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Enabling cost-efficient electrification in Finland

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Foreword

The climate crisis, together with biodiversity loss, is the defining challenge of our times. To limit global heating to close to the 1.5 degrees target under the Paris Agreement, we need to achieve rapid and steep reductions in global emissions.

As stated in Prime Minister Sanna Marin's Government programme, Finland aims to be carbon neutral by 2035 and carbon negative soon after. Achieving these goals will require major changes in our society and especially in our energy system. We are about to face an unprecedented change in how we produce and use energy and other resources.

Previous Finnish energy system studies have highlighted the importance of electrifying energy use to achieve deep decarbonisation. Broadly speaking, the recipe for major emissions reductions is that first, electricity production needs to become carbon free, after which we should electrify operations in society and the economy in the order that is most efficient in terms of cost, energy, and resources.

The aim of this study is to supplement and clarify the outlook for the future of the Finnish energy system by providing a holistic view of electrification and decarbonisation in Finland. The starting point is that carbon neutrality should be reached by 2035 and full decarbonisation by 2050. We have also sought to identify key enablers and pain points for the transition and to provide recommendations for the way forward.

The starting point of the study is the current Finnish energy system, adequate security of supply and available local resources. New technological solutions such as demand flexibility as well as hydrogen and other synthetic fuels have also been taken into account.

The results show that, from an energy system perspective, achieving Finland's climate targets is possible, but it requires replacing fossil fuels with clean electricity for industry, transport and heating. Hydrogen and biomass, such as wood, can be used in applications where emissions cannot be abated through electrification.

Electricity demand is estimated to double by 2050. The study finds that the most cost-efficient source of zero-emission energy in Finland would be onshore wind, strongly supported by supply and demand side flexibility sources. These will need to be complemented with electricity storage, such as batteries and hydrogen, and the power transmission network will require strengthening.

The study demonstrates that the transition to a decarbonised energy system can be achieved. Yet, the cost efficiency of the transition is in the hands of our policy makers: to succeed in electrifying our energy system, proper frameworks need to be put in place. We need a clear vision for the future, sufficient incentives for electrification, and support for developing and adopting new technologies.

The critical issue for Finland's long-term prosperity concerns how we will succeed in the energy transition. The encouraging message of this study is that we have a fair chance to succeed. The ball is now in our policy makers' court.

Helsinki 28th September 2021

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Glossary

BECCS Bioenergy with Carbon Capture and Storage
BESS Battery electric storage system
CAPEX Capital Expenditure
CCS(U) Carbon capture and storage (and utilisation)
CHP Combined heat and power plant
CO_2 Carbon dioxide
CO_2e Carbon dioxide equivalent
DELS Direct Electrification Scenario
DSF Demand side flexibility
DSO Distribution system operator
DSR Demand side response
ENTSOE European network of transmission system operators for electricity
EV Electric vehicle
FOM Fixed Operating and Maintenance Cost
GDP Gross domestic product
GHG Greenhouse gas
GW Gigawatt, 1000 MW
GWh Gigawatt hour, 1000 MWh
LCOE Levelized Cost of Electricity
LULUCF Land Use, Land Use Change and Forestry
LVM Ministry of Transport and Communications
MAF Mid-term Adequacy Forecast
MW Megawatt
MWh Megawatt hour
OCGT Open Cycle Gas Turbine
OPEX Operating Expense
P2G2P Power-to-Gas-to-Power
POLES model used by Enerdata for full energy balance modelling (Prospective Outlook for Long-term Energy Systems)
PV Photovoltaic
PtX Power to X (i.e. Power to gas, Power to liquids, …)
PTXS Increased Power to X Scenario
RES Renewable energy source
SRMC Short run marginal costs
TEM Ministry of Economic Affairs and Employment
TSO Transmission system operator
TWh Terawatt hours, 1000 GWh
TYNDP Ten-year network development plan
VM Ministry of Finance
VOM Variable Operating and Maintenance Cost
YM Ministry of the Environment

Executive summary

Previous Finnish energy system studies – including those commissioned by Sitra – have indicated the importance of electrifying energy use to achieve deep decarbonisation. Yet, there is still much uncertainty about the structure of and the route towards a decarbonised Finnish energy system.

Aim of this study

This study provides a holistic view of electrification and decarbonisation in Finland and identifies enablers, pain points and recommendations for next steps. Carbon neutrality should be reached by 2035, in line with the national climate target, and full decarbonisation[1] by 2050.

We consider the current Finnish energy system, the required security of supply, and available local resources. In particular, newer technological solutions like demand flexibility as well as hydrogen and other synthetic fuels are considered.

Methodology

We model **two electrification scenarios** for the evolution of the Finnish energy system. The Direct Electrification Scenario assumes wide-spread direct electrification of most applications, while the Increased PtX Scenario assumes a higher uptake of indirect electrification using electricity-based hydrogen and other synthetic fuels ("power-to-X", PtX).

To achieve electrification, the **future Finnish energy demand is assessed first**. We derive projections for primary energy demand in Finland starting from estimates of population growth, as well as GDP growth in industry, services and agriculture. From these, reasonable but significant efficiency gains due to technical progress and electrification are considered. Here, electrification would generally improve overall energy efficiency. For example, electric cars have a higher efficiency compared to cars with a combustion engine.

We apply a simulation model of the European energy markets (POLES[2], from Enerdata) to simulate the **competition between technologies and fuels over time, under ever-increasing decarbonisation pressure**. Put simply, the carbon price signal that the model attaches to fossil fuels increases over time. The simulation model then gradually replaces carbon-based fuels by the most competitive non-carbon alternative.

Second, the **most cost-effective way to generate necessary electricity**, under the given yearly carbon targets is determined using the Compass Lexecon Power sector dispatch model. The cost-optimal capacity expansion is derived by **minimising the total power system costs**

1 By full decarbonisation we mean that remaining greenhouse gas emissions from agriculture, industrial processes and waste are neutralised by negative emissions, such as BECCS (bioenergy with carbon capture and storage). The Land Use, Land Use Change and Forestry (LULUCF) net sink is assumed to be on average 21.4 Mt/a throughout the period.

2 The POLES model has been initially developed by IEPE (Institute for Economics and Energy Policy), now GAEL lab (Grenoble Applied Economics Lab). The version of the model used for this report is the POLES model version owned and run by Enerdata, named POLES-Enerdata.

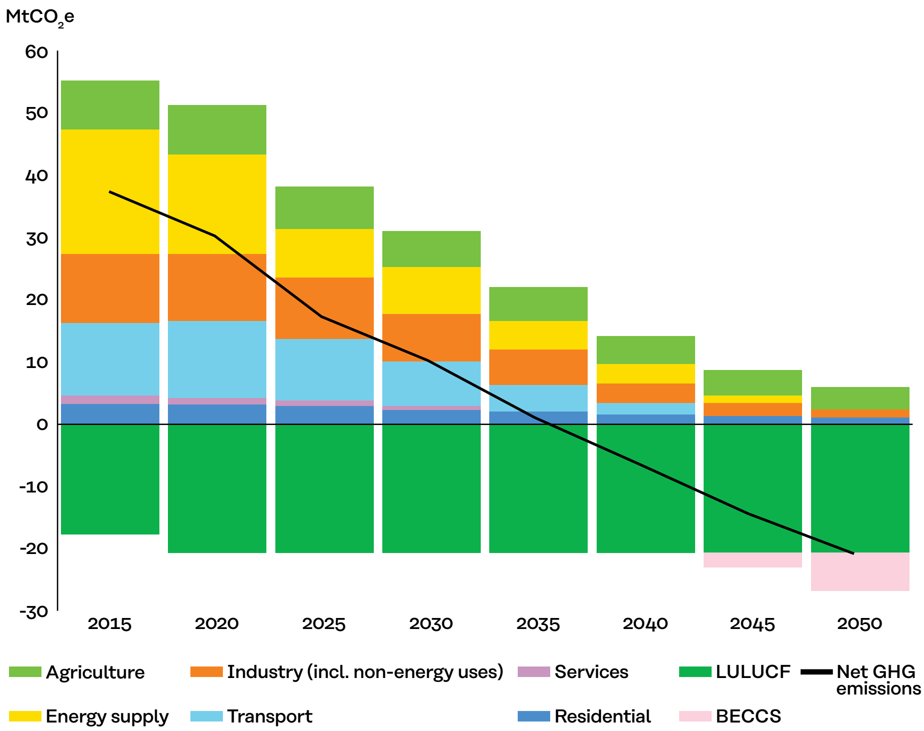
under a number of specified constraints (e.g. capacity potentials, emission limits, interconnection capacities). Assumptions and sources for these restrictions as well as other techno-economic parameters were discussed and aligned while developing the study also reflecting stakeholder feedback.[3]

In a **third step**, key **enablers and bottlenecks** were identified – also by using stakeholder workshops and interviews – acting as a basis to derive recommendations for next steps.

Future Finnish energy demand

Based on the POLES simulation, both the Finnish **GHG emissions** target of carbon neutrality by 2035, and the full decarbonisation of the energy systems by 2050 are achieved under the two scenarios. The net GHG trajectory for the Direct Electrification Scenario until 2050 is shown in Figure 1. Net GHG emissions are decreasing steadily over the 2020-2050 period, reaching almost 0 $MtCO_2e$ by 2035 and -21 $MtCO_2e$ by 2050, the assumed value of the Land Use, Land Use Change, and Forestry (LULUCF) carbon sink. In comparison to 1990 levels, gross GHG emissions are reduced by 69% in 2035 and 100% in 2050, respectively.

Figure 1: Net GHG emissions & emissions by sector, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

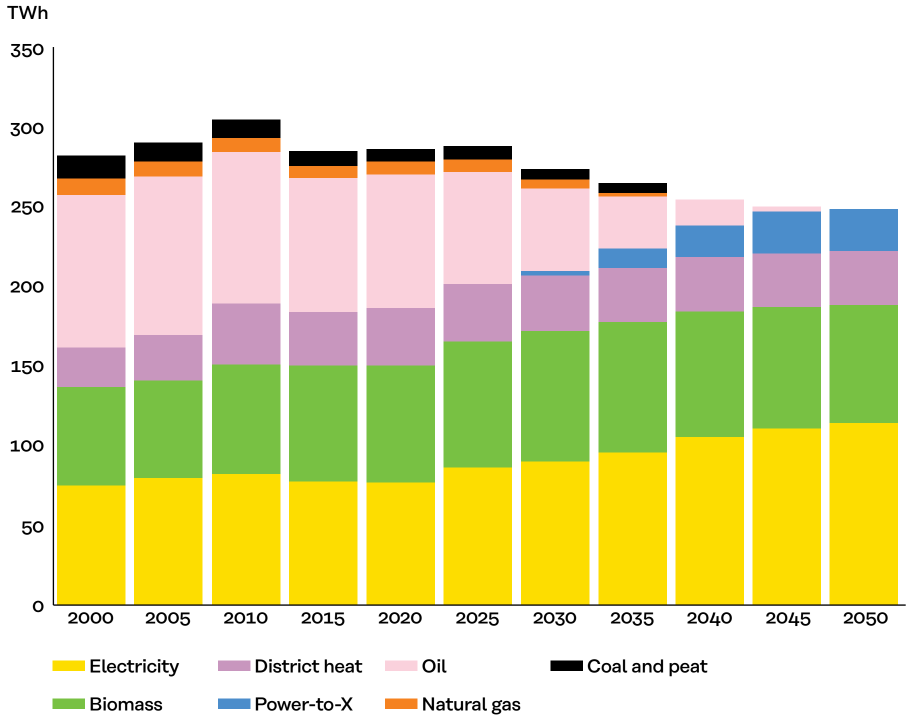
All sectors contribute to this decrease, with transport, services and energy supply reaching full decarbonisation by 2050, while residual emissions remain in some hard-to-abate sectors,

3 For example, capacity factors, which measure the overall utilization of a power-generating facility, were assumed to be 34% for new onshore wind and 47% for new offshore wind power plants.

mostly in agriculture (4 $MtCO_2e$), industrial processes (1 $MtCO_2e$) and residential waste (1 $MtCO_2e$). These remaining emissions are offset using bioenergy with carbon capture and storage (BECCS) in industrial energy consumption to reach a full decarbonisation (i.e. zero gross GHG emissions) of the systems in 2050.

As shown in Figure 2, the Finnish final energy demand slightly decreases by 2050 in the Direct Electrification Scenario, reaching about 250 TWh from 290 TWh in 2015. This decrease is mostly driven by the electrification of heating end-uses and mobility, especially through heat pumps and electric vehicles (EVs), which feature higher efficiencies compared to their alternatives. Electricity consumption is therefore growing rapidly and becomes the main energy carrier by 2050 with 46% of the final energy use (from 27% in 2015), followed by bioenergy (30%), district heat (14%) and power-to-X (11%). The Direct Electrification Scenario in particular relies on the assumed availability of sufficient sustainable and affordable biomass for energy use. In the Increased PtX-Scenario, parts of this bioenergy usage are covered by PtX-fuels instead. Overall, further analysis would be required to actually assess how much sustainable biomass there is likely to be available for energetic use.

Figure 2: Final energy consumption by fuel, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

To reach full decarbonisation of the final sectors, the consumption of fossil fuels is completely phased out by 2050 and replaced to a large extent by direct electrification of end-uses, notably through a large development of heat pumps for heating purposes and EVs in the transport sector. Bioenergy and power-to-X fuels also prove necessary for decarbonising hard-to-abate sectors, including heavy transport, some industrial processes, and chemical feedstocks.

