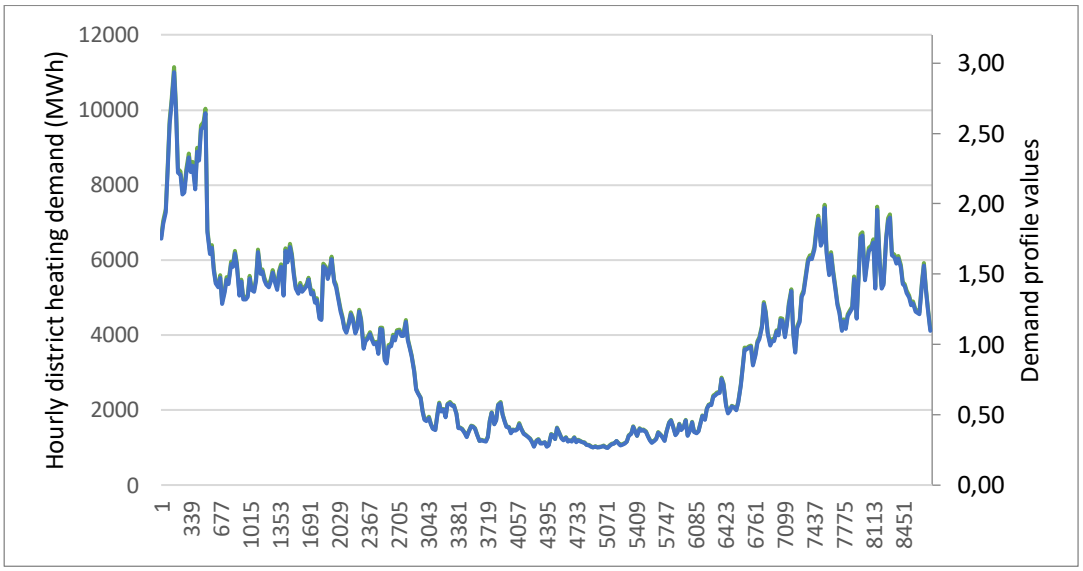


Figure 29: Hourly district heating demand in Finland and demand profile values for the year 2016

The method gives a rough assumption on hourly district heating demand in Finland, which can be utilised to further develop the demand profiles for EBs and HPs. The method could be further developed to take into account the weather patterns in regions outside of Helsinki as well for example by assessing the temperature dependency of DH demand in Helsinki. Similar profiles for other regions could be constructed by using local weather data and temperature dependency from Helen's case. It should be noted that temperature and DH demand correlation can differ in different DH systems. However, the current demand profiles that are based on residential heating

use the same values in all regions of Finland as well, meaning the weather dependency is not taken into account with high geographical accuracy.

To better depict the use of heat pumps in base load operation, an operating range is given to the heat pumps. In the chosen method, DH HPs operate at maximum load when the hourly heat demand is at or above the yearly average, which in this case is equivalent to roughly 3800 MWh. Below that threshold, the electricity demand of HPs follows the district heating demand. It should be noted that only the heating use of DH heat pumps is considered in this thesis. Furthermore, electric boilers are set to operate as peak load producing units. In this case, the heat load covered by base load technologies is not allocated to electric boilers, as it is assumed that there is no incentive to replace the heat load covered by heat pumps or other base load technologies with electric boilers. This means that when heat demand is below 3800 MWh, there is no heat demand and subsequently no electricity demand allocated to EBs. When the heat demand exceeds the demand allocated for base-load technologies, the electricity demand of EBs follows the heat demand. Heat and electricity demand allocated to EBs is therefore the heat demand that is already not covered by base load technologies. The heat demand allocation is presented in Figure 30. The resulting demand profiles for the case year of 2016 are presented in Figure 31.

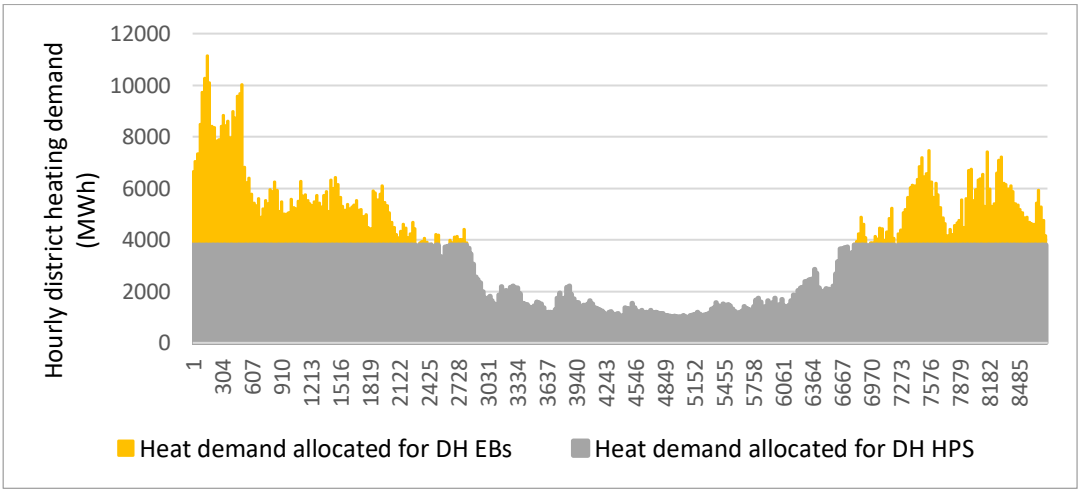


Figure 30: Heat demand allocation for district heating heat pumps and electric boilers

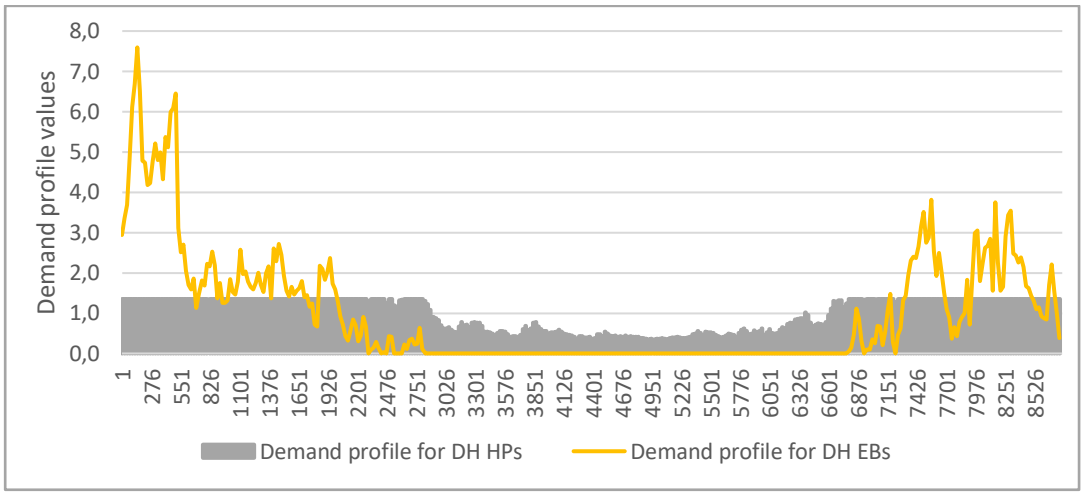


Figure 31: Demand profile values used for modelling electricity demand of district heating heat pumps and electric boilers

The profiles were developed with the operational behaviour of DH technologies in mind but were also developed so that the maximum power levels of EBs and HPs do not differ significantly from the current modelling method. Too high of a difference between modelling methods could lead to a situation where the comparison of different scenarios is not valid as is but would require altering the scenarios in terms of e.g., power generation capacities. To reach similarity, 75% of the annual demand of electricity for the DH sector was allocated to DH heat pumps and 25% to electric boilers. If a 50/50 allocation was used as in current modelling, the electricity demand of EBs would at times be very high, in practice requiring a significant amount of installed EB capacity and increasing the potential peak power requirement of the DH sector drastically. The 75/25 allocation can also be argued based on the literature review, as HPs are used for high full-load hours in base-to mid-load operation and EBs in peak production. The aggregated input electricity demand from DH HPs and EBs with both the currently used modelling method and with the new demand profiles and 75/25 allocation is presented Figure 32. The demand with new demand profiles and 50/50 demand allocation is presented in appendix D. The developed demand profiles seem to better depict the operational behaviour of district heating heat pumps and electric boilers discussed in chapter 4, without drastically changing the electricity consumption of the DH sector. This allows for the flexibility parameterisation of HPs and EBs to be separated and better depicts the hourly flexible capacity per technology.

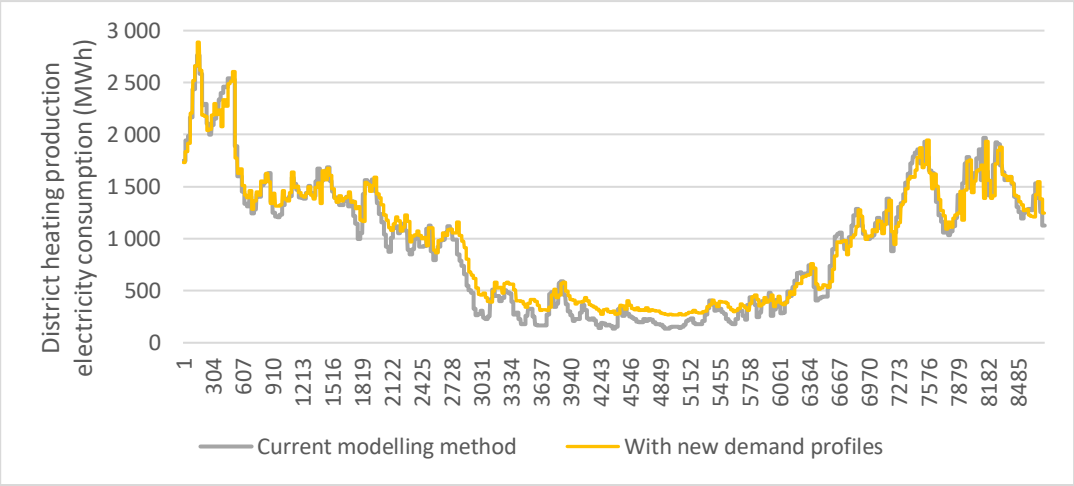


Figure 32: District heating electricity consumption in 2016 (input demand) with the current modelling method and with new demand profiles and 75/25 demand allocation

To analyse the impacts of district heating electrification on power system operation, three different pathways of heating electrifications with different flexibility parameters were used. The current modelling method and the modelling method with the newly developed demand profiles were used as base cases. The parameterisation for all modelled cases is explained in brief in Table 7. For cases 2–4, new demand profiles from case 1 are used for DH HPs and EBs.

Table 7: Demand flexibility parameterisation for analysed cases

Case	Demand allocation	Flexibility enabler	Flexibility percentage	Price threshold for flexibility
Base case	50% HPs 50% EBs	Alternative heat source (biomass HOB)	HPs: 60% EBs: 60%	HPs: 75 €/MWh EBs: 75 €/MWh
1) New demand profiles	75% HPs 25% EBs	Alternative heat source (biomass HOB)	HPs: 60% EBs: 60%	HPs: 75 €/MWh EBs: 75 €/MWh
2) Highly flexible	75% HPs 25% EBs	Alternative heat source (biomass HOB)	HPs: 80% EBs: 100%	HPs: 71 €/MWh EBs: 21 €/MWh
3) Fixed	75% HPs 25% EBs	-	HPs: - EBs: -	HPs: - EBs: -
4) EBs with heat storage	75% HPs 25% EBs	HPs: alternative heat source (biomass HOB) EBs: heat storage	HPs: 60% EBs: 100%	HPs: 75 €/MWh EBs: optimised

District heating modelling is not done at Fingrid, which means rough assumptions need to be made to depict different development paths of district heating electrification. Cases are also made drastically different on

purpose to emphasise the impacts of different pathways. District heating production capacities are not used as input in the modelling or used as basis for determining DH electricity demand inputs. To assess the development of DH production capacities, modelling and scenario building for the sector should be done as well. For example, in the highly flexible case (case 2), the flexibility is based on an alternative heat source, which in this case is biomass HOB. From the DH system perspective, the assumption can be considered as weak as it would require the oversizing of DH production capacity as during all hours HP and EB heat production can be switched to biomass HOB production. In reality, there might not always be an alternative heat production method available if the DH production capacity in the system is limited to be sufficient for peak demand, which would mean that HP and EB production could not be halted during peak hours. The alternative heat production technology can also differ based on the DH system and the heat demand level. For example, at mid-load, it is more likely that production from biomass HOBs can be increased than during peak loads.

In the fixed case (case 3), no flexibility is given to DH HPs and EBs. New demand profiles are used for the modelling. The case can be considered quite unrealistic it assumes that heat is produced with EBs and HPs at any cost of electricity. This would mean that no alternative heat production technologies are available at any time and that no heat storages are built. With the high seasonal difference of heat demand, it should be safely assumed that an alternative heat source is available during some times of the year at least. Also, with increasingly volatile electricity prices, investments into heat storages are seen to increase. However, in this thesis, case 3 can be used to depict the challenges caused by inflexible heat production and it works well as a comparison case to the more flexible cases.

In case 4, a heat storage is added in connection to DH EBs. A simplified method to model heat storages is used. In this case, the electricity demand of DH EBs is modelled as flexible demand that can be optimised with storage. Therefore, HPs cannot utilise the same storage to optimise their electricity consumption, as they cannot be connected to the same storage. For HPs, similar flexibility parameters are used as in the base case. A storage capacity equal to 24 hours of peak EB electricity demand is used for the modelling. Peak capacity for EBs in the modelling is 1885 MW which leads to a heat storage capacity of 45,2 GWh. The storage size is based on a compromise between the assumptions used in the analyses of Forsman et al. (2021) and Joronen et al. (2021). In the study Forsman et al., a heat storage with 8 hours of storage capacity was assumed. In the non-combustion based scenario in the study of Joronen et al., the expected heat storage capacity need is equal to roughly 44 hours of peak heat demand. The 24-hour storage size is seen as feasible for this thesis, as it provides a sufficient level of opportunity to

concentrate EB electricity consumption on low-cost hours, avoiding price peaks and potentially alleviating system impacts.

Based on even currently existing heat storages and published projects the estimated storage size can be argued to be conservative. Helen in Helsinki has a heat storage capacity equal around 18 GWh when considering existing and planned projects (Helsinki Energy Challenge, 2020). The district heating company in Vantaa has plans to build a heat storage with a capacity of 90 GWh (Vantaa Energy, 2021). However, as the heat storages are not utilised solely for EB optimisation and short-term heat production optimisation, their capacity cannot be fully dedicated to EBs. Furthermore, as stated in the study of Leao (2020), the modelling method where storages are modelled in parallel to flexible demand is not suitable for modelling long-term seasonal storage, which is common in the DH sector. This is also one of the benefits of sector integration between the electricity and DH sector. In the modelling used in the power market simulation, the flexible demand storage unit is optimised in 10-day optimisation windows. Heat storage losses are not considered in the modelling.

Storage can be also modelled in a simplified manner by allowing demand to be shifted from one hour to another, as explained in chapter 5.2. This modelling method is used to model the flexibility in residential heating. In this case, the building itself is acting as a heat storage. This method was also tested in this thesis to model DH heat storages. However, with this modelling method, no restrictions are considered for maximum heating capacity. For example, with 100% demand shift and 100% energy recovery, the electricity demand for EBs doubled after the hours when demand was decreased to zero. This would in practice mean, that EB capacity is actually sized to meet double of its nominal load. And yet, the full capacity is rarely utilised. Furthermore, the modelling method does not accurately depict the use of the heat storage as the capacity used changes in relation to changes in demand level as the optimisation solely shifts the hourly demand. This means that the storage is rarely, if ever, charged with full EB capacity. The levels of stored heat when modelling similar scenarios with different methods for heat storages for EBs is shown in Figure 33 and the resulting hourly electricity demand for DH EBs in both cases is shown in Figure 34. To better depict the behaviour of EBs and the use of the heat storage, the method with storage optimisation is chosen for case 4.

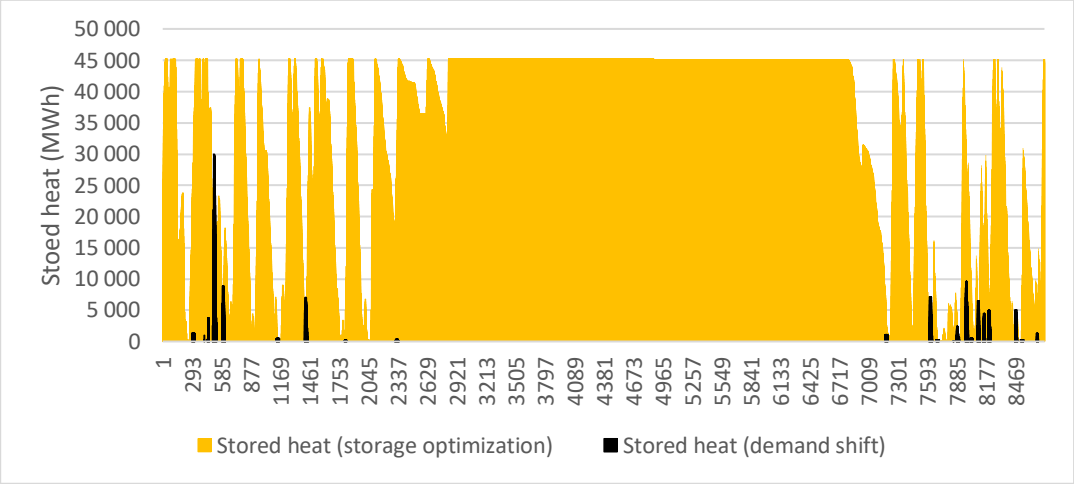


Figure 33: Levels of stored heat with different modelling methods

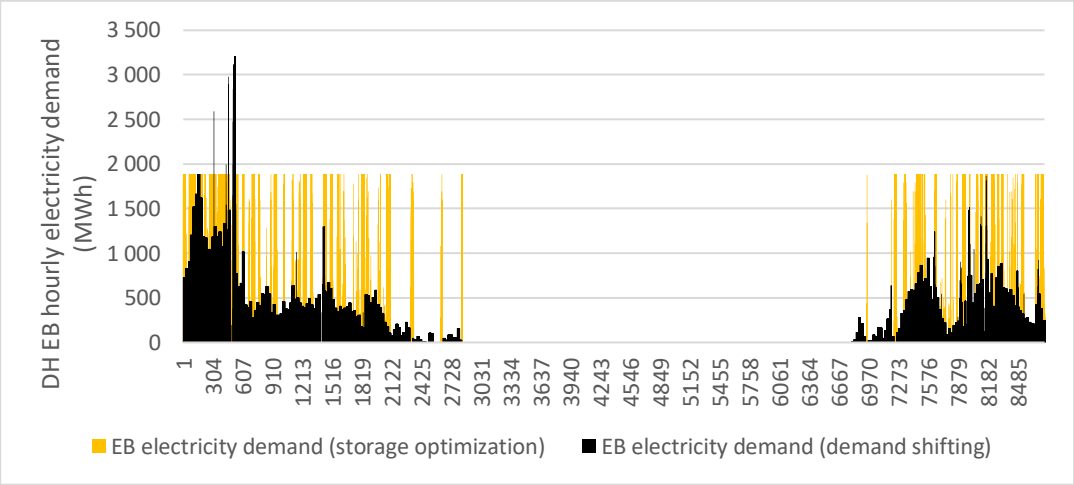


Figure 34: Hourly electricity demand for DH EBs in compared modelling methods

To estimate the electricity demand in the DH sector more accurately, a separate modelling scheme for district heating production would be needed to gain understanding of the impacts of alternative heat sources and their effects on the price and availability of flexibility. This would allow determining the merit order for heat production, which would also impact the hourly electricity demand for DH HPs and EBs and the operation of CHP plants. Alternative heat sources can also limit the operational speed of flexibility from the heating sector based on the dynamic operation capabilities of the heat production sources in the system. It could also enable cross-referencing scenarios of production capacity and electricity demand developments between the power and district heating sectors as the Autobuild module could be used to make investment analyses for the DH sector as well to gain better understanding of the development in DH production. This could help in determining future outlooks regarding CHP, DH HP, DH EB, and heat storage capacities. By adding the DH sector in the

modelling, the optimisation model could also consider investments in the heating sector, such as EBs and heat storages, as viable options for capturing low electricity prices and consequently mitigating price extremes in the system.

In practice, such detailed modelling of the DH sector would require breaking down the power market model to numerous sub-areas, essentially one for each city with a DH network, as city DH networks are not interconnected. This would require a great amount of work for possible a relatively limited gain, if considering that electricity consumption in DH represents around 5% of total annual electricity demand in current estimates. The modelling methods used in the thesis, or a mix of them, can be used to give a simplified approximation of electricity consumption in district heating. The developed demand profiles can be seen to better depict the operation of DH heat pumps and electric boilers.

5.3.2 Power-to-Hydrogen

There are currently significant uncertainties on the development of power-to-hydrogen. At this stage, the current modelling scheme can be considered to be the best estimate, as there is limited amount of information and historical data on how electrolysers operate on the power markets. However, as the scenario building and modelling is looking far into the future, estimates on the future development of the sector need to be made to assess the impacts on the power system. Currently, production and consumption of hydrogen is modelled with separate hydrogen areas. This is a valid modelling method as it allows for better assessment of long-term storage of hydrogen as well and allows estimating viability of hydrogen transmission between areas.

The cases used for analysing impacts of hydrogen production through water electrolysis are presented in brief in Table 8. In both cases, the demand for hydrogen is equivalent for all hours. In case 1, hydrogen is produced constantly with the electrolysers, leading to a stable demand of electricity year-round. In case 2, hydrogen storage capacity of 56,7 GWh is included, which allows for optimising the production of hydrogen to low-cost hours. Case 2 is used in all modelled heating cases. To meet the annual demand, a higher electrolyser capacity is required as for some hours the production is decreased and for some hours the production needs to be increased. Hydrogen transmission connections between hydrogen areas are not included in either case.

Table 8: Parameters for power-to-hydrogen in analysed cases

Case	Flexibility enabler	Electrolyser capacity (MW_{elec})	Storage capacity (MWh_{H2})	Charging power (MW_{H2})
1) Fixed	-	4 234	-	-
2) Flexible	Hydrogen storage	5 127	56 740	1 120

The modelling of hydrogen has been well developed in Fingrid as it has been in focus in the cooperation project with Gasgrid, where the joint design of electricity and gas network is studied (Fingrid Oyj, 2021i). However, there are still some things that could be included to improve the accuracy of the modelling and enable further use of the modelling results in analysing operational situations and impacts. The development in the field should be followed closely to assess if the demand for hydrogen can be modelled differently than with a constant fixed demand depending on the use case. For example, the demand profile for hydrogen in renewable fuel production could be different than for industrial use in the future. This could be a focus in discussions with stakeholders as well.

Currently, the Autobuild investment modelling used can only invest in alkaline electrolysers, for which a fixed efficiency of 70% is used. To enhance the accuracy, the model could be given all main electrolyser technologies, with their average efficiency levels and cost information. Of course, these are very uncertain when considering for example the year 2035. But as discussed in chapter 4, different electrolyser technologies have very different efficiency levels and in case of SOEC, also very different dynamic operation capabilities. A system dominated by SOEC electrolysers can be very different to that dominated by PEM electrolysers. If the technologies are separated in the investment and power market simulations, the analysis of the market data could be further used to analyse these effects.