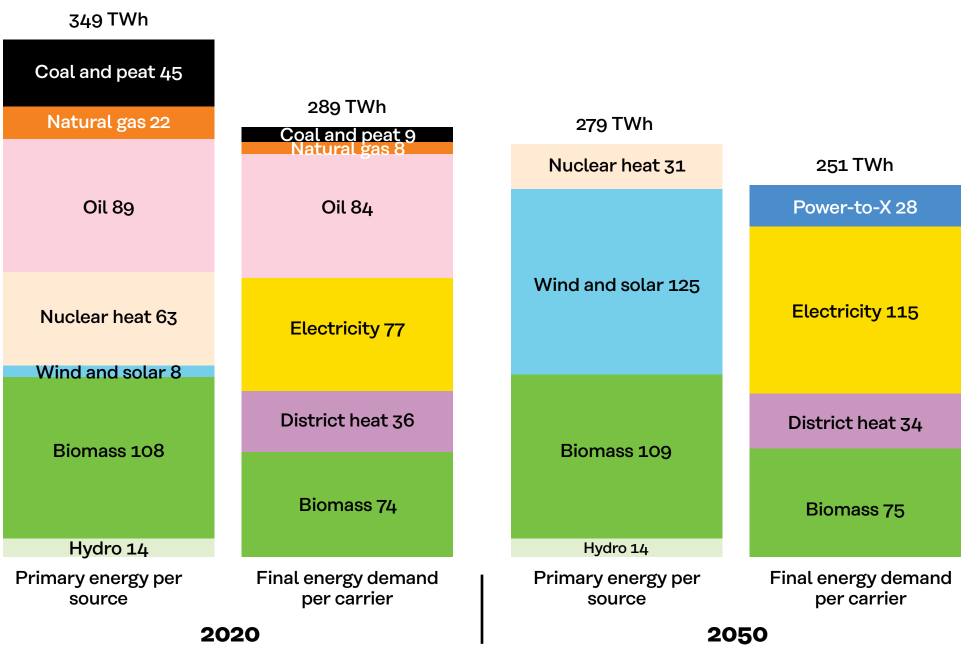
In the industrial sector, direct electrification replaces most of the fossil fuel consumption, hence electricity accounts for half of the industry energy use demand by 2050 (56 TWh of electricity out of 112 TWh in the Direct Electrification Scenario). For example, electric arc furnaces using electricity can be used in high-temperature industrial applications instead of fossil-fired furnaces. After 2030, PtX-fuels enable the full decarbonisation of hard-to-electrify industrial processes in both scenarios, notably steel reduction along with some high temperature processes. Industrial non-energy uses of fossil fuels, notably chemical feedstocks, are decarbonized using bioenergy, for example by feedstock based on pulp industry waste liquids, and power-to-X fuels, as well as increased recycling. In 2050 Power-to-X fuels account for around 15 TWh (11%) in the Direct Electrification Scenario and 30TWh (22%) in the Increased PtX Scenario for all energetic and non-energetic industrial uses.

In the transport sector, far-reaching electrification in the light transport segments – with over two thirds of the passenger car fleet being fully electric by 2050 in the Direct Electrification Scenario – leaves only limited room for vehicles with combustion engines using power-to-X fuels or biofuels. The latter two, however, remain competitive in the heavy transport segment with over 60% remaining market share by 2050. The switch to EVs, and improvements in vehicle efficiencies, significantly decrease final energy consumption in the transport sector from 49 TWh in 2015 to 34 TWh in 2050.

In buildings and services sectors, fully decarbonising the energy consumption is achieved by direct electrification (especially by the use of heat pumps in buildings and in district heating). By 2050, heat pumps represent over 90% of electricity consumed for heating purposes in the buildings sector, and more than 55% of the district heat supplied.

These demand evolutions allow both scenarios to completely replace fossil fuels in the primary energy mix by 2050. **Bioenergy** (i.e. various forms of solid, liquid, or gaseous biomass) overall plays a **substantial role in the decarbonisation**. While bioenergy usage increases in the medium-term due to its rapidly growing use for district heat, it **returns to the 2020 levels by 2050** (Figure 3).[4]

Figure 3: Primary and final energy demand 2020 and 2050 (TWh), Direct Electrification Scenario



4 It is outside the scope of this analysis to assess the availability of sustainable biomass for energetic use; this would be an important area of future analysis.

Source: POLES-Enerdata model results by Enerdata

While generally in line with the developments under the Direct Electrification Scenario, the Increased PtX Scenario arrives at more PtX-usage particularly in the industrial sector and for heavy transport. In 2050 PtX-usage adds to electricity demand for the electrolytic production of hydrogen 34 TWh in the Direct Electrification Scenario and 60 TWh in the Increased PtX Scenario, respectively.

Future Finnish energy supply

Compared to today the overall **electricity demand will grow by over 20% in 2035, and by 2050 it will double** and account for almost half of the final energy demand. This requires significant changes to the Finnish electricity system. Based on this need, this study develops cost-optimal development trajectories for electricity supply in Finland for both scenarios.

In both scenarios power generation is dominated by onshore wind generation supported by significant supply-side flexibilities

In the scenarios analysed, the power sector in Finland will undergo significant transformation with respect to its size and structure over the next 30 years. To meet increasing demand resulting from widespread electrification, Finnish **generation capacities** will more than triple by 2050, increasing from below 20 GW in 2020 to over 70 GW in the Direct Electrification Scenario (Figure 4). Over 80% of capacity additions are **onshore wind**, as sufficient potential is assumed to be available and under the aligned assumptions onshore wind generation costs remain below those of competing decarbonised generation technologies (like offshore wind or nuclear). Restricting wind build-up e.g. due to requirements of the Defence Forces or declining public acceptance issues might, however, block this route to efficient decarbonisation. Exploring options to accommodate both the Defence Force's needs and wind build-up would seem necessary.

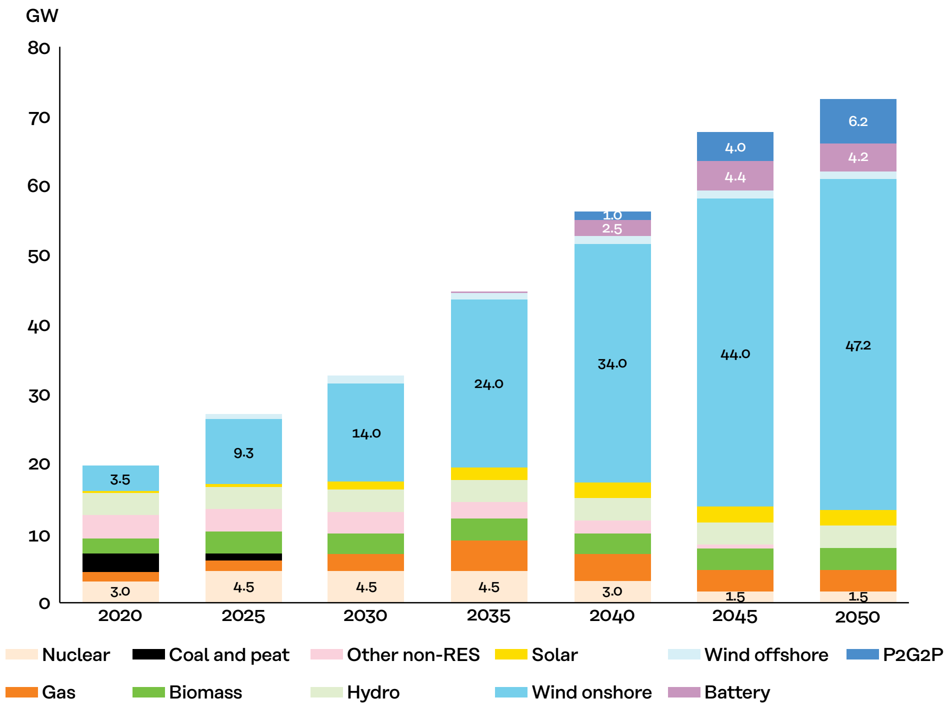
Under the defined set of assumptions including power demand outlook, cost reduction of the different technologies and renewable energy source (RES) potential, in the cost-optimal capacity mix of the Direct Electrification Scenario, **nuclear** capacity would not expand beyond Olkiluoto 3.[5] It therefore remains the only nuclear capacity in the Finnish power system after 2040, when Olkiluoto 1 and 2 and Loviisa 1 and 2 retire following their life-time extensions.[6] The life-time extensions of these plants play an important role in the outlined decarbonisation scenario. Should it become foreseeable that these will not take place, there would be an urgent need for planning alternatives to ramp-up the generation of decarbonised electricity.

The high share of wind capacities requires the deployment of significant supply-side flexibilities – **storages and peak generation** gas turbines – to ensure the integration of variable renewable generation and security of supply. Batteries ensure short-term flexibility whereas Power-to-Gas-to-Power (P2G2P) deliver longer-term – weekly and multi-weekly – storage. The importance of storages increases after closures of thermal capacities up until 2030, and again after 2040 when ageing nuclear capacities retire while onshore wind capacity continues to grow. Overall, approximately 4 GW of batteries, 6 GW of P2G2P and 3 GW of (clean) gas

5 Given the current uncertainty regarding the realisation and timing of the Hanhikivi nuclear power plant, it was not added as definitive available capacity to the study assumptions (unlike Olkiluoto 3 which was assumed to be available in 2022).
6 In the Increased PtX Scenario additional nuclear capacities are added in 2040.

peak generation capacities are included in the power generation mix in 2050. These domestic supply-side flexibilities are complemented by additional cross-border interconnectors. Potential bottlenecks for building-up supply-side flexibilities might be insufficient financial incentives to invest in technologies with very little actual generation (gas turbines) and the limited availability of storage capacities for hydrogen required for the P2G2P capacities – interconnection with European (clean) gas infrastructure might provide relief.

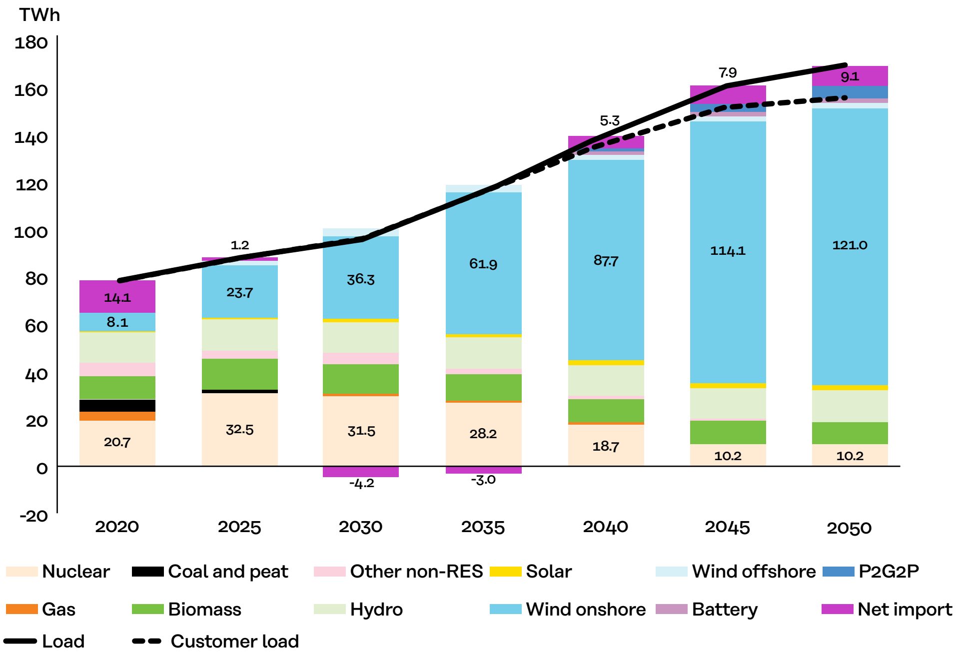
Figure 4: Installed power capacity, Direct Electrification Scenario



Note: "Other non-RES" refers to small distributed thermal units as defined by ENTSOE in the Mid-term Adequacy Forecast (MAF) and the Ten-Year Network Development Plan (TYNDP). Units with a heat capacity below 20 MW do not generally fall under the EU ETS and are therefore differently accounted for.
Source: CL power dispatch model results by Compass Lexecon

Figure 5 shows the development of power generation and demand in Finland in the Direct Electrification Scenario. Power generation becomes dominated by onshore wind from 2035 onwards reaching 73% in 2050. **Biomass** generation from CHP plants remains stable in the long-term (at approximately 10 TWh/a) but is increasing in the medium-term (up to a maximum of 14 TWh in 2025) to substitute coal and peat fired generation. Hydropower stays stable throughout the whole period generating approximately 14 TWh annually. Nuclear power generation would reach its peak in 2025, covering over a third of the annual power load in Finland but would decline to about 6% in 2050.