Additionally, the model should be kept the option to produce hydrogen with other production methodologies than SMR with carbon capture and storage as well. SMR without CCS can still be a competitive option in the medium-term for hydrogen production in industry uses even with high emission allowance prices, especially as the cost of carbon capture and storage is expensive in Finland. The development of upcoming technologies such as hydrogen production through biomass gasification needs to be followed closely as well. This would enable increased flexibility for hydrogen production as a larger portfolio for alternative technologies is available. The option to invest in solely CCS should also be included. This gives facilities with existing SMR production in the model the option to decarbonise hydrogen production without the cost of investing in new SMR.

The cost development of electrolysers and the development of the hydrogen grid will have a significant impact on the development of power-to-hydrogen. Currently, it is assumed that all hydrogen demand is met with grid-connected electrolysers or SMR with CCS. However, as discussed in chapter 4, off-grid hydrogen production with direct connection to renewable power could become a competitive option. A hybrid setup with an optimally sized grid-connection and dedicated renewable energy production is also possible. At the first stages, it can be seen that hydrogen production will require a grid connection as the most efficient option to produce hydrogen with current electrolyser costs is to run them at high full-load hours per year. However, with decreasing costs of electrolysers and storage facilities, the hybrid and off-grid options become increasingly competitive and should be carefully taken into account in future scenarios. With off-grid hydrogen production, the impacts on the power system are non-existent and e.g., the estimates of grid-connected electricity demand and transmission needs are inherently lower. However, the availability of services provided to the grid by electrolysers, such as reserves, would also be lower.

6 Analysis of system operation impacts

In this chapter, the impacts of different modelling methods and developments paths of sector integration on power system operation are analysed. The focus is on studying the differences between chosen modelling methods and their consequences on power system operation. Aspects such as demand and value of flexibility or resulting electricity prices are not analysed. In this thesis, the results from power market modelling are analysed by a quantification method that focuses on analysing the hourly power changes and their impacts on system operation, mainly from the power balance management perspective. The quantification methods and tools for analysing power market simulation data from BID3 are developed by Visa Simola in his thesis "Quantification Methods for the Demand and Value of Flexibility" that was written at the same time as the author's thesis.

6.1 Power system scenario for 2035

The scenario used in the modelling is based on an ambitious draft scenario of Fingrid that is utilised in strategic grid planning. The base scenario has been made by the strategic grid planning unit in Fingrid. The modifications to the base case presented in chapter 5 have been made by the author. The scenario has been chosen as the base for all modelled cases as it has strong growth of variable renewable generation, but limited growth in flexible capacity, as the scenario does not have hydrogen transmission pipelines or significant growth in electricity transmission capacity. This is seen as a challenging base case for system operation.

The modelling of renewable generation is based on historical weather data, installed generation capacity and the location of renewable energy generation sites. Weather year 2016 is used for the modelling in the thesis. Production capacity to be installed during the year is not taken into account in the modelling. Stochastic modelling for hydro power is used to determine the option value for stored hydro power. Dispatch modelling of thermal generation is based on availability profiles, start-up costs and short-term marginal costs of production. Availability profile values vary based on scheduled yearly maintenances and interruptions caused by simulated faults. For example, nuclear power plants with very low marginal costs and high start-up costs operate at constant load except during maintenance and faults, whereas open-cycle gas turbines with high marginal costs but low start-up costs dispatch during peak power prices. For CHP plants, must-run profiles are also defined, which determine when the plants are required to operate. Must-run profile values for CHP plants in district heating are tied to the outdoor temperature, which reflects the increase in heat demand in DH

networks. For industrial CHP, the values are tied to process heating needs. CHP modelling is explained in more detail in the thesis of Tulensalo (2016). Cost parameters for energy resources and fuel prices used in the modelling are based on the ENTSO-E and ENTSOG Ten-Year Network Development Plan (TYNDP) National Trends -scenario, where no emphasis is placed on any particular technology. For the emission allowance price, development of hydrogen demand and potential of renewable generation, values from the Distributed Energy -scenario are used, as it best reflects the climate neutrality goals of Europe and it has the highest level of European energy self-sufficiency out of the scenarios (ENTSO-E & ENTSOG, 2022a; 2022b).

The most relevant data used in the modelled scenario for main import and export locations, namely Sweden and Estonia, is summarised in Table 9. Significant growth in installed wind and solar power capacities occur in both Sweden and Estonia. Sweden also has significant capacities in nuclear and hydropower. Thermal generation capacity consists of mainly CHP plants in Sweden and coal condensing plants in Estonia. Annual generation and demand of electricity increases in both countries. On an annual level, Estonia remains as an electricity importer and Sweden exports almost 30 TWh of electricity.

Table 9: Most relevant modelling data for Sweden and Estonia

	Sweden	**Estonia**
Annual generation (TWh)	274	10
Annual demand (TWh)	237	12
Wind power capacity (GW)	40,0	1,7
Solar power capacity (GW)	11,5	3,0
Nuclear power capacity (GW)	6,9	-
Hydropower capacity (GW)	15,7	-
Thermal generation capacity (GW)	4,4	0,7

The installed generation capacities in Finland in the scenario are presented in Figure 35. Import and export transmission capacities are presented in Figure 36. Significant growth is seen in installed wind and solar power capacities. Also, combustion based thermal generation capacity is significantly decreased as there is only 3800 MW of CHP capacity and 100 MW of open-cycle gas turbine (OCGT) capacity. Nuclear power capacity is estimated to increase to 5600 MW.

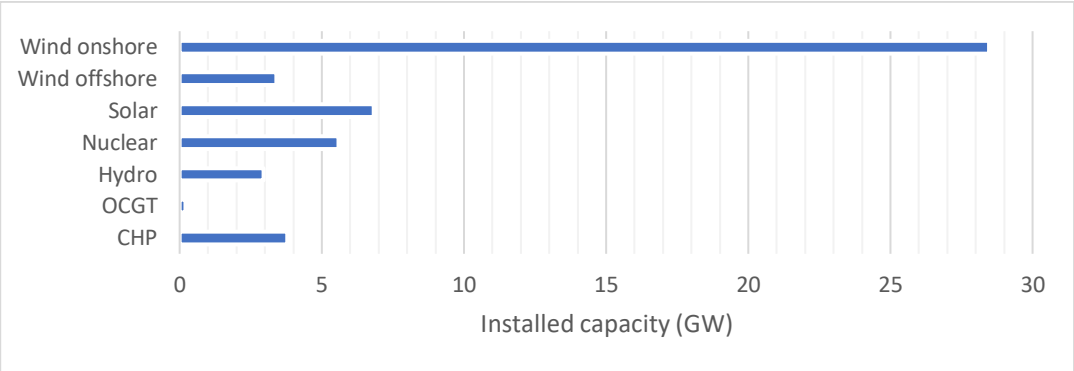


Figure 35: Installed generation capacity in 2035 by production type in modelled scenario

Flows between countries and market areas are dependent on the market area prices and transmission capacities. Electricity flows from areas with low electricity prices to higher price areas if there is transmission capacity available as explained in chapter 3. Dispatch modelling is done simultaneously for all market areas. Market areas outside of Finland are modelled in lower detail than the Finnish system and the parameterisation changes between different modelled cases are made solely in Finland. This is not seen to have a considerable impact on the results as changes in Finnish electricity demand are not likely to have considerable impacts on prices and flows, especially outside the Nordics. Additionally, the inaccuracies in market area prices and electricity transfers between areas are seen to have a limited effect on the results relevant to the thesis which focus on the operation of sector integration technologies. For the rest of Europe, the modelled scenario in terms of installed generation capacity and electricity demand is based on the ENTSO-E and ENTSOG Distributed Energy Scenario (ENTSO-E & ENTSOG, 2022a). Some adjustments are made based on data from Nordic grid companies and Fingrid's own calculations on the profitability of electricity and hydrogen production and storage.

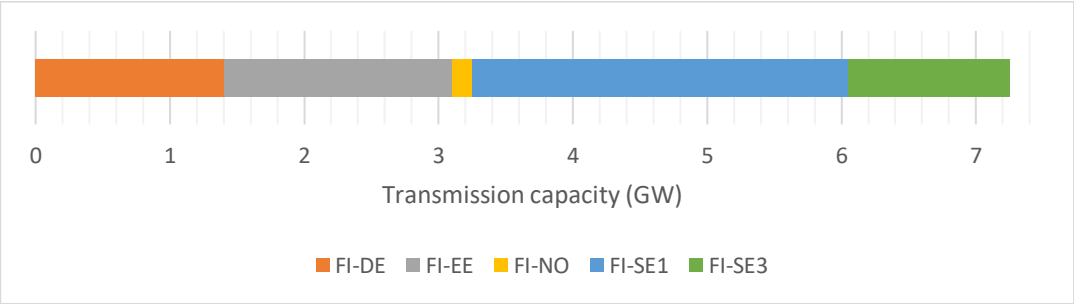


Figure 36: Transmission capacities between market areas in the scenario in 2035

Figure 37 presents the estimated annual electricity demand in the scenario for different demand groups in Finland for the year 2035. The figure shows the input demand used for the modelling. Final consumption is dependent

on the demand profiles, demand flexibility parameters and power prices. For example, with demand cutting, final electricity consumption will be decreased if power prices exceed the set threshold, as explained in chapter 5.2. Significant growth in electricity demand is estimated in district heating, electric vehicles, power intensive industry and electrolysis. In the scenario used, the total annual electricity demand reaches 163 TWh in 2035, which is twice as much as Finland's consumption in 2020.

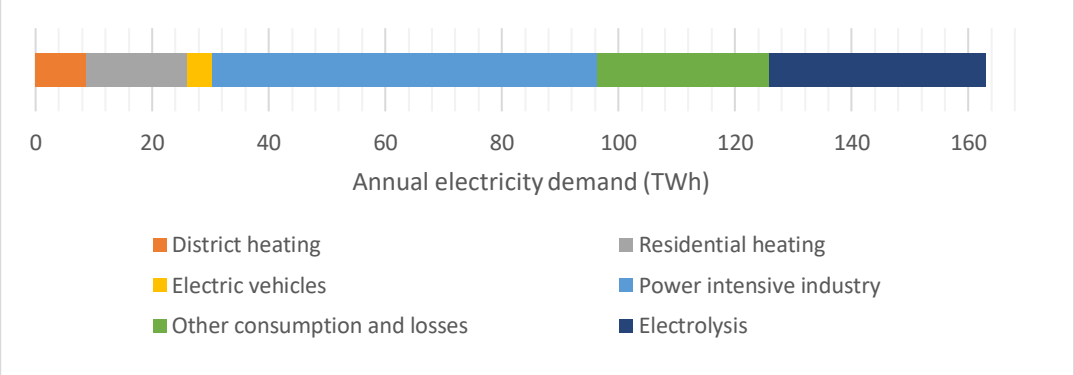


Figure 37: Annual input electricity demand in Finland for the year 2035 by demand group

6.2 Analysis of market modelling results

With the case studies presented in chapter 5.3., the impacts on short-term power changes can be studied for different development paths for district heating and hydrogen production. The analysis aims to provide an outlook on how different modelling methods and parameters for flexibility affect the operation of sector integration technologies in the power market simulations. The focus is on studying the magnitude of hourly power changes of electricity demand in district heating and electrolysis and on analysing how the changes correlate with changes in variable renewable energy production. Correlation with variable renewable generation changes is used to analyse whether the technologies are aiding the system to handle VRE production changes or whether they are increasing the magnitude of hourly power changes during high VRE production fluctuations.

6.2.1 Power-to-Heat in district heating

1) Base case and case with new demand profiles

The analysed cases for Power-to-Heat in district heating are presented in Table 7. Figure 38 shows the correlation of energy resource hourly power changes with the hourly power changes of renewable generation in the base case and with new demand profiles for district heating heat pumps and electric boilers. Renewable generation in this case consists of the sum of wind

and solar generation. The correlation coefficients have been calculated based on the hourly data of the modelled year, meaning a total of 8759 hourly changes. Positive correlation signals that when renewable generation increases between market hours, the demand or generation of listed resource also increases. Negative correlation signals that demand or generation of listed resource decreases between market hours when renewable generation increases. A high correlation coefficient value, negative or positive, signals that the energy resource adapts to the hourly changes in variable renewable generation well. In this thesis, differences in correlation coefficients between modelled cases are used to analyse system level changes in flexible resource utilisation between different modelling methods for district heating and hydrogen production.

High level observations from the figure are that hourly changes in electricity generation correlate very highly with changes in renewable generation, especially wind power. Lower correlation of offshore wind could be explained by the higher load factor of offshore wind and significantly lower installed capacity when compared to onshore wind in the scenario. From demand resources, charging of electric vehicles highly correlates with VRE changes. In the modelled cases it is assumed that 70% of electric vehicles utilise smart charging and have a vehicle-to-grid possibility. Electrolysis also correlates well, as hydrogen storage is included in all the modelled heating cases. Flexible generation technologies, such as hydro power and CHP, and electric storages, correlate negatively with VRE changes, as expected. When renewable generation increases, the wholesale price typically decreases, as seen in the correlations on Figure 38. This decreases the amount of flexible hydro and thermal generation. Charging of storages, in this case batteries and pumped hydro storage, is depicted by a negative correlation. Import and export of electricity also highly correlates with renewable generation changes.

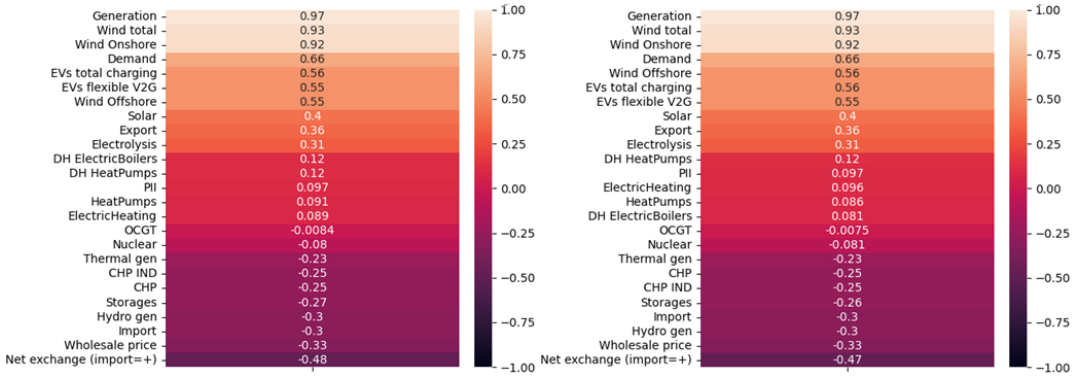


Figure 38: Correlation of energy resource hourly power changes with hourly changes of renewable generation in the base case (left) and in the case with new demand profiles (right)

This thesis focuses on studying the changes in correlations between modelled cases, focusing on the changes of correlation for district heating heat pump, electric boilers, and electrolysers. The correlation changes of other flexible energy resources are also discussed to gain understanding on how the decreased flexibility is compensated or what resources the increased flexibility seems to replace. In Figure 38, the correlation graphs for the base case and the case with new demand profiles are presented. As seen in the figure, no major differences between the two modelling methods can be seen. The main difference is the decreased correlation for DH EBs, which is likely result of the new demand profiles that set the electricity demand of EBs to zero during the summer period when heat demand is low. New demand profiles are used as basis for cases 2,3 and 4 as well. The cases are presented in detail in table 7.

Figure 39 shows the behaviour of DH EBs and HPs during the highest renewable generation hourly power changes in up-direction in
ft) and with new demand profiles (right). The graph aims to show how flexible district heating technologies operate during the highest VRE changes. If the electricity demand is increased in DH EBs and HPs, it can be thought to aid the system in managing the up-direction power ramps of renewable generation. A negative value for DH HP and EB one-hour ramps would mean that electricity demand is decreased when VRE generation increases rapidly. This would mean that demand in other sectors or export of electricity should be increased, or that either generation in other production modes needs to be lowered or renewable energy curtailed. In the figure, renewable generation power changes vary from roughly 1500 MW to 9500 MW between market hours. No significant changes in DH HP and EB can be seen between the two modelled cases. However, in the base case, higher hourly power changes can be seen in DH EBs at times than in the case with new demand profiles. Also, during some hours EBs have activated in the opposite direction when modelled with the new profiles. However, the magnitude has been very low.

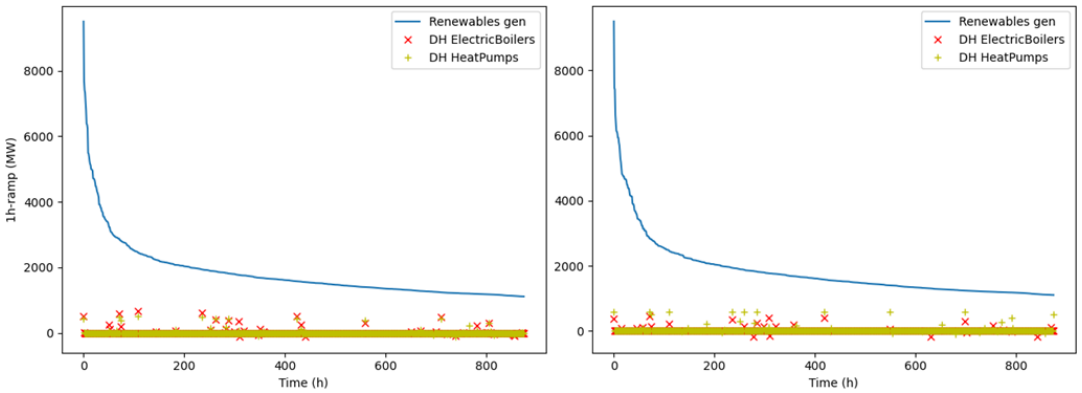


Figure 39: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (90th percentile) in base case (left) and with new demand profiles (right)

Behaviour of EBs and HPs during the highest down-direction changes of renewable generation are presented in Figure 40. Similar findings can be made as from figure 39. No significant differences between the two modelling methods can be seen, except that the activations of EBs are at times higher in the base case than with the new demand profiles. One high magnitude activation in the opposite direction, where electricity demand of EBs increased significantly between market hours, happened in the case with new demand profiles. During this change, the market price was at – 0,09 €/MWh during the hour and the hours close to it and the change in renewable generation was caused by renewable curtailment. Overall, when the demand flexibility is based on demand cutting based on price of electricity and the use of alternative resources for heating, the demand flexibility seems to aid the system to handle changes in renewable generation.

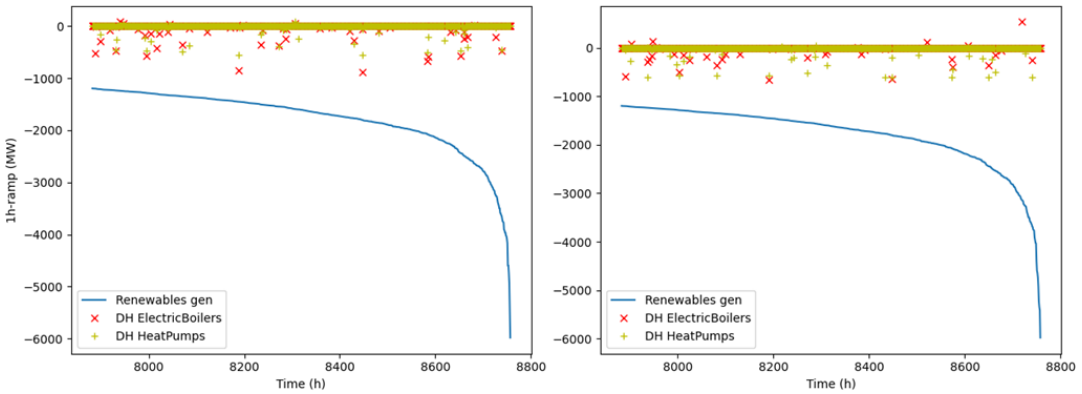


Figure 40: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (10th percentile) in base case (left) and with new demand profiles (right)

2) Flexible district heating

The correlations of energy resources with hourly changes of VRE generation in the case with highly flexible district heating are presented in Figure 41. Against initial assumption, correlation of DH heat pumps stays at a similar level than in the base case. Correlation of DH EBs increases when compared to the case with new demand profiles. On a high level, other significant changes between the flexible case and the base case cannot be seen. As mentioned before, new demand profiles are used in the flexible case, as well as in cases 3 and 4.

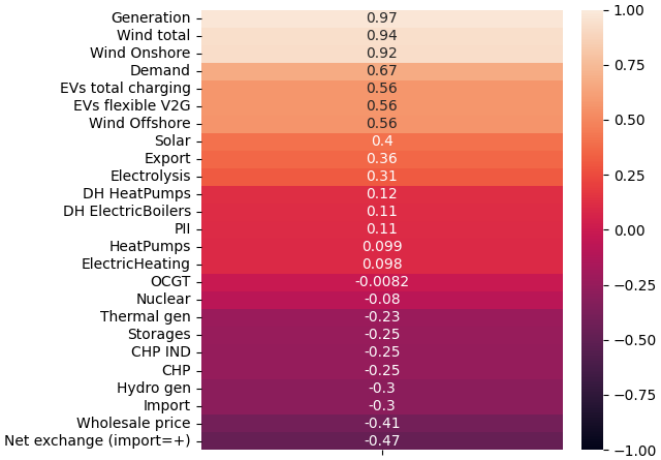


Figure 41: Correlation of energy resource hourly power changes with hourly changes of renewable generation with flexible district heating (case 2)

Figure 42 shows the behaviour of DH EBs and HPs during high VRE changes in the highly flexible district heating case. The figure shows that the activated flexibility is higher for DH EBs and HPs than in the base case, causing higher hourly changes in demand. This is due to the fact that the flexibility percentage is higher than in the base case. Additionally, the number of activations for both HPs and EBs is higher in the flexible case, which is likely the result of the lower threshold price for both EBs and HPs, which causes EBs and HPs to be inactive for a higher number of hours. This means that EBs and HPs can increase their demand and therefore offer downregulation more often. No significant decreases in electricity demand in DH EBs or HPs occur during the highest VRE changes. Figure 43 shows the hourly demand changes of DH EBs and HPs during the highest down-direction ramps in VRE generation. One occasion can be seen for both EBs and HPs, where demand has increased as VRE production has dropped. Both demand increases happened during renewable curtailment periods, when market price was below zero. In many cases with large up- and down-direction changes renewable curtailment has been the triggering factor.

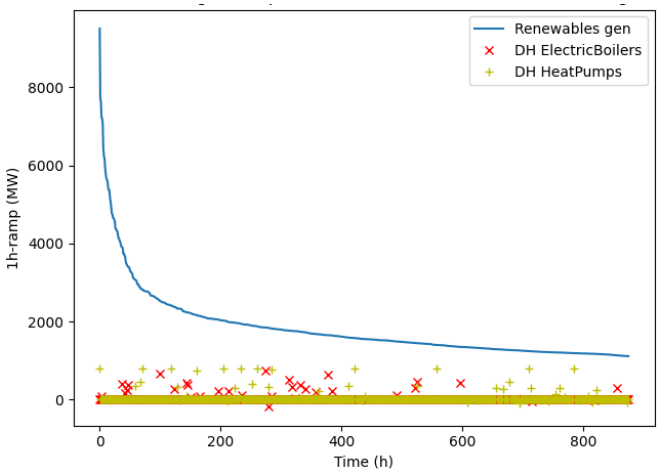


Figure 42: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (90th percentile) in flexible heating case (case 2)

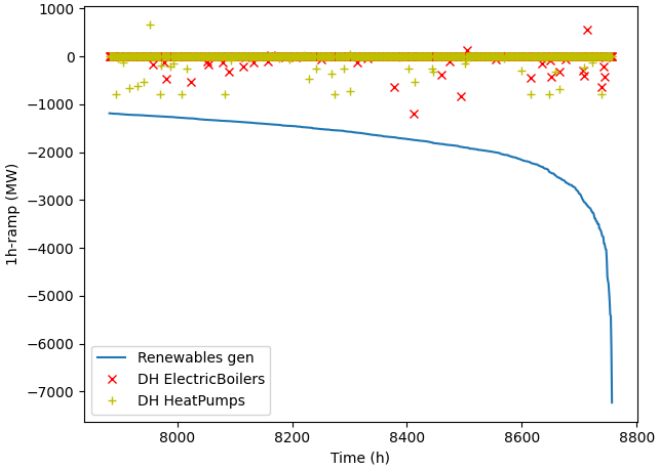


Figure 43: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (10th percentile) in flexible heating case (case 2)

3) Fixed demand in district heating

In case 3, electricity demand in district heating is not flexible. This means that the electricity demand of EBs and HPs blindly follows the changes in heat demand, and they will not decrease consumption of electricity at any market price. As explained in chapter 5.3.1, the case is quite an unrealistic development path of DH electricity use. However, the case can be used to depict the challenges caused by inflexible electricity demand in heat production and it works well as a comparison case to the flexible cases. The correlation coefficients of energy resources with hourly changes of VRE generation in the fixed case are presented in Figure 44. In the fixed case, essentially no correlation with renewable generation changes and DH EBs and HPs can be seen, as the electricity demand blindly follows the changes in heat demand for both technologies. Correlation is increased slightly for export and import of electricity, electricity storages and OCGTs, when compared to the base case. Negative correlation of wholesale price significantly decreased in the fixed case when compared to the base case and flexible case.