Figure 5: Power generation and demand (TWh), Direct Electrification Scenario

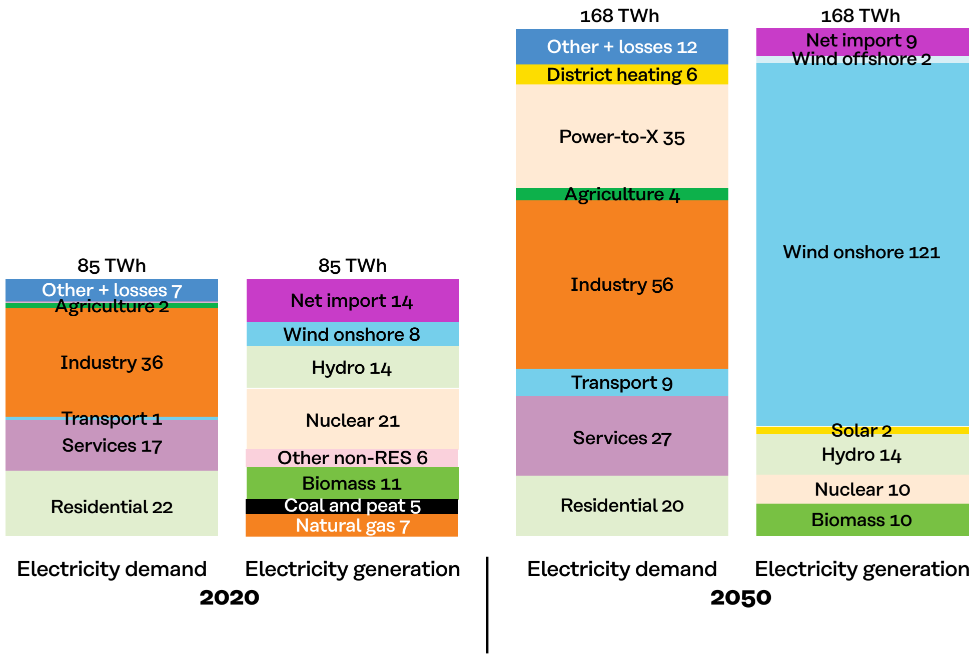


Note: "Other non-RES" refers to small distributed thermal units as defined by ENTSOE in the MAF and TYNDP; "load" refers to the total system load including the "customer load" and storage losses – mainly from P2G2P installations
Source: CL power dispatch model results by Compass Lexecon

Two important structural changes will take place under the direct electrification scenario to 2050. First, Finland will become a **temporary net exporter of electricity**. Compared to the current net import of about a fifth of the Finnish annual consumption, between 2030 and 2035 Finland exports 3-4 TWh of surplus generation annually. The main reasons are increasing nuclear capacities in the short-term (Olkiluoto 3) and the rapid growth of onshore wind generation. However, from 2040 onwards, Finland would return to be a net importer, due to increasing power demand and the decommissioning of large nuclear capacities. Throughout this time, the flexibility from the Nordic hydro (Norway and Sweden) and nuclear generation (Sweden) available to the Finnish System via interconnection capacities would play an important role in integrating Finnish wind generation. The second structural shift is represented by the increasing **divergence between the system load and the customer load**, as shown in Figure 5 and becoming pronounced from 2040 onwards. The system load would become increasingly higher than the customer load. The difference grows up to almost 14 TWh in 2050 and is mainly driven by the efficiency losses of the P2G2P conversion process used for longer term energy storage.

The overall transition in the power sector is summarised in Figure 6.

Figure 6: Sectoral electricity demand and electricity generation 2020 and 2050 (TWh), Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata and CL power dispatch model results by Compass Lexecon

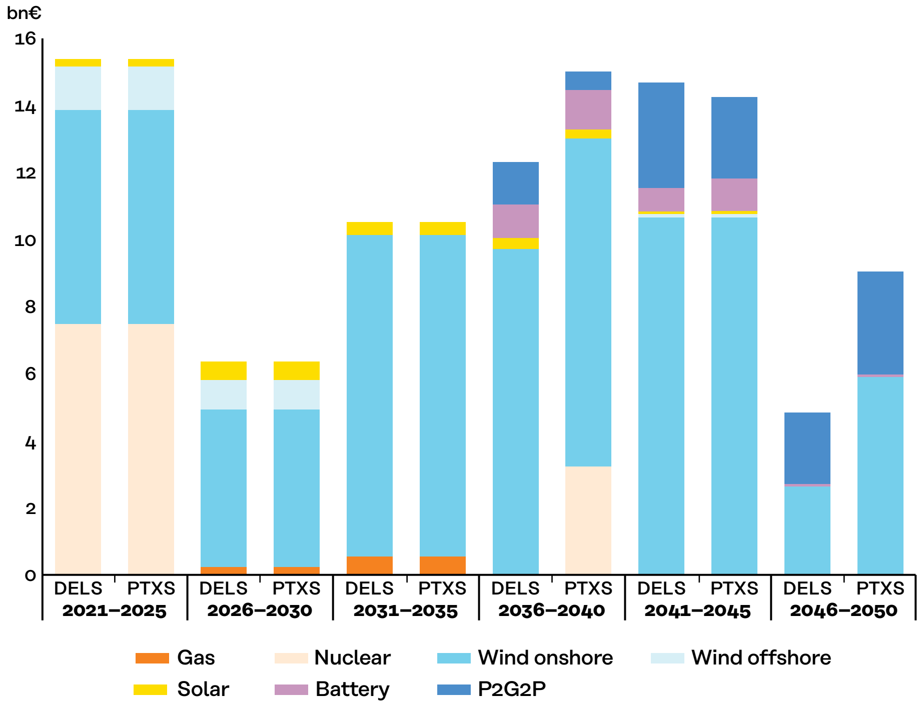
From a network perspective, strong electrification will mainly impact the **transmission** network, increasing the need for transmission capacity expansion, particularly to connect wind generation sites to demand centres. Moreover, the scenarios assume a significant build-up of interconnection capacities (+1.5 GW by 2035 and +5.8 GW by 2050). The impact of strong electrification on **distribution** networks is expected to lead only to limited capacity expansion needs.

Significant investments will be required to expand the electricity system in line with the requirements of the strong electrification scenarios analysed

The investments required for the transformation of the Finnish electricity system were estimated on the basis of both scenarios. For the build-up of Finnish **generation and storage capacities** the derived optimal capacity expansions were therefore valued with specific investment assumptions in line with the European Commission's Technology Pathways study (EC, 2018; Capros, et al., 2019) – thereby factoring in cost decreases up until 2050. The results are estimates of investments[7] up until 2050 of about 64 billion $€_{2020}$ in the Direct Electrification Scenario and about 70 billion $€_{2020}$ in the Increased PtX Scenario (undiscounted sums). The by far biggest share of investment in both scenarios (almost 70%) is thereby directed towards onshore wind capacity expansion (Figure 7).

7 In this study all monetary figures are expressed in real terms; the subscripted number following the currency indicator specifies the base year.

Figure 7: CAPEX per technology (bn€$_{2020}$, non-discounted sums), Direct Electrification (DELS) and Increased PtX (PTXS) Scenarios



Note: Investment into nuclear capacity in 2021-2025 represents Olkiluoto 3 and the timing is matched with the expected start of commercial operation (i.e. 2022)
Source: CL power dispatch model results by Compass Lexecon

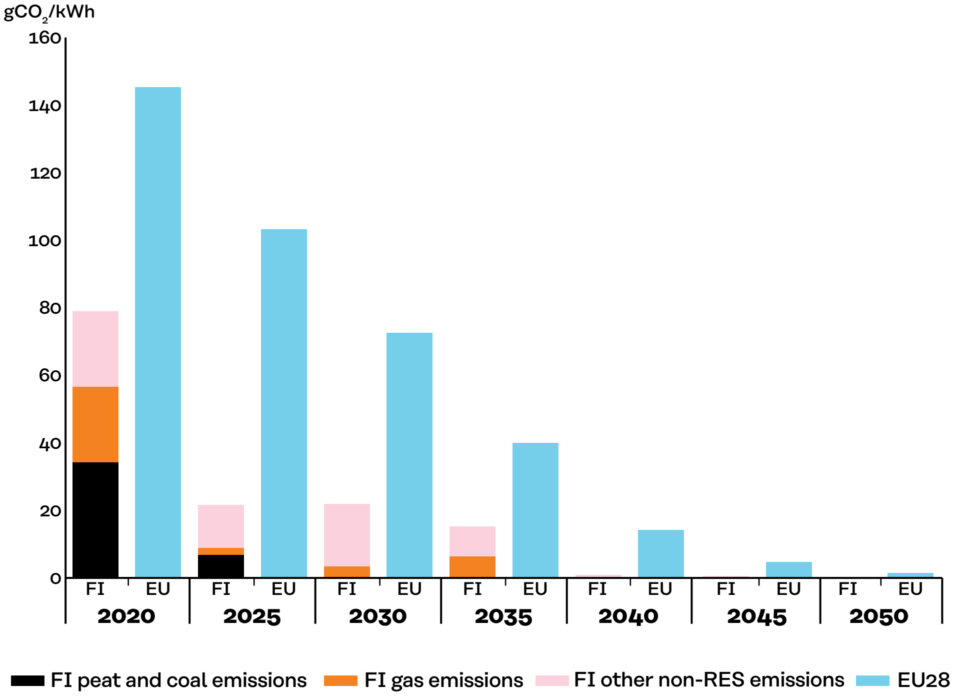
Based on Fingrid (2021) scenarios, investment needs in the **domestic transmission network** required (beyond Fingrid's current 2 billion €$_{2020}$ plan) to accommodate additional demand and generation in line with the two scenarios were estimated to be between 1.5 and 3 billion €$_{2020}$ over 2020 to 2050 (undiscounted sums). Besides, additional investment of about 0.9 billion €$_{2020}$ for years 2020–2035 and about 2.6 billion €$_{2020}$ for years 2035–2050 (undiscounted sums) would be required for the expansion of **interconnection capacities** in line with the scenario assumptions.

Large scale electrification is not expected to require additional **distribution grid investments** as capacity expansions would generally be covered by regularly required renewal and upgrade investments.

Electricity sector emissions

Both scenarios would almost eliminate electricity sector CO_2 emissions already by 2040. The Finnish CO_2 reduction trajectory in both scenarios would thereby be well ahead of the EU average (Figure 8). While the scenario arrives at relatively stable specific emissions (gCO_2/kWh) between 2025 and 2030, the generation of decarbonised electricity increases by almost a third (Figure 8).

Figure 8: Carbon content of Finnish and European electricity (gCO_2/kWh), Direct Electrification Scenario

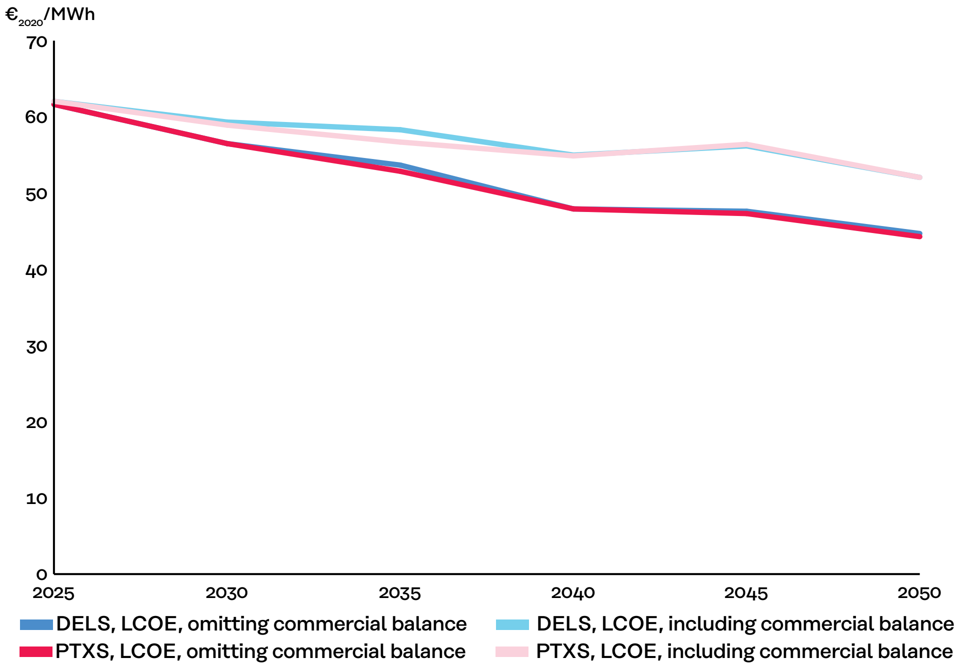


Source: CL power dispatch model results by Compass Lexecon

Cost and prices

In both scenarios overall electricity production costs in Finland (LCOE) would decline by almost 30% in 2050 compared to 2020. When factoring in imports, cost of electricity consumed in Finland in 2050 still declines by 20% compared to today (Figure 9).

Figure 9: Total power system cost per MWh, LCOE, (€$_{2020}$/MWh/year)

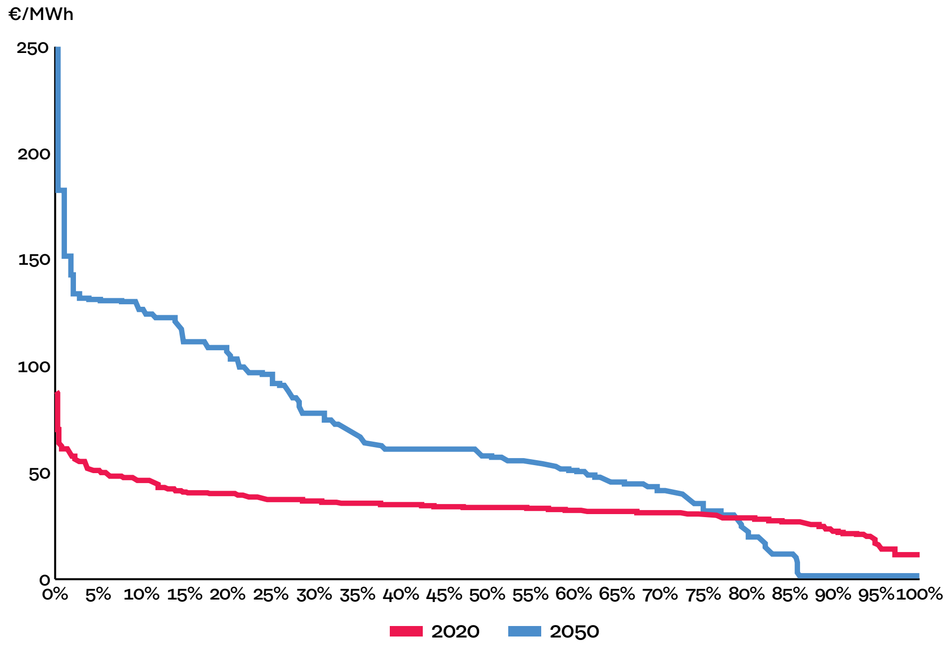


Notes: LCOE refers to levelized cost of electricity (i.e. capital costs, operating and maintenance costs and fuel costs where applicable divided by annual generation volumes; taxes and carbon (ETS) costs are not included). Commercial balance is the value or cost of net imports or net exports.
Source: CL power dispatch model results by Compass Lexecon

Higher intermittent renewable penetration will change the Finnish wholesale power price[8] dynamics. The number of hours with high but also low to zero prices compared to today will increase significantly (Figure 10) thereby raising the annual average[9] real wholesale power price by about 86% in 2050 compared to today.