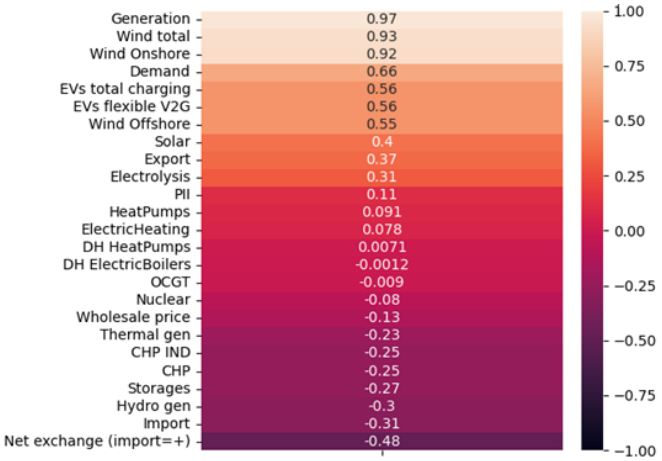


Figure 44: Correlation of energy resource hourly power changes with hourly changes of renewable generation in the fixed case (case 3)

Figure 45 shows the behaviour of DH EBs and HPs during high VRE changes in the fixed district heating case. In the fixed case, the electricity demand changes follow the changes in heat demand. No significant power changes seem to happen during the highest VRE changes. The hourly changes caused by heat demand changes are mostly at low level, below 200 megawatts. DH EBs and HPs in this case are not aiding the system to handle VRE changes, but they also are not making things much worse by decreasing their demand during VRE changes. An initial assumption was made that changes in weather could cause both high VRE ramps and rapid changes in the electricity demand for DH EBs and HPs due to temperature changes. Figure 46 shows that during high decreases of VRE generation, EB demand has in a

few cases increased quite significantly. In these cases, the demand has increased between 300 to 500 megawatts between market hours.

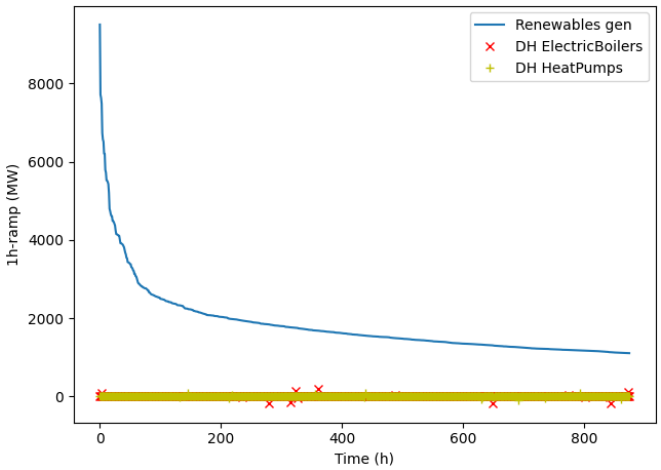


Figure 45: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (90th percentile) in the fixed case (case 3)

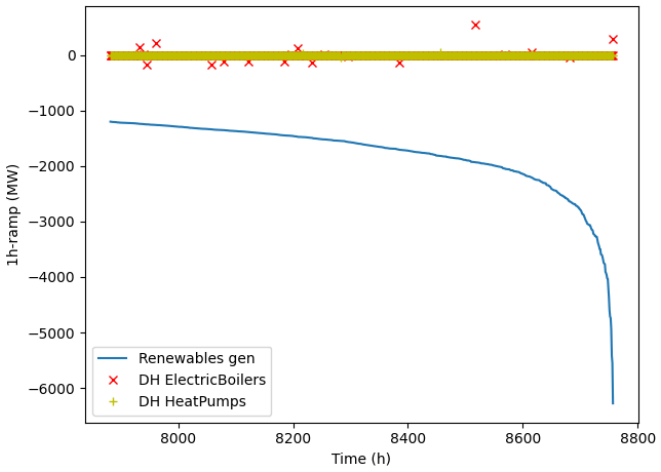


Figure 46: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (10th percentile) in the fixed case (case 3)

4) Electric boilers with heat storages

The last analysed case differed from the previous case as the operating logic for flexibility was different for DH EBs. In case 4, DH EBs are used to charge a heat storage and the heat storage is used to cover the heat demand allocated to EBs. Electricity demand of DH EBs is therefore optimised to charge the storage during lowest electricity price hours. Figure 47 presents the correlation coefficients of energy resources with hourly changes of VRE generation in case 4. In the case with heat storage, the positive correlation of EBs with VRE changes increases significantly. However, the correlation is still much smaller than for electrolysis. This is likely due to higher storage

capacity for hydrogen and the difference in demand profiles. For hydrogen, the demand is fixed for the whole year, whereas for electric boilers, the demand varies a lot and is zero for a long time during the summer period. The correlation of import and export of electricity and electricity storages decreased slightly. The negative correlation of wholesale price decreased significantly.

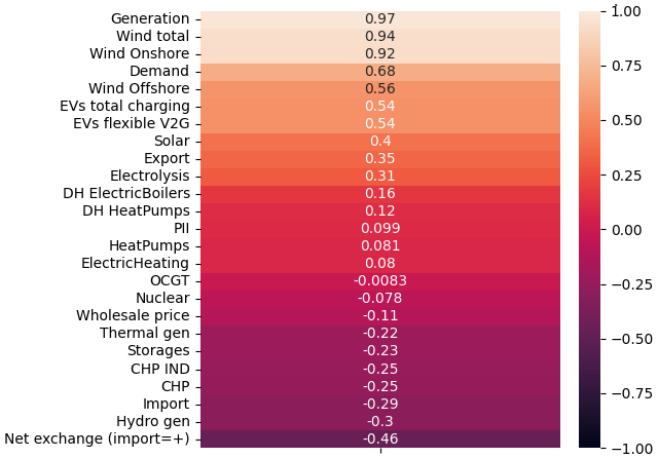


Figure 47: Correlation of energy resource hourly power changes with hourly changes of renewable generation in case 4 (EBs with heat storage)

Figures 48 and 49 show the behaviour of DH EBs and HPs during the highest VRE hourly generation changes. In the case with heat storage, the magnitudes of power changes are at a higher level as full EB capacity can be utilised flexibly. There are some cases where activation of flexibility has happened in the opposite direction of VRE changes. This can be caused by the limited amount of storage. Optimisation follows market price signals, which generally follow changes in VRE generation as seen in previous cases, but the optimisation is constrained by the storage capacity and current and upcoming demand levels. An interesting finding is that more activations in the opposite direction occur in the storage case than in the fixed case. In most cases, the electricity demand of DH EBs is aiding the system well and with high power, but in some cases, EB use with heat storages can actually increase the flexibility need in the system.

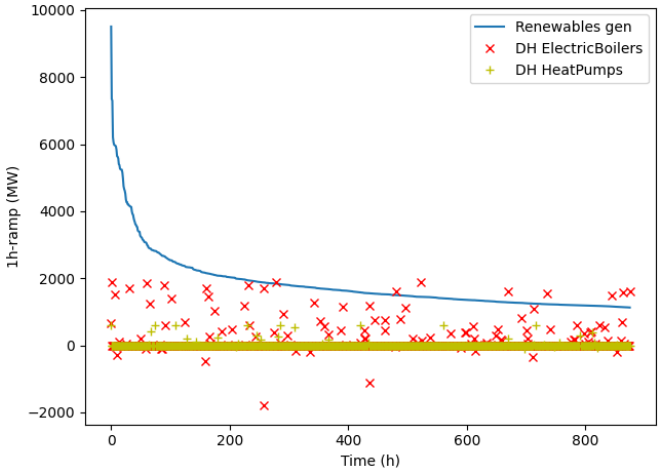


Figure 48: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (90th percentile) in case 4 (EBs with heat storage)

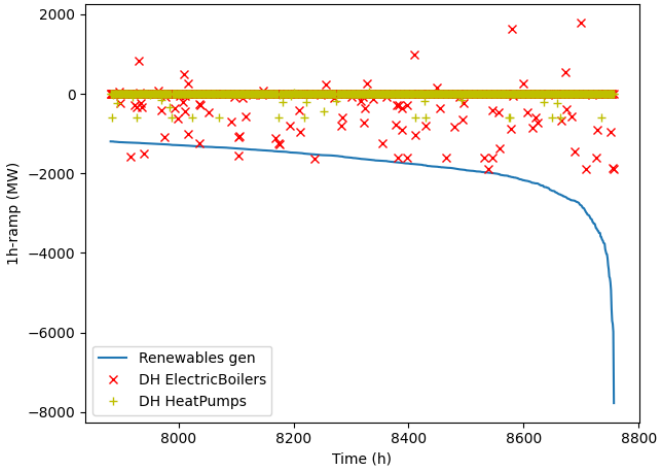


Figure 49: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (10th percentile) in case 4 (EBs with heat storage)

The magnitude of highest hourly power changes (top 200 hours) of DH technologies in different cases can be seen from the duration curves presented in figures 50 and 51. The full duration curves are presented in appendix E. Power changes between market hours are higher in all flexible cases than in the fixed case. By far the highest changes for EBs take place when heat storages are implemented, as full EB capacity can be utilised for flexible heat production. In other cases, flexible capacity is based on the hourly electricity demand, which is tied to hourly heat demand, and the allocated flexibility percentage. Higher power changes mean that the technologies can aid the system to react to VRE changes and market price changes with a higher degree, but they can also increase the magnitude of errors in forecasts used in power system operation.

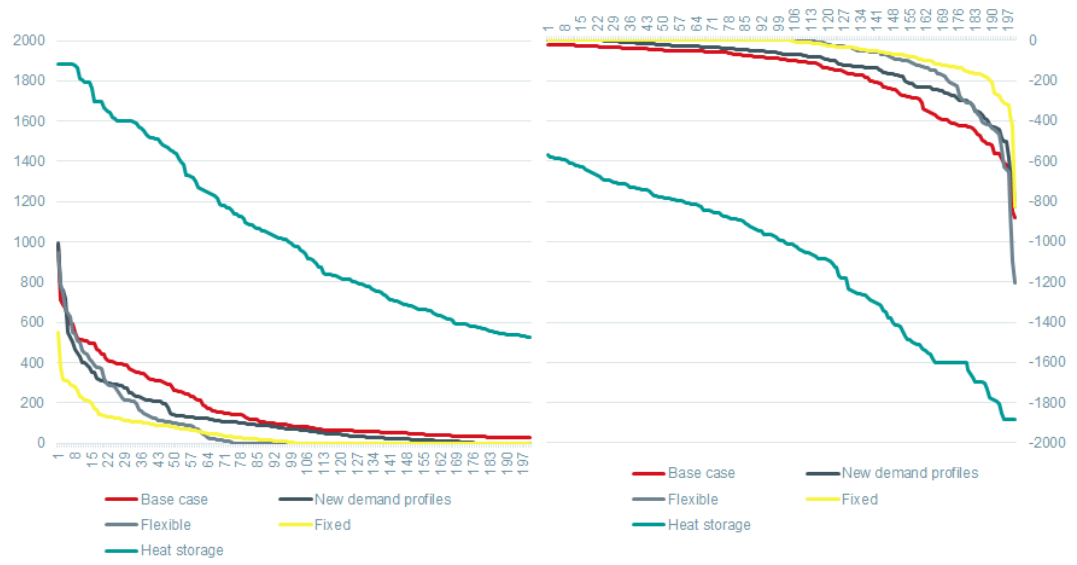


Figure 50: Highest hourly changes in electricity demand (MWh/h) for DH electric boilers in modelled heating cases (top 200 hours)

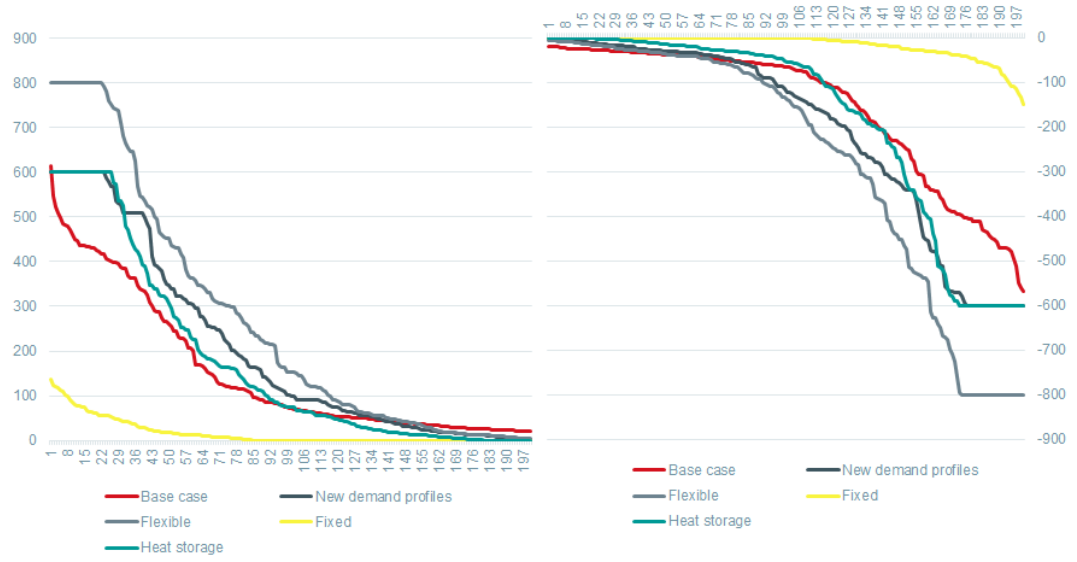


Figure 51: Highest hourly changes in electricity demand (MWh/h) for DH heat pumps in modelled heating cases (top 200 hours)

6.2.2 Power-to-Hydrogen

Two cases for electricity use for hydrogen production have been studied in the thesis. In the fixed case, electricity demand of electrolysis is fixed for all hours of the year, leading to zero flexibility in hydrogen production. In the flexible case, hydrogen storage allows for optimising hydrogen production based on electricity prices. The studied cases are presented in more detail in chapter 5.3.2 and in Table 8. Figure 52 shows the correlation of energy resource hourly power changes with the hourly power changes of renewable

generation in the fixed and flexible cases. As expected, there is no correlation of electrolysis power changes with the changes in renewable generation, as demand for electrolysis does not change between market hours. Based on the changes in correlations, flexibility of electrolysis is most likely compensated by EV flexibility, export and import of electricity, DH HPs and EBs and power intensive industry. It is noteworthy, that the correlation of thermal generation is hardly impacted, as well as the correlation of electric storages. Negative correlation of wholesale price is significantly smaller in the fixed case than in the flexible case.

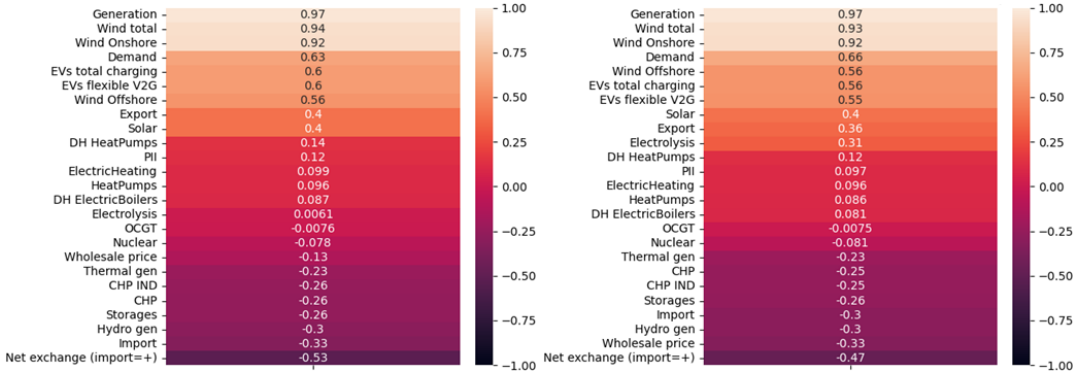


Figure 52: Correlation of energy resource hourly power changes with hourly changes of renewable generation in hydrogen fixed case (left) and flexible case (right)

Figures 53 and 54 show the behaviour of DH EBs and HPs during the highest VRE hourly generation changes. As expected, no changes in electrolysis electricity demand take place in the fixed case. Fixed demand is not aiding the system during high VRE changes, but it is not making things worse either. In the flexible hydrogen production case, changes in electrolysis electricity demand seem to aid the system well. One case with opposite direction activations can be seen during high up-direction power ramps of VRE and two cases during ramp downs. Notable, that opposite direction activations are very rare, which differs from the case with heat storages. This could be explained by the higher storage capacity and lower charging power of hydrogen storage, which increases the time window for charging and discharging the storage. In the heat storage case, the storage size is equivalent to 24 hours of full capacity charging hours, whereas in the hydrogen case it is around 50 hours.

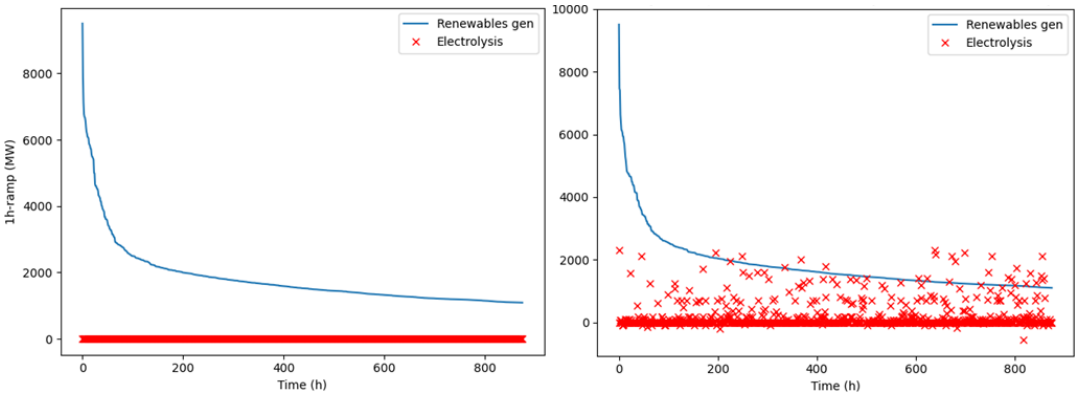


Figure 53: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (90th percentile) in hydrogen fixed case (left) and flexible case (right)

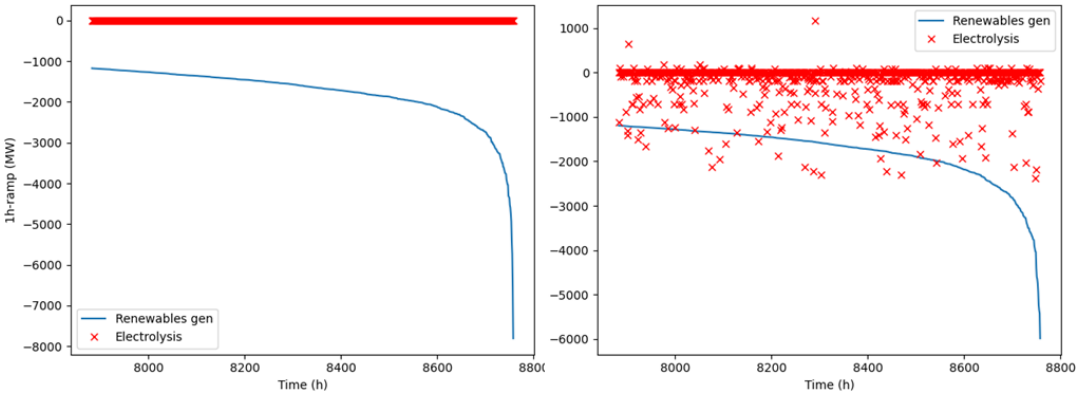


Figure 54: Behaviour of DH EBs and HPs during the highest renewable generation hourly power changes (10th percentile) in hydrogen fixed case (left) and flexible case (right)

The duration curves of hourly changes in electricity demand for electrolysis in the fixed and flexible case are shown in Figure 55. As expected, no changes happen in the fixed case. In the flexible case, the highest hourly changes reach nearly 2500 megawatts. Electrolysis is ramped up for roughly 2000 hours in the modelled year and ramped down for roughly 1500 hours. During most hours, the activated flexibility is below 1000 MW, meaning that full flexible capacity set by the electrolysis capacity and charging and discharging capacity of the hydrogen storage is rarely used for quick ramp-ups or ramp-downs between market hours.

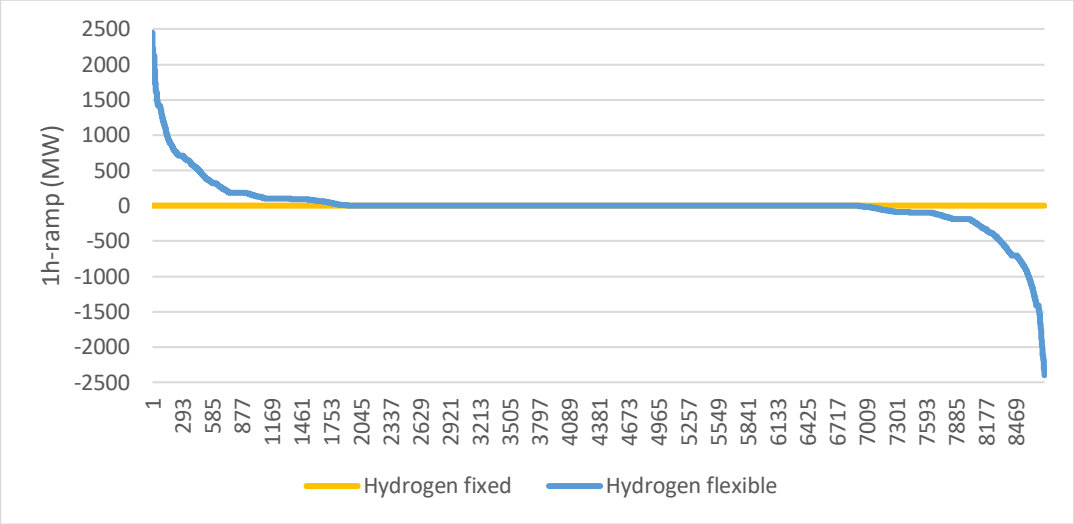


Figure 55: Duration curve of hourly changes in electricity demand for electrolysis in modelled hydrogen cases

During the analysation of the modelling data, it was seen that many of the cases with high hourly changes in renewable generation were caused by renewable curtailment, which resulted in quick up- and down-ramps in renewable generation. Consequently, during all large VRE changes, market price was not affected, as the market price stayed at zero or slightly below zero. This means that resources are not receiving clear signals to activate flexibility in the modelling. However, as the market price is at zero or below, it was already encouraging participants to keep demand on a high level. In some cases, available storage capacity could limit keeping the demand at a high level, resulting in demand cutting and opposite direction activations, as seen in the modelled case with heat storage. Total renewable generation curtailed in the studied cases during the modelling year is presented in Figure 56. The total annual VRE generation in the cases is between 104 to 107 terawatt hours, varying based on the curtailed amount. The most significant changes can be seen in the cases with heat storage and without hydrogen storage. The heat storage case also includes hydrogen storage. In the heat storage case, the curtailed amount is decreased 0,7 TWh compared to the base case. In the hydrogen fixed case, renewable curtailment increased 1,4 TWh compared to the base case.