8 That is, the price of electricity on electricity markets. This price is generally set by considering the variable generation costs of the marginal generation unit required to meet demand in a specific hour. The marginal cost-based wholesale price generally differs from the average full costs of electricity generation expressed in the LCOE.
9 That is, the average over all 8,760 hours of the year thereby disregarding actual consumer load patterns and the effects of demand side flexibility avoiding offtake during the most expensive hours.

Figure 10: Wholesale Price Duration Curves in the Direct Electrification Scenario (€/MWh)



Source: CL power dispatch model results by Compass Lexecon

From an end-user perspective, increased usage of electricity – and associated costs – are balanced by reduced overall energy usage due to efficiency gains and electrification reducing fossil fuel usage.

Two sensitivity analyses explore the effects of restrictions on wind build-up and the availability of demand-side flexibility

The first sensitivity focuses on **onshore wind potentials** and limits them to 25 GW (instead of the max. 54 GW in the baseline assumption). This shifts the cost-optimal generation capacity mix in the Direct Electrification Scenario significantly towards more nuclear capacities (+4.5GW by 2050) and batteries while reducing longer-term P2G2P storage as longer-term flexibility is provided by nuclear generation. Increased imports lead to slightly reduced Finnish domestic system costs, but the total costs increase compared to the baseline scenario once factoring-in these imports.

The second sensitivity analysis focuses on the uptake of **demand side flexibility** (DSF) by almost halving the potential compared to the baseline assumptions. This reduced DSF availability increases the need for supply-side flexibility (storage) as well as additional generation capacities to cover storage losses – all leading to significantly increased overall system and electricity costs. The limited availability of gas storage capacities and suitable sites in Finland underlines the importance of using DSF up to their full potential. Additional incentives and information as well as broad deployment of respective digitalisation solutions might be required to ensure that DSF potentials are actually made available.

Conclusions and next steps

Achieving the ambitious climate and energy targets (carbon neutrality in 2035 and full decarbonisation in 2050) is possible with envisaged technologies, without overly optimistic energy efficiency gains or sustained increase of biomass usage compromising the carbon sink of Finnish forests. Instead, strong direct and indirect electrification across the economic sectors would avoid most of the historical greenhouse gas (GHG) emissions. The remaining GHG emissions from agriculture, industrial processes, and waste in 2050 would be compensated by negative emissions from the deployment of bioenergy with carbon capture and storage (BECCS).

The role of indirect electrification using electricity-based hydrogen and other synthetic fuels ("power-to-X", PtX) in the future energy system of Finland is specifically studied here. We show that PtX fuels can be competitive in the heavy transport segment, and in industry PtX can enable full decarbonisation of hard-to-electrify industrial processes. Industrial non-energy uses, notably chemical feedstocks, can be decarbonised using bioenergy, for example feedstock based on industry waste liquids, and power-to-X fuels, as well as increased recycling.

The study finds that the major cost-efficient source of decarbonised power in Finland under the specified scenarios would be onshore wind, strongly supported by supply and demand side flexibility sources. We establish that not developing the full economic potential of onshore wind or demand side flexibility has large and costly consequences for the Finnish power system. Significant new domestic supply-side flexibilities will be required to balance the increasing intermittent wind generation and replace retired fossil generation. Specifically, power-to-gas-to-power (P2G2P) capacities could provide weekly and longer-term flexibility and batteries could provide intraday flexibility to balance wind generation, especially from 2040 onwards.

Electrification would also strongly impact the transmission network, increasing the need for transmission capacity expansion. Distribution networks would need only a limited capacity expansion, but peak demand management would become essential.

In both scenarios the overall electricity production costs in Finland (LCOE) would decline by almost 30% in 2050 compared to today. Lastly, the study shows that the increased usage of electricity – and associated costs – would be balanced by efficiency gains and electrification reducing fossil fuel usage.

We identify several important **next steps** on enabling the cost-efficient decarbonisation in Finland based on the findings using quantitative modelling and qualitative analysis as well as stakeholder engagement. For industry, options for implementing needed incentives for carbon neutral processes and feedstock on the national and EU-level should be explored. Schemes for incentivising negative emissions should be analysed and the corresponding market established on the national or EU-level. A favourable and competitive investment environment for industrial actors aiming for decarbonising investments should be ensured, and including rapid permitting and predictable regulation. Broad EU-level regulatory framework supporting the build-up of a hydrogen industry in Finland, including infrastructure, should be developed. Finland should also develop a clear national hydrogen strategy.

Wind power will play a significant role in the future Finnish power mix. Measures to structurally reduce the impact of the Finnish Defence Forces' requirements on the build-up of wind generation capacities should be explored, for example, by defining areas with military restrictions on wind build-up in advance, more transparent discussions on building plans, and research and development of solutions to limit interference between army radars and wind turbines. Also measures to reduce the length of permitting processes for wind parks (such as potentially increasing public administration permitting capacity or courts' resources to handle complaints) should be explored. To ensure future availability of supply and demand side flexibilities, the sufficiency of investment incentives should be regularly reviewed, and if necessary, options to improve these incentives should be explored.

Inherent in any forward-looking study and any modelling approach also the present work has **limitations and uncertainties,** which are often related to the underlying assumptions. For example, if the energy efficiency gains due to technical progress and electrification do not materialise, this would lead to higher future final energy demand and slower pace of decarbonisation and different energy balance. Similarly, if the future technology costs deviate significantly from the assumptions used here – for instance regarding offshore wind or nuclear power – this may lead to changes in the cost-efficient energy mix and the decarbonisation pathway. Deviations in availability and costs of sustainable biomass for energy uses may equally result in a significant variation to the decarbonisation pathway. These current uncertainties should be monitored and impacts of any significant deviations from the current state-of-the-art assumptions should be further analysed. **Future research** should carefully evaluate the technical regulation and policy design concerning strategic infrastructure to ensure cost-efficient and secure energy supply in Finland.

Tiivistelmä

Aikaisemmat Suomen energiajärjestelmään keskittyneet selvitykset – mukaan lukien Sitran tilaamat – ovat osoittaneet energiankulutuksen sähköistämisen tärkeyden päästöjen vähentämisessä. On kuitenkin yhä epävarmaa, kuinka päästötön energiajärjestelmä olisi saavutettavissa ja mikä olisi sen rakenne Suomessa.

Selvityksen tavoitteet

Selvityksen tavoitteena on antaa kokonaisvaltainen kuva sähköistämisestä ja päästöjen vähentämisestä Suomessa sekä tunnistaa eri mahdollistajat, kipupisteet ja suositukset seuraavia vaiheita varten. Tarkastelun lähtökohtana on, että hiilineutraalius saavutetaan vuoteen 2035 mennessä ja päästöttömyys[1] vuoteen 2050 mennessä.

Selvityksen lähtökohtana ovat Suomen nykyinen energiajärjestelmä, riittävä toimitusvarmuus ja saatavilla olevat resurssit. Työssä on huomioitu myös uudemmat teknologiset ratkaisut, kuten kysyntäjousto, vety ja synteettiset polttoaineet.

Metodologia

Selvityksessä on mallinnettu **kaksi sähköistämisskenaariota**. Suoran sähköistämisen skenaario olettaa laajaa suoraa sähköistymistä useissa käyttökohteissa. Lisääntynyt PtX -skenaario olettaa laajamittaisempaa epäsuoraa sähköistymistä, joka perustuu vetyyn ja muihin synteettisiin polttoaineisiin (power-to-X, PtX).

Energiajärjestelmän sähköistämistä on lähestytty ensin **määrittämällä Suomen tulevaisuuden energiankulutus**. Mallinnetuissa skenaarioissa Suomen tulevaisuuden primäärienergiatarve on laskettu käyttäen väestöennusteita sekä teollisuuden, palvelujen ja maatalouden talouden kasvuennusteita. Teknologian kehittymisen ja sähköistymisen on oletettu tuovan merkittävät mutta realistiset parannukset energiatehokkuuteen. Esimerkiksi sähköautoilla on polttomoottoriautoja korkeampi hyötysuhde.

Eurooppalaisen energiamarkkinan simulointimallia (Enerdatan POLES-malli[2]) on käytetty **kuvaamaan kilpailua eri teknologioiden ja polttoaineiden** väl**illä päästö**t**avoitteiden kiristyessä**. Malli asettaa ajan myötä kasvavan hiilidioksidin hinnan, minkä myötä fossiilisia polttoaineita korvataan vähitellen kilpailukykyisimmillä päästöttömillä vaihtoehdoilla.

Käyttämällä Compass Lexeconin sähkömarkkinamallia on tämän jälkeen **määritetty kustannustehokkain tuotantomuotojen yhdistelmä, jolla voidaan tuottaa vaadittu sähköenergia** täyttäen asetetut päästövaatimukset ja muut rajoitukset (esimerkiksi tuotantopotenti-

1 Päästöttömyydellä tarkoitetaan maataloudesta, teollisuusprosesseista ja jätteistä jäljelle jäävien kasvihuonekaasujen kompensointia negatiivisia päästöjä tuottavilla ratkaisuilla, kuten hiilen talteenotolla ja varastoinnilla bioenergiaan yhdistettynä (BECCS). Maankäytön, maankäytön muutoksen ja metsätalouden (LULUCF) nettohiilinielun on oletettu olevan keskimäärin 21,4 Mt/v. tarkasteltavan ajanjakson aikana.

2 POLES-malli on alun perin IEPE:n (Institute for Economics and Energy Policy), nykyisin GAELin (Grenoble Applied Economics Lab) kehittämä. Tässä selvityksessä käytetty versio mallista on Enerdatan omistama POLES-Enerdata.

aalit, rajasiirtoyhteyksien kapasiteetti). Eri oletuksista, kuten rajoituksista ja muista teknis-taloudellisista reunaehdoista, on keskusteltu ja niissä on huomioitu muun muassa sidosryhmien palaute.[3]

Tämän jälkeen **on tunnistettu pääasialliset mahdollistajat ja pullonkaulat** käyttämällä muun muassa sidosryhmien työpajoja ja haastatteluja. Näiden perusteella on laadittu suositukset seuraavista vaiheista.

Suomen tulevaisuuden energiantarve

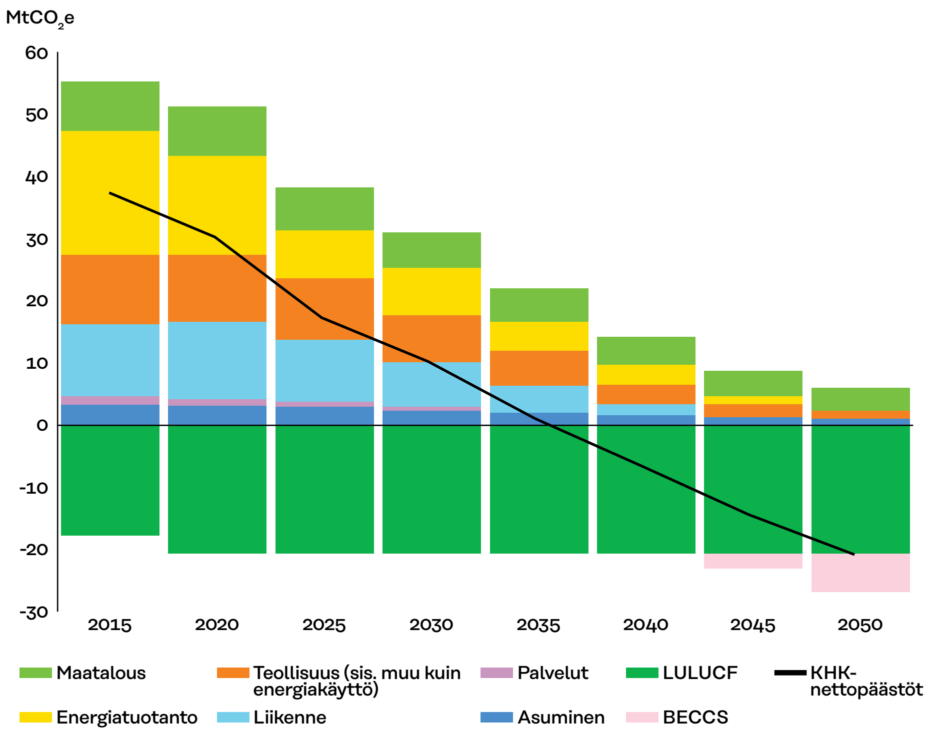
POLES-mallin simulointituloksien perusteella **Suomi voi saavuttaa kummassakin skenaariossa tavoitteet hiilineutraaliudesta vuoteen 2035 ja päästöttömyydestä vuoteen 2050 mennessä**. Suoran **sähköistämi**sen skenaariossa nettopäästöt laskevat tasaisesti 2020–2050 saavuttaen lähes 0 MtCO_2e vuoteen 2035 mennessä ja –21 MtCO_2e vuoteen 2050 mennessä, mikä vastaa oletettua maankäytön, maankäytön muutoksen ja metsätalouden (LULUCF) hiilinielua (Kuva 1). Verrattuna vuoden 1990 tasoon bruttopäästöt laskevat 69 prosenttia vuoteen 2035 mennessä ja 100 prosenttia vuoteen 2050 mennessä.