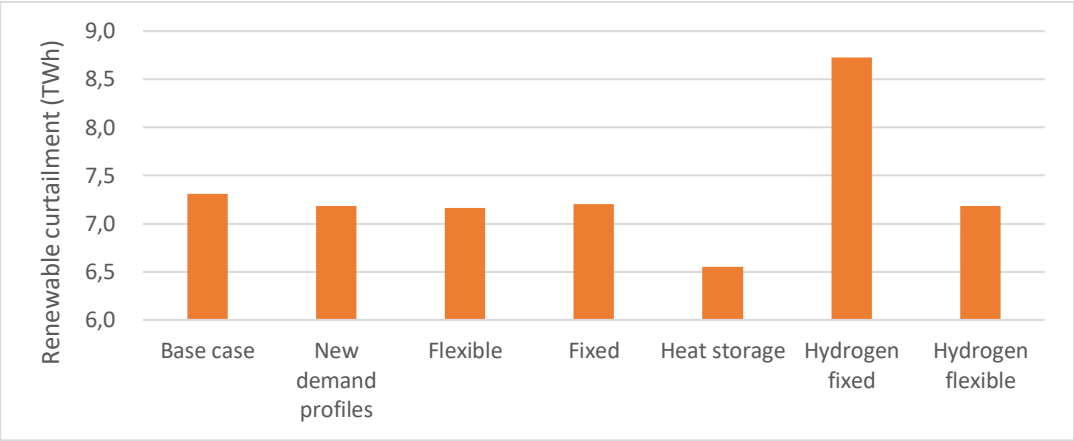


Figure 56: Annual renewable generation curtailment in analysed cases

7 Summary and conclusions

In the literature review, data from existing sector integration implementations in Finland and other European countries, and findings from pilot projects, were used to analyse the operation of sector integration technologies. The thesis focused on large-scale heat pumps and electric boilers in district heating and electrolysers used for hydrogen production. According to the findings, large-scale district heating heat pumps are typically operated in the base-to-mid load region, leading to high annual full load hours. Flexible operation can be limited by the utilised heat source, lack of alternative heating technology or unavailability of heat storage. Electric boilers in district heating are typically used as peak load technologies during low electricity prices. Currently, the high capital costs of electrolysers favour their use at high full load hours. However, as the marginal cost of hydrogen production is tightly linked to the cost of electricity, flexible operation based on electricity price is likely to grow in the future as capital costs decrease. In practice, flexibility is dependent on the flexibility of hydrogen demand and the availability of an alternative source of hydrogen or a storage of hydrogen. Dynamic operation capabilities of electrolysers and electric boilers allow for very rapid changes in consumption allowing the technologies to participate in many, if not all, reserve markets.

Regulation can have a significant impact on the development of future operational principles in hydrogen production. For all technologies studied, but especially for electric boilers and electrolysers, a capacity-based grid tariff structure can discourage investments in flexible capacity as the potential cost savings from flexible operation can be lower than the increased capacity charge resulting from higher peak loads. Energy component-based tariffs, dynamic tariffs or lowering capacity tariffs and making them payable annually would be better alternatives to maximise flexibility. Flexible connection agreements could be utilised to ensure sufficient transmission capacities during the peak loads.

The modelling of the electricity system should in the future better take into account other energy sectors to be able to reliably assess electricity production and demand, and the resulting impacts on the power system, if the modelling is to be used to assess operational situations and challenges in system operation. Overall, with the current state of modelling, the operational behaviour and constraints of different energy sectors are not accounted for very accurately. Separate sector modelling could allow more accurate estimates of the behaviour of electricity demand in growing energy sectors, as well as installed capacity and general demand trends. It would also create a better understanding of operational constraints regarding flexibility

from different energy sectors and increase the accuracy of combined heat and power modelling.

One of the identified and expected impacts of sector integration is the increase of electricity demand that optimises the consumption of electricity based on the market price of electricity. Depending on the bidding strategy of the market participant, and the technical capability of the technology to offer ancillary services, the market price signal to increase or decrease electricity demand can come from the day-ahead or intraday markets or from reserve markets. If flexibility is utilised through the day-ahead and intraday markets, it can cause errors in balancing and system operation planning if not forecasted. If utilised through reserve markets, changes are essentially controlled by the system operator.

Currently, Fingrid's demand forecasts do not utilise price forecasts or realised day-ahead market prices. This means that the link between electricity price and electricity demand is not directly considered in the forecast. Forecasts are essential tools in power balance management in the grid control center, as they give insight on what the power balance for the upcoming hours looks like and therefore signal the need for reserve and regulating power. Forecast errors or unforeseen changes in demand do not directly cause imbalances in the system if they are already remedied by the market participants through power markets or by the balancing responsible party. Forecast errors, on the other hand, can lead to incorrect decisions in system operation if proactive decisions are made based on the forecasts. Additionally, dynamic operation capabilities of sector integration technologies, especially electric boilers and some electrolysers technologies, allow for rapid changes in demand, which in itself can pose challenges to system operation. It should be noted, that forecast errors in the power system are not a new phenomenon. Forecast errors in the system have become common with the increase of weather dependent generation. Even though the accuracy of renewable generation forecasts improves, the magnitude of errors will increase as the installed capacity grows. On-going market developments and the increase in renewable generation emphasise the importance of reactive balancing and decision-making in power system operation and the importance is further highlighted by the increase of flexible and price-dependent demand.

The market modelling demonstrated that higher flexibility for sector integration technologies leads to higher hourly changes. Higher hourly changes mean that the technologies can aid the system by reacting to changes in renewable generation and electricity prices with a higher degree. However, higher flexible capacity can also lead to higher magnitude errors in demand forecasts used in system operation that could have significant impacts on

system operation activities, as explained before. Currently, operators in the grid control center can make own adjustments in forecasts based on their expertise and market price, but as the system changes to operate in 15-minute resolution, the time window for expert assessments and manual adjustments is limited. In the future, the system is based to an increasing extent on forecasts and automated decision making.

If a forecasting model capable of learning and identifying the causes for forecast errors is developed, the operating principles of flexible demand should sooner or later be understood, as large-scale resources are likely to be operated under specified principles and constraints. If the forecasts would be made on a more local level, for example, substation specific, identifying these forecast errors from measured data could be easier than with grid scale forecasts (Richter, Schroeter, & Wolter, 2021). This would also help in assessing congestion management needs in a more detailed level than currently is done. It should be noted that a significant amount of sector integration technologies will also come to the small consumption side in form of for example electric vehicles and residential heat pumps. The operation of small and distributed loads can be much harder to predict. With distributed resources, demand can vary for a number of reasons, not all of which are completely deterministic. Before forecasting models are further developed or a shift towards fully reactive operation is made, an interim solution might be needed to ensure stable system operation. One solution could be to start acquiring consumption plans from large-scale loads that are then used in demand forecasts. This could also benefit market participants as it can enable more stable system operation. Discussions with market participants, especially balancing responsible parties and large industrial consumers, should be kept through to gain their views on the subject.

The energy system, and the electricity system with it, is going through major transformations. In aims to reduce emissions, demand for electricity in the energy sectors is seen to grow rapidly, making room for investments in electricity production. However, currently the most competitive electricity production technologies are variable renewables. If new electricity demand driven by sector integration and electrification is not flexible, it can create a need for electricity that at times cannot be met with the current production portfolio during times of low renewable generation. In this case, new demand can become a consumer of flexibility instead of a source. This would put even more strain on the rapidly increasing flexibility requirements of the power system.

8 Discussion

This thesis is merely a small step towards holistic energy system modelling, which takes into account the operational constraints of different energy sectors better when considering their actions on the power market and, consequently, the potential effects on electricity demand, demand fluctuations and prices. The findings can be used for analysing the operation of new technologies but also to better assess the potential and electricity demand growth in different sectors. Triggers affecting the development are also discussed. All of the modelled and analysed cases have their own drawbacks that are explained in chapter 5. However, they can be utilised to show the systemic changes and impacts of different modelling methods with different enabling factors for flexibility. It should be noted that the modelled cases studied are developed for studying power system operation impacts of sector integration. They are not attempts to predict the future nor should they be taken as such.

As discussed before, as the share of renewables grows and conventional generation decreases, the need for obtaining system services from new resources becomes inevitable. Especially during hours with high renewable production, the amount of conventional synchronous generators connected to the network can be very little. A fundamental advantage of demand side response from the standpoint of service provision is that, even during periods of high renewable production when there may be limited amount of synchronous generation online, demand will be present. It can be expected that also flexible demand that is optimising consumption based on the market price is online during these times, as the higher share of renewable production typically correlates with lower market prices. Procuring system services from a wider range of resources can be an opportunity, or later even a necessity, for the system operators. For example, during planned interruptions, in many cases the transmission capacity is not the limiting factor, but it is actually the voltage support in the local network (Huttunen and Mäkihannu, 2021). For example, in a scenario where no conventional generation is dispatchable in the local network during the planned interruption in, it becomes a necessity to find alternative resources (EirGrid Plc & SONI Ltd, 2021). Further studies should further analyse market modelling results in order to gain understanding of system and regional level operational situations and their effects on the acquisition of ancillary services.

Another aspect that requires further research is congestion management and especially the effect of new electricity demand on occurring bottlenecks and in which ways flexible demand can help alleviating them. Further studies should also analyse the effects of different modelling methods and flexibility

levels on electricity prices and on the value of flexible operation for market participants. Additionally, hourly level demand profiles for residential and district heating could be studied to analyse if the higher peaks and valleys in demand lead to more difficult operational situations than when modelled on hourly resolution. If seen applicable, the data of Helen district heating production could be used to analyse the weather dependency of district heating heat demand. This could be further used to construct heat demand profiles for other district heating systems in Finland as well based on their local weather data. It should be noted that the weather and heat demand correlation can differ in different district heating systems. Further studies should also include a larger number of modelled weather years to analyse operational situations and impacts during cold, warm, dry, and wet years. In the thesis, year 2016 was chosen as a case year to analyse impacts on a cold year.

One of the major questions is how to assess the need for and value of short-term and long-term flexibility from power system operation perspective, and how to accurately encourage investments that do not appear economically optimal to the market participants solely based on cost savings from market optimisation but lead to increased welfare on the system level. From a system planning perspective, the increase in flexibility would result in higher peak loads for flexible consumers, which needs to be taken into consideration also in grid planning. Innovative solutions for connecting to the grid, such as flexible grid connection agreements, could be made so that the peak demand of flexible consumers does not coincide with other peak demand times, to ensure cost-optimal sizing of transmission capacity.