Eurooppalaisen energiamarkkinan simulointimallia (Enerdatan POLES-malli) on käytetty **kuvastamaan kilpailua eri teknologioiden ja polttoaineiden välillä hiilestä irtautumisen tavoitteiden kiristyessä**. Malli asettaa fossiilisille polttoaineille ajan myötä kasvavan CO_2-hinnan, minkä myötä fossiilisia polttoaineita korvataan vähitellen kilpailukykyisimmillä päästöttömillä vaihtoehdoilla.

POLES-mallin simulointituloksien perusteella **Suomi voi saavuttaa kummassakin skenaariossa asetetut tavoitteet hiilineutraaliudesta vuoteen 2035 mennessä ja täyden hiilestä irtautumisesta vuoteen 2050 mennessä.** Kasvihuonekaasujen (KHK) nettopäästöjen kehitystä Suoran Sähköistämisen Skenaariossa on kuvattu vuoteen 2050 asti (Kuva 1). KHK nettopäästöt laskevat tasaisesti 2020–2050, saavuttaen lähes 0 MtCO_2e vuoteen 2035 mennessä ja -21 MtCO_2e vuoteen 2050 mennessä, mikä vastaa oletettua maankäytön, maankäytön muutoksen ja metsätalouden (LULUCF) hiilinielua. Verrattuna vuoden 1990 tasoon, KHK bruttopäästöt laskevat 69% vuoteen 2035 mennessä ja 100% vuoteen 2050 mennessä.

3 Esimerkiksi kapasiteettikerroin, joka kuvastaa voimalaitoksen käyttöastetta, oletettiin olevan 34 prosenttia uusille maatulivoimaloille ja 47 prosenttia uusille merituulivoimaloille.

Kuva 1: Kasvihuonekaasujen nettopäästöt ja päästöt sektoreittain suoran sähköistämisen skenaariossa

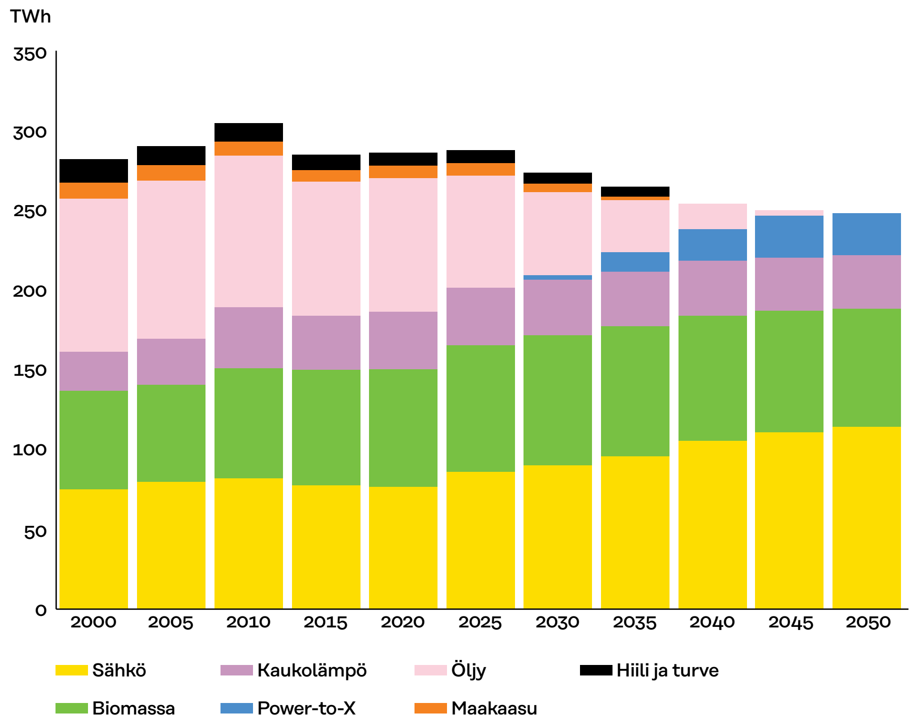


Lähde: Enerdatan POLES-mallin tulokset

Kaikki sektorit osallistuvat päästövähennyksiin, ja liikenne, palvelut ja energiantuotanto ovat päästöttömiä vuoteen 2050 mennessä. Maatalous (4 $MtCO_2e$), teollisuuden prosessit (1 $MtCO_2e$) ja kotitalousjätteet (1 $MtCO_2e$) synnyttävät vaikeasti vähennettäviä päästöjä vielä vuonna 2050. Jäljelle jäävät päästöt kompensoidaan käyttämällä teollisuudessa bioenergiaan yhdistettyä hiilen talteenottoa ja varastointia (BECCS), jotta voidaan saavuttaa päästöttömyys (bruttopäästöt ovat nollassa) vuonna 2050.

Suomen energian loppukäyttö pienentyy hieman vuoden 2015 tasosta (290 TWh) vuoteen 2050 mennessä (noin 250 TWh) (Kuva 2). Etenkin lämmityksen (lämpöpumput) ja liikenteen (sähköautot) sähköistäminen pienentävät energian loppukäyttöä parantuneen hyötysuhteen ansiosta. Samalla sähkönkulutus kasvaa nopeasti, ja sähkö onkin pääasiallinen energiankantaja vuonna 2050 kattaen noin 46 prosenttia energian loppukäytöstä (27 % vuonna 2015). Bioenergia (30 %), kaukolämpö (14 %) ja power-to-X (11 %) kattavat jäljelle jäävän osuuden energian loppukäytöstä. Etenkin suoran sähköistämisen skenaario pohjautuu vahvasti oletukseen edullisen ja kestävän bioenergian riittävästä saatavuudesta. Lisääntynyt PtX -skenaariossa osa bioenergian käytöstä korvataan synteettisillä polttoaineilla. Lisätutkimusta vaadittaisiin selvittämään, kuinka paljon kestävää biomassaa olisi todellisuudessa käytettävissä energiaksi.

Kuva 2: Energian loppukäyttö polttoaineittain suoran sähköistämisen skenaariossa



Lähde: Enerdatan POLES-mallin tulokset

Jotta voidaan saavuttaa päästötön energiajärjestelmä, täytyy loppukulutuksessa luopua täysin fossiilista polttoaineista vuoteen 2050 mennessä ja ne täytyy korvata pääasiassa suoralla sähköistämisellä, etenkin merkittävällä lämmityksen siirtymisellä lämpöpumppuihin ja liikenteen siirtymisellä sähköautoihin. Bioenergia ja power-to-X-ratkaisut (kuten synteettiset polttoaineet) osoittautuvat myös tärkeiksi – etenkin käyttökohteissa, joissa päästöjen vähentäminen on muuten vaikeaa, kuten raskas liikenne, osa teollisuusprosesseista ja kemianteollisuuden raaka-aineet.

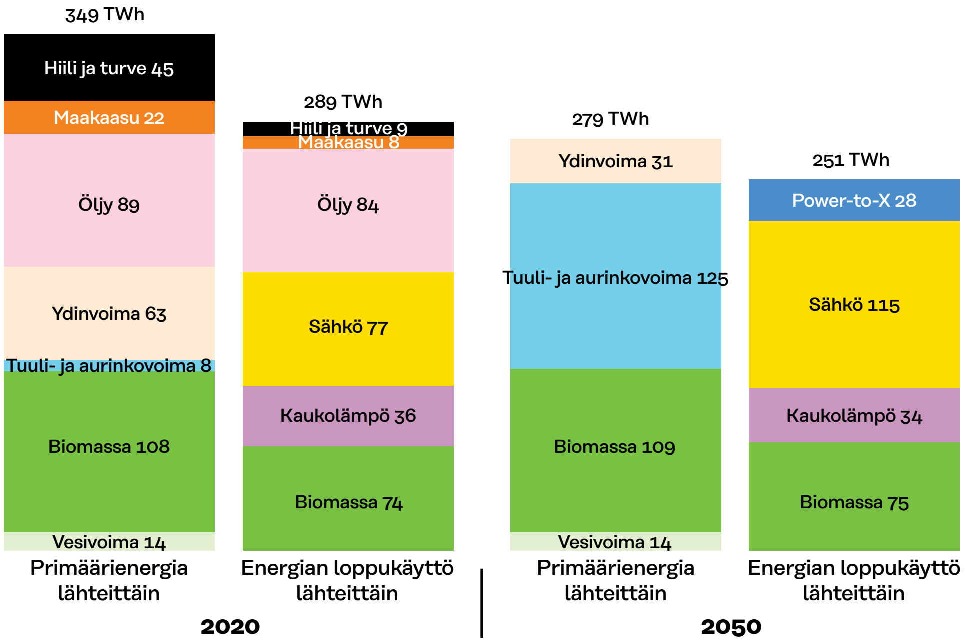
Teollisuudessa suora sähköistäminen korvaa suuren osan fossiilisten polttoaineiden kulutuksesta. Sähkö kattaakin suoran sähköistämisen skenaariossa vuonna 2050 teollisuuden energian loppukäytöstä puolet (56 TWh sähköä, energian loppukäyttö kokonaisuudessaan 112 TWh). Esimerkiksi korkeita lämpötiloja vaativissa teollisuusprosesseissa sähköistä valokaari-uunia voidaan käyttää fossiilisia polttoaineita käyttävän uunin sijaan. Vuoden 2030 jälkeen kummassakin skenaariossa PtX-polttoaineet mahdollistavat päästöjen vähentämisen vaikeasti sähköistettävissä prosesseissa, etenkin raudan pelkistyksessä ja joissain korkeaa lämpötilaa vaativissa prosesseissa. Teollisuudessa fossiilisten polttoaineiden muuta kuin energiakäyttöä (esimerkiksi kemianteollisuuden raaka-aineet) voidaan korvata biomassalla, esimerkiksi metsäteollisuuden raaka-aineista syntyvillä sivuvirroilla ja power-to-X-ratkaisuilla sekä lisääntyneellä kierrätyksellä. Vuonna 2050 power-to-X-ratkaisut kattavat kaikesta teollisuuden energia- ja raaka-ainekäytöstä 15 TWh (11 %) suoran sähköistämisen skenaariossa ja 30 TWh (22 %) lisääntynyt PtX -skenaariossa.

Liikenne sähköistyy laajasti, mikä näkyy etenkin henkilöautoissa. Henkilöautoilusta kaksi kolmasosaa on täysin sähköistetty vuoteen 2050 mennessä suoran sähköistämisen skenaariossa ja loppuosa henkilöautoista käyttää joko synteettisiä tai biopolttoaineita. Raskaassa liikenteessä synteettisten ja biopolttoaineiden rooli on kuitenkin selvästi korkeampi kattaen noin 60 prosenttia kaikesta kulutuksesta vuonna 2050. Suoran sähköistämisen skenaariossa sähköistyminen ja ajoneuvojen parantunut hyötysuhde laskevat selvästi energian loppukäyttöä liikenteessä 49 TWh:sta vuonna 2015 34 TWh:iin vuonna 2050.

Rakennuksissa ja palveluissa suora sähköistäminen (etenkin lämpöpumput rakennuksissa ja kaukolämpöverkossa) on pääasiallinen keino saavuttaa päästöttömyys. Vuonna 2050 lämpöpumput kattavat yli 90 prosenttia kaikesta lämmitykseen käytetystä sähköstä rakennussektorilla ja yli 55 prosenttia kaukolämpöverkkoon syötetystä energiasta.

Kuvatut energiankulutuksen kehityssuunnat mahdollistavat kummassakin skenaariossa täydellisen fossiilisten polttoaineiden korvaamisen vuoteen 2050 mennessä. **Bioenergialla** (kiinteänä, nesteenä ja kaasuna) **on merkittävä rooli päästöttömyydessä**. Vaikka bioenergian käyttö kasvaa keskipitkällä aikavälillä muun muassa kaukolämmössä, **vastaa vuoden 2050 käyttö vuoden 2020 tasoa** (Kuva 3)[4].

Kuva 3: Primäärienergia ja energian loppukäyttö vuonna 2020 ja 2050 (TWh) suoran sähköistämisen skenaariossa



Lähde: Enerdatan POLES-mallin tulokset

Lisääntynyt PtX -skenaario on yleisesti ottaen linjassa suoran sähköistämisen skenaarion kanssa, mutta power-to-X-ratkaisujen käyttö kasvaa enemmän etenkin teollisuudessa ja raskaassa liikenteessä. Vuonna 2050 vedyn tuotanto kasvattaa sähkönkulutusta 34 TWh suoran sähköistämisen skenaariossa ja 60 TWh lisääntynyt PtX -skenaariossa.

4 Selvityksen ulkopuolelle jää energiakäyttöä varten kestävästi saatavilla olevan biomassan saatavuuden arviointi.

Suomen tulevaisuuden energiantuotanto

Verrattuna nykytilanteeseen **sähkönkulutus kasvaa yli 20 prosenttia vuoteen 2035 ja tuplaantuu vuoteen 2050 mennessä**. Tämänkaltainen kasvu vaatii merkittävää muutosta Suomen sähköntuotannossa. Selvityksessä on mallinnettu kummallekin sähkönkulutuksen skenaariolle kustannustehokas sähköntuotannon kehitys.

Sähköntuotantokapasiteetin muutokset

Skenaarioissa Suomen sähköntuotanto muuttuu seuraavan 30 vuoden aikana merkittävästi niin määrältään kuin rakenteeltaan. Jotta sähköistymisestä johtuvaan kasvavaan kulutukseen voidaan vastata, **sähköntuotantokapasiteetti** kasvaa yli kolminkertaiseksi vuoteen 2050 mennessä. Vuonna 2020 kapasiteetti oli alle 20 GW, ja suoran sähköistämisen skenaariossa se kasvaa yli 70 GW:iin (Kuva 4). Yli 80 prosenttia kapasiteetin lisäyksestä on **maatuulivoimaa**, sillä sen tuotantokustannus on muita hiilivapaita tuotantomuotoja (kuten ydinvoima tai merituulivoima) alhaisempi ja sen tuotantopotentiaali on riittävä. Jos tuulivoiman rakentamista rajoitettaisiin esimerkiksi puolustusvoimien asettamien rajoituksien tai heikon hyväksyttävyyden takia, se estäisi päästöjen vähentämisen kustannustehokkaimmalla tavalla. Keinoja tyydyttää puolustusvoimien tarpeet ja mahdollistaa tuulivoiman rakentaminen yhtä aikaa täytyy tutkia lisää.

Valitut oletukset (kuten sähkönkysynnän kasvuennusteet, teknologioiden hinnankehitykset ja uusiutuvien energiantuotantomuotojen potentiaalit) johtavat tilanteeseen, jossa suoran sähköistämisen skenaarion kustannusoptimoidussa sähköntuotannossa ei ole uusia **ydinvoimaloita** Olkiluoto 3:n jälkeen[5]. Näin se on ainoa jäljellä oleva ydinvoimala Suomessa vuoden 2040 jälkeen, kun Olkiluoto 1 ja 2 sekä Loviisa 1 ja 2 lopettavat toimintansa niiden oletettujen jatkolupakausien päätyttyä[6]. Oletukset nykyisten ydinvoimaloiden jatkoluvista ja toiminnan jatkamisesta ovat tärkeässä roolissa. Jos nämä oletukset eivät toteudu, vaihtoehtoisia tuotantomuotoja tarvittaisiin hyvin nopeasti lisää.

Tuulivoiman kattaessa huomattavan osuuden tuotannosta tarvitaan myös merkittävästi tuotannon joustoa, kuten **varastoja ja huipputuotantokapasiteettia** (esimerkiksi kaasuvoimaloita). Tuotannon joustolla on tärkeä rooli uusiutuvan energian lisäämisessä ja toimitusvarmuuden turvaamisessa. Akkuvarastot tarjoavat lyhyen aikavälin joustoa, kun taas power-to-gas-to-power[7] (P2G2P) tarjoaa pitkän aikavälin joustoa (viikosta useaan viikkoon). Varastojen tärkeys kasvaa vuoteen 2030 asti, kun olemassa olevia lämpövoimaloita ajetaan alas, ja jälleen vuoden 2040 jälkeen, kun ydinvoimakapasiteetti vähenee. Vuonna 2050 tarvitaan kaikkiaan noin 4 GW akkuvarastoja, 6 GW P2G2P-kapasiteettia ja 3 GW (puhdasta) kaasuvoimaa osana sähköntuotantoa. Kotimaisen tuotannon jouston lisäksi tarvitaan rajasiirtoyhteyksiä. Mahdollisia esteitä tuotannon jouston rakentamiselle ovat puutteellinen taloudellinen kannustin investoida teknologiaan, jota käytetään vuodessa hyvin lyhyitä aikoja (kaasuvoima), ja rajalliset varastointimahdollisuudet tarvittavalle vedylle (P2G2P). Yhdistyminen osaksi eurooppalaista kaasu- ja vetyverkkoa voisi osittain helpottaa tilannetta.

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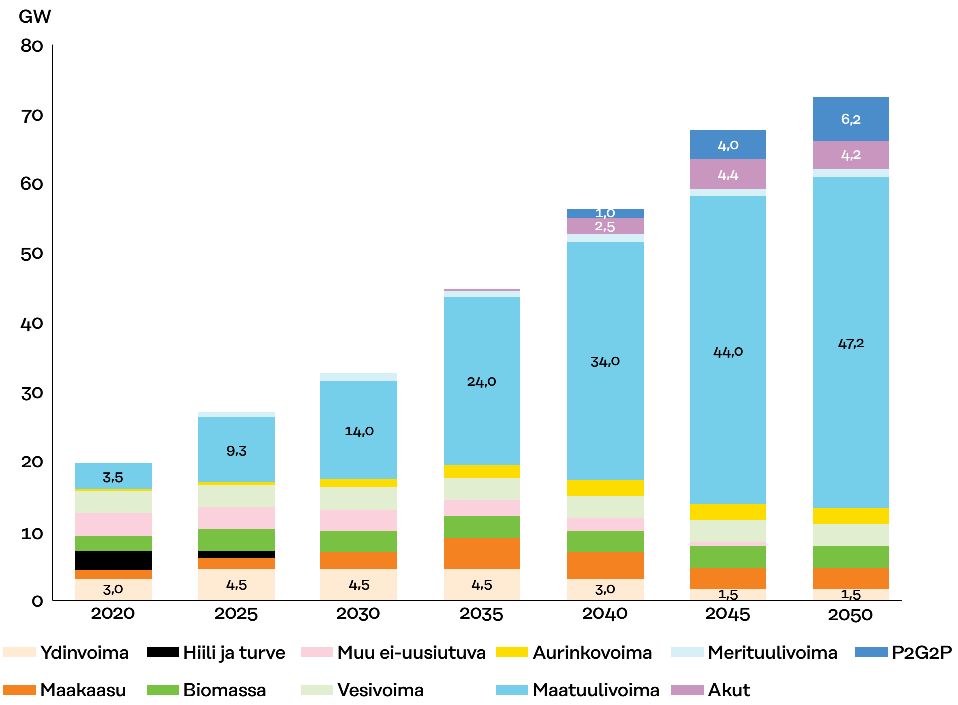
5 Hanhikiven ydinvoimalan toteutumiseen liittyvien epävarmuuksien takia sitä ei ole mallin oletuksissa asetettu varmistuneeksi tuotantokapasiteetiksi (toisin kuin Olkiluoto 3, jonka oletetaan valmistuvan 2022).
6 Lisääntynyt PtX -skenaariossa ydinvoiman kapasiteettia lisätään vuonna 2040.
7 Power-to-gas-to-power kuvastaa vedyn tai synteettisen kaasun tuottamista hiilineutraalilla sähköllä varastoon ja tämän varastoidun polttoaineen käyttöä myöhemmässä tilanteessa, kun muu sähköntuotanto, kuten tuulivoima, on vähäisempää.

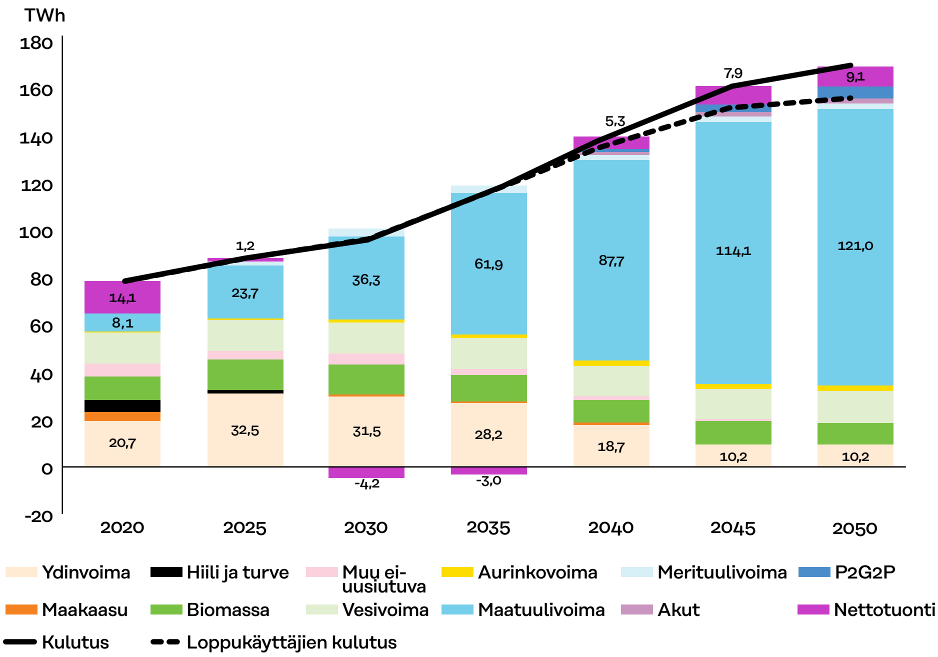
Kuva 4: Sähköntuotantokapasiteetti suoran sähköistämisen skenaariossa



Huomio: "Muu ei-uusiutuva" viittaa pieniin lämpövoimalaitoksiin, kuten ENTSO-E on määrittänyt julkaisuissa Mid-term Adequacy Forecast (MAF) ja Ten-Year Network Development Plan (TYNDP). Tyypillisesti lämpökapasiteetiltaan alle 20 MW:n yksiköt eivät kuulu EU:n päästökauppaan ja siksi ne on laskettu erikseen.
Lähde: Compass Lexeconin sähkömarkkinamallin tulokset

Sähköntuotannossa tuulivoiman osuus kasvaa selkeästi suurimmaksi jo vuonna 2035, yltäen jopa 73 prosenttiin vuonna 2050 (Kuva 5). Biomassaan perustuva sähkön ja lämmön yhteistuotanto (combined heat and power, CHP) pysyy pitkällä aikavälillä vakaana (tuottaen sähköä noin 10 TWh/v.). Tuotanto kuitenkin kasvaa keskipitkällä aikavälillä (korkeimmillaan 14 TWh/v. vuonna 2025), kun biomassaa käytetään korvaamaan hiiltä ja turvetta sähköntuotannossa. Vesivoima pysyy vakaana vuoteen 2050 asti tuottaen noin 14 TWh/v. Ydinvoima saavuttaa tuotantohuippunsa vuonna 2025 kattaen lähes kolmanneksen sähköntuotannosta. Tämän jälkeen ydinvoiman osuus laskee vuoteen 2050 asti, jolloin se kattaa enää 6 prosenttia.

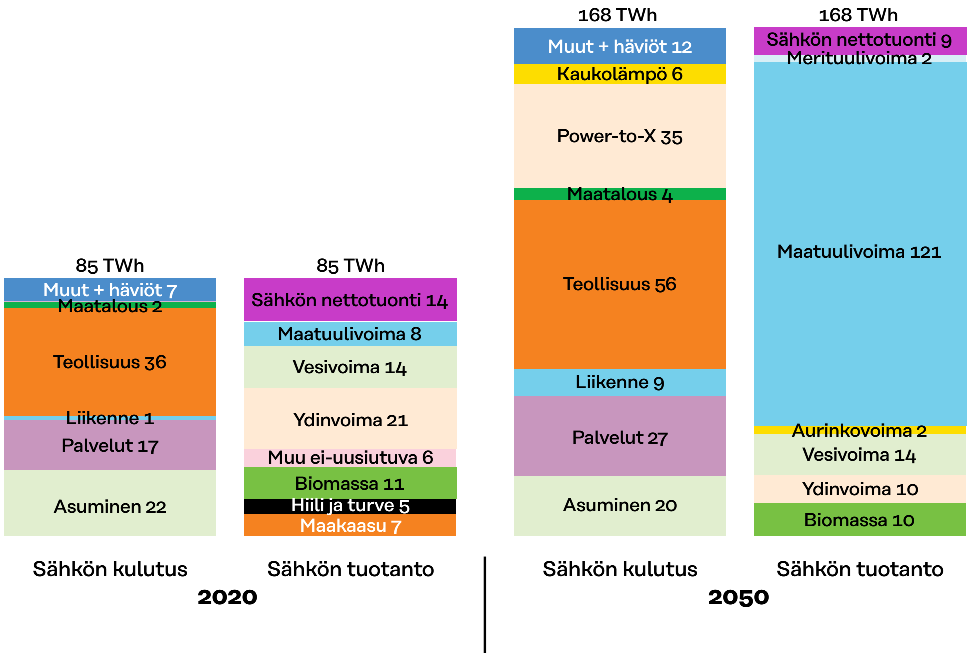
Kuva 5: Sähköntuotanto ja -kulutus suoran sähköistämisen skenaariossa



Huomio: 'Muu ei-uusiutuva' viittaa pieniin lämpövoimalaitoksiin (kuten ENTSO-E on määrittänyt MAF ja TYNDP -julkaisuissa); 'kulutus' viittaa sähköjärjestelmän kokonaiskulutukseen, ml. 'loppukäyttäjien kulutus' ja varastointihäviöt, joita aiheutuu pääasiassa P2G2P-kapasiteetista.
Lähde: Compass Lexeconin sähkömarkkinamallin tulokset

Suoran sähköistymisen skenaariossa tapahtuu kaksi merkittävää rakennemuutosta vuoteen 2050 mennessä. Ensinnäkin Suomesta tulee **tilapäisesti sähkön nettoviejä**. Verrattuna nykyiseen tilanteeseen, jossa noin viidennes Suomen vuosikulutuksesta on tuontia, vuosina 2030–2035 Suomi veisi nettona noin 3–4 TWh ylituotantoa vuodessa. Pääasialliset syyt tähän ovat ydinvoimakapasiteetin kasvu lyhyellä aikavälillä (Olkiluoto 3) ja maatuulivoimakapasiteetin nopea kasvu. Sähkönkulutuksen kasvu ja suurten ydinvoimaloiden alasajo tekevät Suomesta kuitenkin jälleen sähkön nettotuojan vuodesta 2040 eteenpäin. Koko tarkastelujakson ajan Suomen sähkövoimajärjestelmän saatavissa on lisää joustavuutta pohjoismaisesta vesivoimasta (Norja ja Ruotsi) ja ydinvoimasta (Ruotsi). Tämä rajasiirtoyhteyksien tuoma joustavuus on tärkeässä asemassa tuulituotannon liittämiseksi osaksi sähkövoimajärjestelmää. Toista rakenteellista muutosta edustaa kasvava **ero sähkövoimajärjestelmän kokonaiskulutuksen ja loppukäyttäjien kulutuksen välillä,** mikä erottuu vuodesta 2040 eteenpäin (Kuva 5). Sähkövoimajärjestelmän kokonaiskulutus kasvaa selvästi loppukäyttäjän kulutusta suuremmaksi pääasiassa pitkäaikaisvarastoinnin (P2G2P) häviöiden takia (ero vuonna 2050 noin 14 TWh). Yhteenveto sähkövoimajärjestelmän muutoksesta on esitetty kuvassa 6.