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Appendices

Appendix A. Technical requirements of reserve products in Finland (Fingrid Oyj, 2021d)

	FCR-N	FCR-D	aFRR	mFRR	FFR
Activation type	Automatically at frequency deviation 100 % when f =< 49,9 Hz or >= 50,1 Hz Proportional to frequency deviation when f between 49,9 - 50,1 Hz	Automatically at frequency deviation 100 % when f =< 49,5 Hz or f >= 50,5 Hz Proportional to frequency deviation when f between 49,5 - 50,5 Hz	Centralized automatic activation if frequency deviates from 50 Hz	Centralized manual activation	Automatically at frequency deviation
Ramp-up time	100 % within 3 min	50 % in 5 s 100 % in 30 s	100 % in 5 min	100 % in 15 min	100 % max 1,3 s if f =< 49,7 Hz 100 % max. 1,0 s if f =< 49,6 Hz 100 % max. 0,7 s if f =< 49,5 Hz
Minimum dimensioning	Full activation for entire delivery period If limited capacity, at least 30 min of continuous full activation	Full activation for entire delivery period If limited capacity, at least 30 min of continuous full activation	1 h	Min. 1 h Min. 3 h (mFRR CM)	Min. 30 s if maximum speed of deactivation is not limited Min. 5 s if deactivation speed =< 20 % reserve capacity per second
Rest period	NA	15 min	NA	At least 3 h, but at most 6 h (mFRR CM)	15 min
Minimum size	0,1 MW	1 MW	1 MW 60–80 MW (certain morning and evening hours only)	10 MW manual activation 5 MW electronic activation 1 MW for one bid per BRP	1 MW
Volume (2021)	123 MW	about 300 MW		880–1100 MW	about 0–60 MW

Appendix B. Data of large-scale district heating heat pumps in Finland (Energiateollisuus, 2022)

	2014	2015	2016	2017	2018	2019	2020
Fortum Power and Heat, Suomenoja 4							
Installed capacities		40 MW_{heat}; 11 MW	40 MW_{heat}; 11 MW	40 MW_{heat}; 11 MW	40 MW_{heat}; 11 MW	40 MW_{heat}; 11 MW	40 MW_{heat}; 11 MW
Produced heat (GWh)		227,2	349,1	393,7	377,6	354,5	371,4
Electricity used by HPs (GWh)		94,2	96,6	102,9	100,5	90,6	98,4
COP		2,4	3,6	3,8	3,8	3,9	3,8
FLH based on electricity use		8 564	8 782	9 355	9 136	8 236	8 945
Helen Oy, Katri Vala and Esplanadi							
Installed capacities	90 MW_{heat}; 30 MW	90 MW_{heat}; 30 MW	90 MW_{heat}; 30 MW	90 MW_{heat}; 30 MW	127 MWheat; 37,6 MW	127 MWheat; 37,6 MW	127 MWheat; 37,6 MW
Produced heat (GWh)	374,9	422,0	490,5	565,0	576,0	543,6	495,0
Electricity used by HPs (GWh)	120,9	127,2	124,5	145,5	139,0	133,6	122,0
COP	3,1	3,3	3,9	3,9	4,1	4,1	4,1
FLH based on electricity use	4 030	4 240	4 150	4 850	3 697	3 553	3 245
Turun Seudun Energiantuotanto Oy *1, Kakola							
Installed capacities	42 MWheat; 13 MW *2	42 MWheat; 13 MW	42 MWheat; 13 MW	42 MWheat; 13 MW	42 MWheat; 13 MW	42 MWheat; 13 MW	42 MWheat; 13 MW *3
Produced heat (GWh)	221,1	156,9	252,2	265,5	257,1	255,9	534,2
Electricity used by HPs (GWh)	72,7	100,9	89,0	82,2	83,5	73,8	83,0
COP	3,0	1,6	2,8	3,2	3,1	3,5	-
FLH based on electricity use	5 592	7 762	6 846	6 323	6 423	5 677	6 385
Nivos Vesi ja Lämpö Oy, Yandex LTO							
Installed capacities	-	3,6 MW_{heat}; 1,2 MW	3,6 MW_{heat}; 1,2 MW	3,6 MW_{heat}; 1,2 MW	3,6 MW_{heat}; 1,2 MW	6 MW_{heat}; 1,5 MW	6 MW_{heat}; 1,5 MW
Produced heat (GWh)		2,9	16,1	22,4	23,5	27,3	29,7
Electricity used by HPs (GWh)			5,1	6,8	7,5	8,5	9,3
COP			3,2	3,3	3,1	3,2	3,2
FLH based on electricity use			4 250	5 667	6 250	5 667	6 200

*1 Kakola HP part of Turku energia in 2010

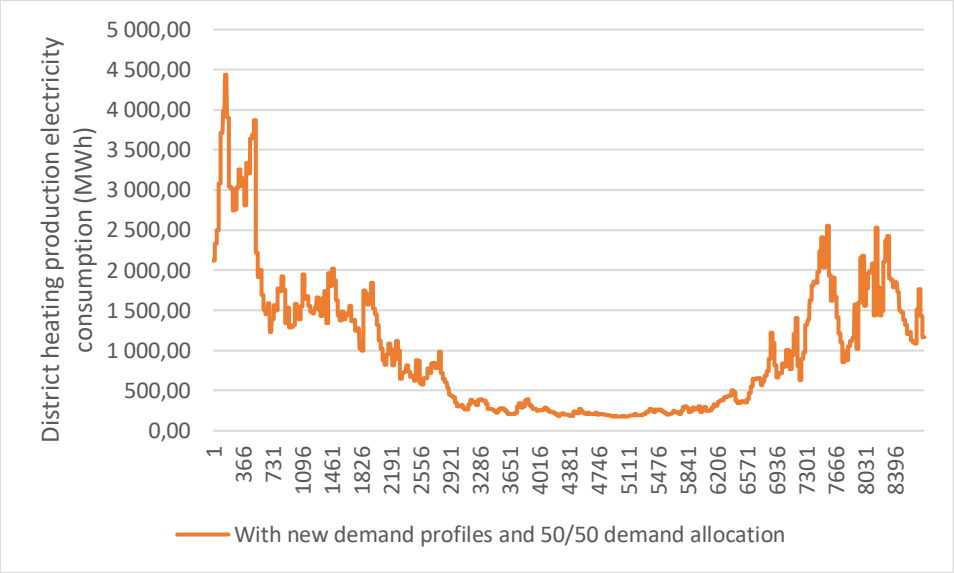
*2 installed in 2013 but not listed until 2018

*3 In 2020 71,8 MW of heat recovery power not related to HP production reported

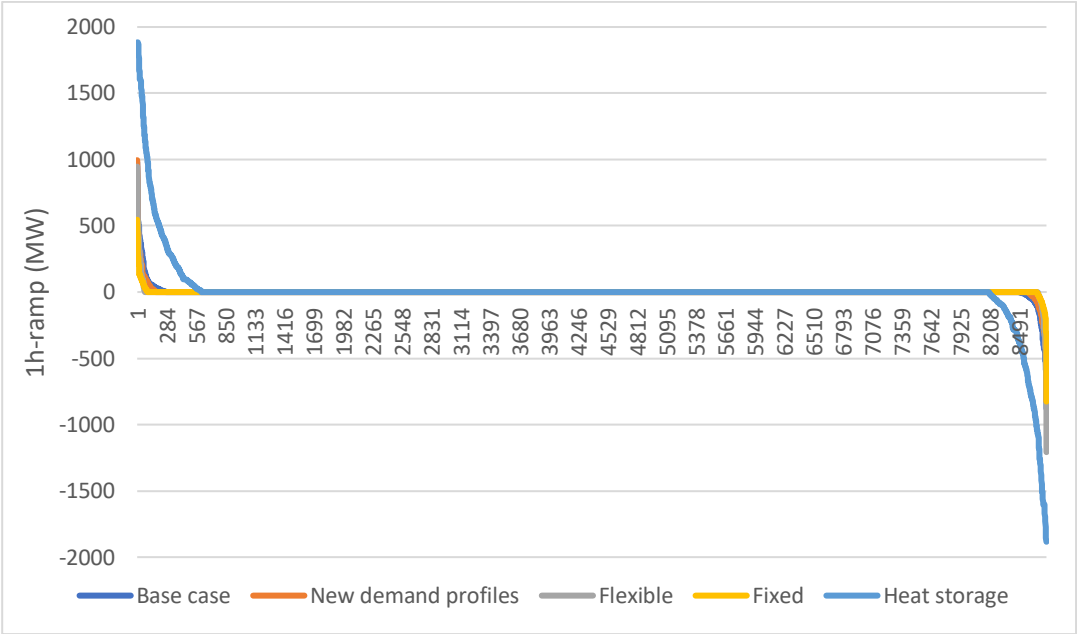
Appendix C. Overview of power-to-heat in industry (Munster et al., 2020)

	Technology	Technological readiness (1–9)	Efficiency	Cost €/kW	Description
Heat pumps	Low- to medium temperature	8–9	300–700%	250–800	Compression heat pumps using a heat source to supply process heat at temperatures up to 100°C.
	High temperature	6–7	280–360%	300–800	Compression heat pumps with mechanical vapour compression. Process heat up to 150°C.
	Very high temperature	4–6	150–200%	900–2000	Compression heat pumps with mechanical vapour compression. Process heat over 150°C. Open and closed cycle heat pumps
	Mechanical Vapour Compression	5–9	1000–3000%	1500–6500	Increasing the pressure - and thus also the temperature - of waste gases by mechanical compression. Enables the utilization of heat from waste gases.
Resistance	Indirect	8–9	98 %	70–150	Electric and electrode boilers heating an intermittent heat carrier.
	Direct	8–9	98 %	10–150	Direct heating of the material, through resistance flow heaters, electric arc furnaces and others
Electromagnetic	General	4–9	60–98%		Create heat in target material by using wavelengths in the electromagnetic spectrum e.g. infrared, microwave, radio frequency. Require less energy as they directly heat the targeted medium rather than a medium that transports the
	Infrared	6–9	98 %	143–840	
	Microwave	6–9	80 %	440	
	Induction	7–9	50–90%	41	

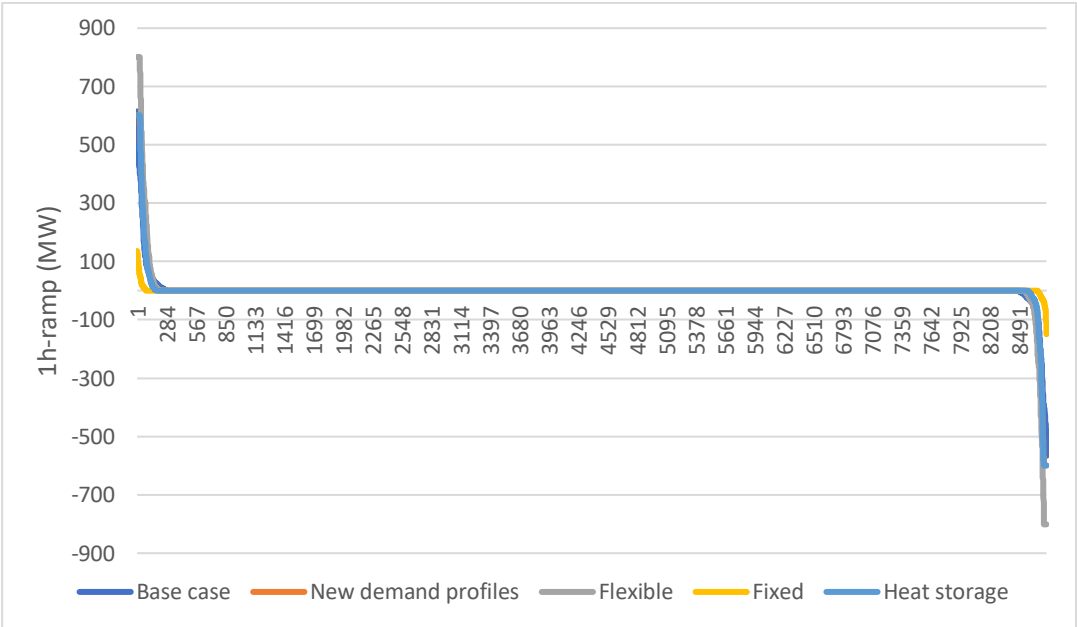
Appendix D. Electricity demand of the district heating sector with developed demand profiles and 50/50 demand allocation for DH HPs and EBs



Appendix E. Duration curves of hourly changes in electricity demand for district heating electric boilers and heat pumps in modelled cases



Appendix E, figure 1: Duration curve of hourly changes in electricity demand for district heating electric boilers



Appendix E, figure 2: Duration curve of hourly changes in electricity demand for district heating heat pumps