Kuva 6: Sektorikohtainen sähköntuotanto ja -kulutus vuonna 2020 ja 2050 (TWh) suoran sähköistämisen skenaariossa



Lähde: Enerdatan POLES-mallin ja Compass Lexeconin sähkömarkkinamallin tulokset

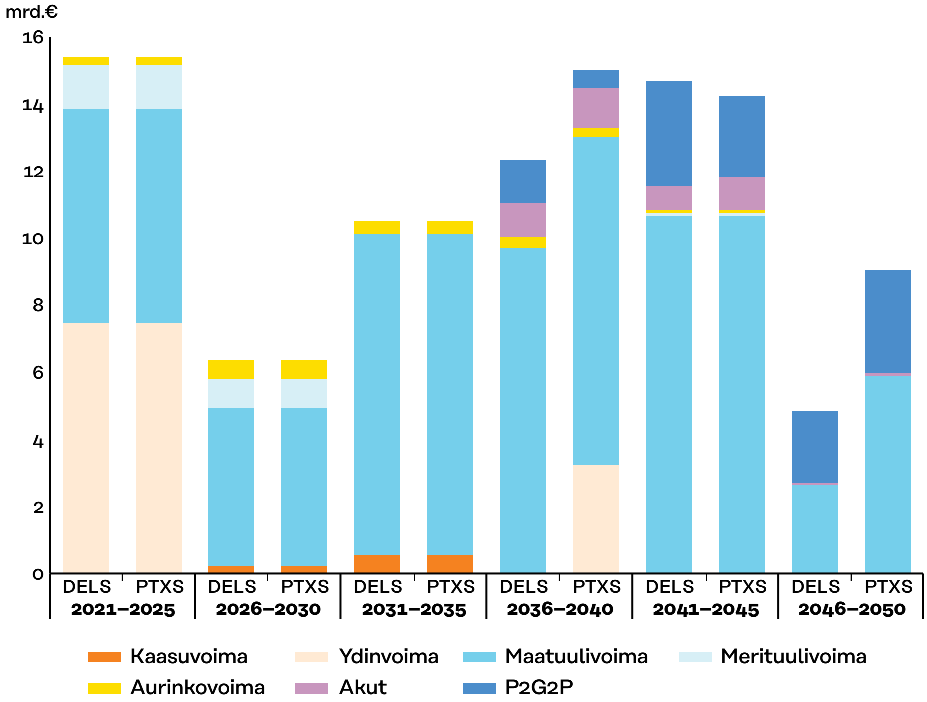
Sähköverkkojen näkökulmasta, sähköistyminen näkyy lähinnä **kantaverkossa**, jossa tarvitaan uutta siirtokapasiteettia yhdistämään uusi tuulivoimakapasiteetti uuteen kulutukseen. Kantaverkon uuden kapasiteetin lisäksi skenaarioissa oletetaan merkittävää kasvua rajasiirtokapasiteettiin (+1,5 GW vuoteen 2035 mennessä ja +5,8 GW vuoteen 2050 mennessä). Sähköistymisen odotetaan vaikuttavan hyvin rajallisesti **jakeluverkkoihin**, vaatien vain vähäisiä laajennuksia kapasiteettiin.

Investoinnit sähkövoimajärjestelmään

Tässä selvityksessä on analysoitu kustannukset kummankin skenaarion edellyttämistä investoinneista sähkövoimajärjestelmään. **Tuotannon ja varastoinnin** kustannusoletukset pohjaavat Euroopan komission tutkimuksiin (EC, 2018; Capros, et al., 2019), joissa teknologioiden kustannusten odotetaan laskevan tulevaisuudessa. Arvio vaadittavista investoinneista vuoteen 2050 asti on 64 miljardia €[8] suoran sähköistämisen skenaariossa ja 70 miljardia € lisääntynyt PtX -skenaariossa. Kummassakin skenaariossa suurin osa investoinneista (noin 70 %) kohdistuu maatuulivoimaan (Kuva 7).

8 Selvityksessä investointiluvut on esitetty reaaliarvoina nykyrahassa (perusvuosi 2020).

Kuva 7: Pääomakulut teknologioittain suoran sähköistämisen skenaariossa ja lisääntynyt PtX -skenaariossa



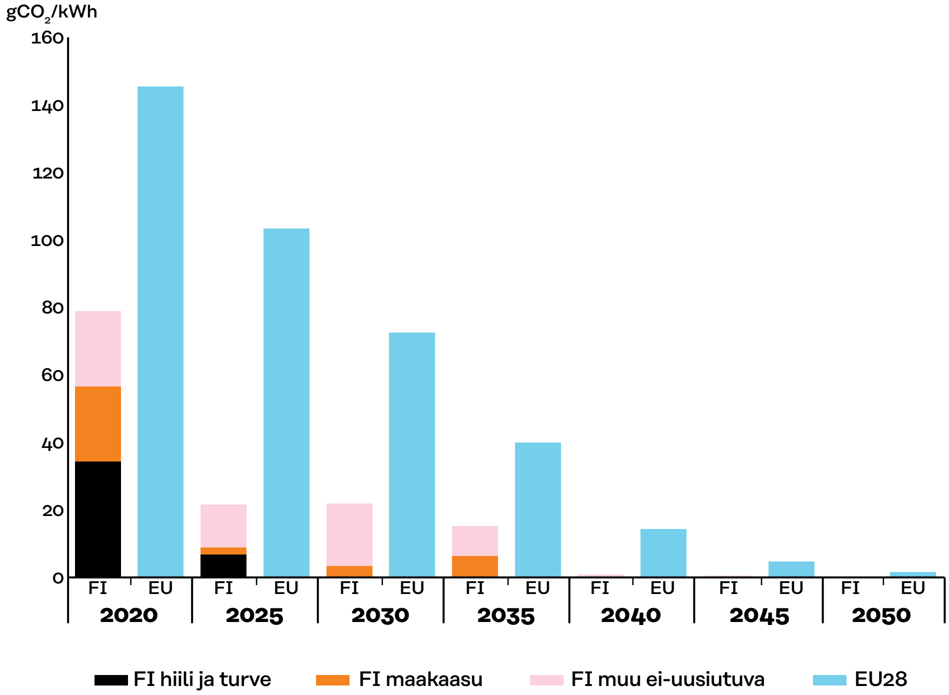
Huom.: Suoran sähköistämisen skenaario (DELS) ja lisääntynyt PtX -skenaario (PTXS). Ydinvoiman investointikustannukset vuosina 2021–2025 kuvastavat Olkiluoto 3:a, jonka oletetaan aloittavan sähköntuotanto vuonna 2022. Yksiköt miljardia euroa, arvoja ei ole diskontattu. Lähde: Compass Lexeconin sähkömarkkinamallin tulokset.

Arvio Suomen **kantaverkon** investointitarpeesta perustuu Fingridin (2021) tutkimukseen. Uuden kulutuksen ja tuotannon arvioidaan vaativan 1,5–3,0 miljardia € lisäinvestointeja 2020–2050 (Fingridin vuosille 2020–2030 varaaman 2 miljardin €:n lisäksi). Skenaarioissa kuvattujen **rajasiirtoyhteyksien** odotetaan vaativan investointeja noin 0,9 miljardia € 2020–2035 ja 2,6 miljardia € 2035–2050. Sähköistäminen ei aiheuta merkittäviä lisäkustannuksia **jakeluverkkoihin**, sillä tarvittavat vähäiset kapasiteetin laajennukset voidaan tehdä säännöllisten verkon päivitysten yhteydessä, kunhan tulevat muutokset kuormituksessa huomioidaan riittävän ajoissa.

Sähköntuotannon päästöt

Kummassakin skenaariossa sähköntuotanto on lähes päästötöntä jo vuonna 2040, ja päästökehitys on täten selvästi EU:n keskiarvoa edellä (Kuva 8). Vuosina 2025–2030 sähköntuotannon ominaispäästö ei laske, mutta sähkön tuotanto kasvaa lähes kolmanneksella.

Kuva 8: Suomen ja Euroopan sähköntuotannon hiilidioksidipäästöt (gCO_2/kWh) suoran sähköistämisen skenaariossa

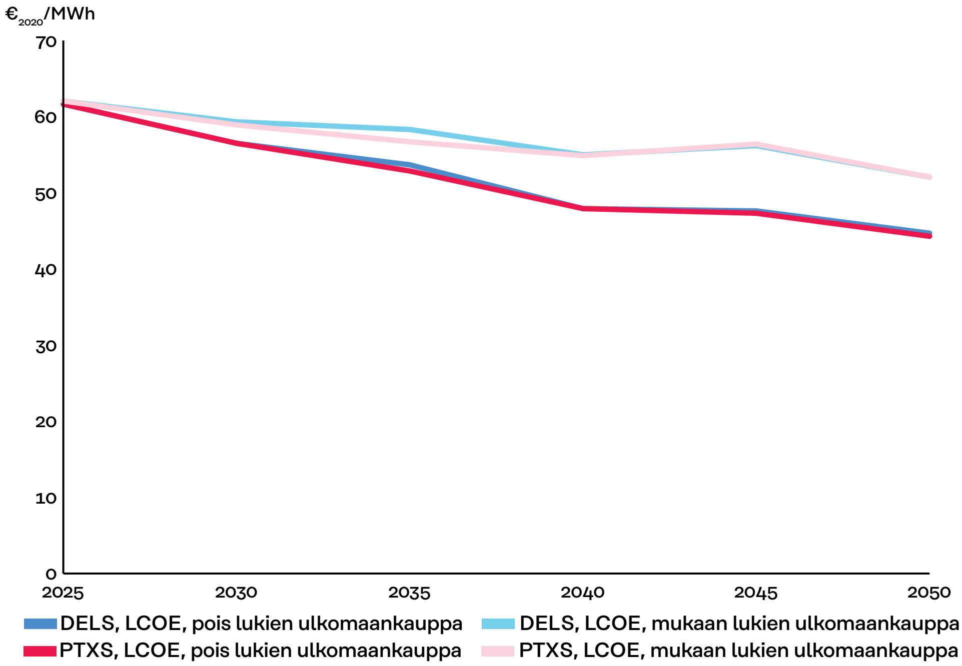


Lähde: Compass Lexeconin sähkömarkkinamallin tulokset

Sähkövoimajärjestelmän kustannus ja sähkön hinta

Vuoteen 2050 mennessä kummankin skenaarion sähköntuotannon kustannukset (LCOE) laskevat Suomessa nykytilanteeseen verrattuna noin 30 prosenttia. Sähköntuonti huomioiden kustannukset laskevat noin 20 prosenttia (Kuva 9).

Kuva 9: Sähkövoimajärjestelmän kokonaiskustannus energiayksikköä kohti

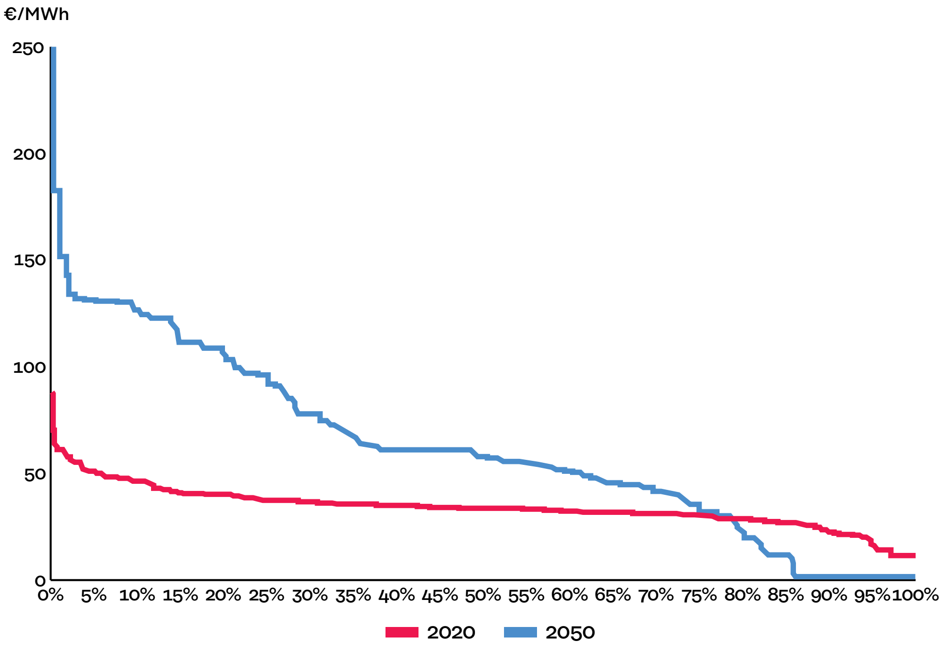


Huom.: Suoran sähköistämisen skenaario (DELS) ja lisääntynyt PtX -skenaario (PTXS). Yksikkönä LCOE (€/MWh). LCOE tarkoittaa tasoitettua sähkön hintaa eli pääoma-, käyttö- ja huoltokustannukset on jaettu tuotannolla; veroja ja hiilen hintaa (päästökauppa) ei ole huomioitu. Ulkomaankauppa kuvastaa sähkön tuonnin ja viennin arvoa tai kustannusta.
Lähde: Compass Lexeconin sähkömarkkinamallin tulokset.

Lisääntynyt vaihteleva sähköntuotanto muuttaa sähkön pörssihinnan[9] (spot-hinta) dynamiikkaa. Hintavaihtelu lisääntyy eli vuodessa on enemmän hetkiä, jolloin sähkön hinta on korkeampi kuin nykyään sekä hetkiä, jolloin hinta on lähellä nollaa (Kuva 10). Sähkön keskimääräinen[10] pörssihinta nousee 86 prosenttia nykytilanteesta vuoteen 2050 mennessä.

9 Pörssihinta (spot-hinta) kuvastaa sähkön hintaa sähkömarkkinoilla. Pörssihinta perustuu sähkön kysyntään ja tarjontaan jokaisella tunnilla sekä vaadittavan tuotannon (marginaalisen) kustannukseen. Tuotantoteknologioiden kustannukset (LCOE) ovat tyypillisesti alemmat kuin pörssihinta.
10 Keskiarvo vuoden tuntien ajalta. Ei huomioi oikeita asiakaskuormia ja kysyntäjoustoa, jolla vältetään sähkön ostaminen kalliimpina tunteina.

Kuva 10: Sähkön pörssihinnan pysyvyyskäyrä suoran sähköistämisen skenaariossa



Huom.: Pysyvyyskäyrä kuvastaa minkä osuuden vuoden tunneista (8760 tuntia vuodessa) sähkön hinta on kuvaajan käyrän osoittama tai korkeampi.
Lähde: Compass Lexeconin sähkömarkkinamallin tulokset

Loppukuluttajan energialaskun näkökulmasta kasvavaa sähkönkulutusta ja siihen liittyvää kasvavaa kustannusta tasapainottavat energiatehokkuuden parantumisen myötä laskeva kokonaisenergiankulutus ja sähköistämisen myötä vähenevä fossiilisten polttoaineiden kulutus.

Herkkyysanalyysit tuulivoiman rakentamisen ja kysynnän jouston saatavuuden rajoittamiseen

Tutkimuksessa tehtiin kaksi herkkyysanalyysiä. Ensimmäinen rajoittaa **maatuulivoiman potentiaalin** 25 GW:iin (alkuperäinen potentiaali 54 GW). Suoran sähköistämisen skenaariossa maatuulivoiman rajoittaminen lisää selvästi ydinvoiman käyttöä sähköntuotannossa (+4,5 GW vuonna 2050) sekä tarvittavaa akkukapasiteettia. Toisaalta kasvava ydinvoimakapasiteetti vähentää tarvetta pitkän aikavälin P2G2P-varastoille. Sähköntuonti lisääntyy, mikä näkyy hieman pienentyvänä sähköntuotannon kustannuksena Suomessa, mutta johtaa kokonaiskustannuksien kasvuun.

Toinen herkkyysanalyysi puolittaa **kysyntäjouston** potentiaalin alkuperäisestä. Vähentynyt kysyntäjousto kasvattaa tarvittavaa tuotannon joustavuutta (varastoja) ja edellyttää lisää tuotantoa kattamaan lisääntyneet varastointihäviöt. Tämä puolestaan johtaa kasvaneisiin sähkövoimajärjestelmän kustannuksiin. Kaasuvarastojen määrän ja niille sopivien rakennuskohteiden ollessa rajallisia kysyntäjouston tärkeys korostuu. Jotta kysyntäjouston täysi potentiaali saataisiin käyttöön, saatetaan tarvita lisää kannustimia, informaatio-ohjausta sekä laajaa digitaalisten ratkaisujen käyttöönottoa.

Johtopäätökset ja seuraavat askeleet

Kunnianhimoiset ilmasto- ja energiatavoitteet (hiilineutraalius 2035 ja päästöttömyys 2050) ovat toteuttamiskelpoisia. Tavoitteet ovat saavutettavissa turvautumatta vielä tuntemattomiin teknologioihin tai ylioptimistisiin parannuksiin energiatehokkuudessa ja ilman pysyvää biomassan käytön kasvua, joka vaarantaisi Suomen metsien hiilinielun. Suurimmasta osasta kasvihuonekaasupäästöjä voitaisiin päästä eroon suoralla ja epäsuoralla sähköistämisellä. Jäljelle jäävät päästöt maataloudesta, teollisuuden prosesseista ja kotitalousjätteistä voitaisiin kompensoida käyttämällä bioperäisen hiilen talteenottoa ja varastointia (BECCS).

Selvityksessä tarkasteltiin erityisesti epäsuoran sähköistämisen eli elektrolyysiin pohjautuvan vedyn ja synteettisten polttoaineiden (power-to-X, PtX) käyttöä. PtX-polttoaineet voivat olla kilpailukykyisiä raskaassa liikenteessä, ja teollisuudessa ne voivat mahdollistaa päästöjen vähentämisen sellaisissa sovelluskohteissa, joissa suora sähköistäminen on vaikeaa tai mahdotonta. Teollisuuden muun kuin energiakäytön, erityisesti kemianteollisuuden raaka-aineiden, päästöjä on mahdollista vähentää biomassalla, kuten teollisuuden jäteliemillä, PtX-ratkaisuilla ja lisääntyneellä kierrätyksellä.

Selvityksessä mallinnetuissa skenaarioissa merkittävin kustannustehokas sähköntuotantomuoto on maatuulivoima, jota tukevat vahvasti tuotannon ja kysynnän jousto. Selvitys osoittaa myös, että jos maatuulivoiman ja kysyntäjouston täyttä potentiaalia ei saavuteta, aiheutuu siitä tuntuvia lisäkustannuksia Suomen sähkövoimajärjestelmälle. Kasvava vaihtelevan tuotannon määrä ja vanhojen fossiilisten voimalaitosten alasajo lisäävät merkittävästi tarvetta tuotannon joustolle Suomessa. Etenkin vuoden 2040 jälkeen viikoittaista ja pidemmän aikavälin joustavuutta skenaarioissa tarjoaa power-to-gas-to-power-kapasiteetti (P2G2P), ja akkujärjestelmät puolestaan päivänsisäistä joustavuutta.

Sähköistäminen näkyy selvästi kantaverkossa, jossa vaaditaan lisää siirtokapasiteettia. Vastaavaa lisäkapasiteettia ei vaadita jakeluverkoilta, mutta kysyntäjouston tärkeys korostuu kysyntähuippujen rajaamisessa.

Kummassakin skenaariossa Suomen sähköntuotannon kustannukset (LCOE) laskevat nykytilanteesta lähes 30 prosenttia vuoteen 2050 mennessä. Selvitys osoittaa, että energiatehokkuusparannukset ja vähentynyt fossiilisten polttoaineiden käyttö tasoittavat kasvavaan sähkönkulutukseen liittyviä kustannuksia.

Mallinnuksen, laadullisten analyysien sekä sidosryhmätyöpajojen avulla on tunnistettu useita tärkeitä **seuraavia askeleita**, jotta kustannustehokas päästöjen vähentäminen olisi mahdollista. Tulisi selvittää, miten voidaan asettaa teollisuudelle tarvittavat kansalliset tai EU-tason kannustimet, jotta vaaditut investoinnit hiilineutraaliin prosessiteknologiaan ja raaka-aineisiin voidaan toteuttaa. Vaihtoehtoja luoda kannustimet negatiivisille päästöille (esimerkiksi BECCS) tulisi tutkia ja perustaa markkina negatiivisille päästöille kansallisella tai EU-tasolla. Päästöjä vähentäville teollisuuden toimijoille olisi varmistettava suotuisa ja kilpailukykyinen sijoitusympäristö, sisältäen nopeat luvitusprosessit ja ennakoitavan sääntelyn. Tulisi kehittää EU-tason säätelyä, joka tukisi vetyteollisuuden ja sen tarvitseman infrastruktuurin rakentamista Suomeen. Lisäksi Suomen tulisi kehittää selkeä kansallinen vetystrategia (esimerkiksi osana kansallista ilmasto- ja energiastrategiaa).

Tuulivoimalla on merkittävä asema tulevaisuuden sähköntuotannossa, ja täten olisi tutkittava ratkaisuja, joilla voidaan rakenteellisesti vähentää puolustusvoimien asettamia rajoitteita tuulivoiman rakentamiseen. Esimerkkejä näistä ratkaisuista ovat puolustusvoimien etukäteen asettamat selkeät rakennusrajat tuulivoimalle, avoimempi keskustelu rakennussuunnitelmista sekä tutkahäiriöiden vähentämiseen tähtäävä tutkimus- ja kehitystyö. Tulisi myös tutkia erilaisia keinoja, joilla tuulivoimaloiden pitkiä kaavoitus- ja luvitusprosesseja voitaisiin lyhentää (esimerkiksi lisäämällä resursseja valitusten käsittelyyn). Tulevaisuuden tuotannon ja kulutuksen jouston varmistamiseksi tulisi säännöllisesti seurata kannustimien riittävyyttä ja selvittää vaihtoehtoja mahdollisiin tarvittaviin kannustimiin.

Tätäkin selvitystä, kuten mitä tahansa tulevaisuuteen tähtäävää selvitystä tai mallinnusta, koskevat **rajoitteet ja epävarmuustekijät**, jotka yleisesti liittyvät tehtyihin oletuksiin. Esimerkiksi jos teknologian kehittymisestä ja sähköistymisestä johtuvat oletetut energiantehokkuuden parantumiset eivät toteudu, johtaisi se korkeampaan energian loppukäyttöön, hitaampaan päästöjen vähentämiseen ja erilaiseen energiataseeseen. Vastaavasti jos tulevaisuuden teknologiakustannukset (esimerkiksi merituulivoiman tai ydinvoiman) poikkeavat merkittävästi oletetuista, saattaisi se johtaa erilaiseen kustannustehokkaan energiantuotannon rakenteeseen ja polkuun päästöjen vähentämiseen. Poikkeamat biomassan saatavuudessa tai kustannuksessa energiakäyttöä varten voivat myös aiheuttaa merkittäviä eroavaisuuksia. Näitä epävarmuuksia tulisi seurata ja tulisi selvittää, mikä olisi vaikutus, jos tuoreimmista kehitysoletuksista poiketaan merkittävästi. **Tulevaisuudessa tutkimusta** tulisi keskittää strategisen infrastruktuurin tekniseen sääntelyyn ja politiikan suunnitteluun, jotta voidaan varmistaa kustannustehokas ja toimitusvarma energiantuotanto Suomessa.

Sammanfattning

Tidigare studier av Finlands energisystem – inklusive de som gjorts på uppdrag av Sitra – har understrukit vikten av att elektrifiera energianvändningen för att uppnå en omfattande minskning av koldioxidutsläppen. Det råder dock fortfarande stor osäkerhet om strukturen för och vägen mot minskade koldioxidutsläpp i det finska energisystemet.

Syftet med studien

Denna studie ger en övergripande bild av elektrifieringen och minskningen av koldioxidutsläpp i Finland och identifierar möjliggörande faktorer, smärtpunkter och rekommendationer för de följande stegen. Klimatneutralitet bör nås senast år 2035, i linje med det nationella klimatmålet, och en fullständig utfasning av fossila bränslen [1]senast år 2050.

Vi beaktar det befintliga finska energisystemet, den krävda leveranssäkerheten och tillgängliga lokala resurser. Vi tar särskild hänsyn till nyare tekniska lösningar som efterfrågeflexibilitet samt väte och andra syntetiska bränslen.

Metodologi

Vi modellerar **två elektrifieringsscenarier** för utvecklingen av det finska energisystemet. I scenariot för direkt elektrifiering antas en omfattande direkt elektrifiering av de flesta tillämpningarna, medan det utökade PtX-scenariot baseras på antaganden om en större användning av indirekt elektrifiering med elbaserat väte och andra syntetiska bränslen (”power-to-X”, PtX).

För att elektrifiering ska uppnås **bedöms först den framtida efterfrågan på energi i Finland.** Vi tar fram prognoser för efterfrågan på primärenergi i Finland utgående från uppskattningar av befolkningstillväxt samt BNP-tillväxt inom industri, tjänster och jordbruk. Utifrån dessa beaktas rimliga men betydande effektivitetsvinster på grund av tekniska framsteg och elektrifiering. Här skulle elektrifiering i regel förbättra den övergripande energieffektiviteten. Till exempel har elbilar högre verkningsgrad än bilar med förbränningsmotor.

Vi tillämpar en simuleringsmodell av den europeiska energimarknaden (POLES[2], från Enerdata) för att simulera **konkurrensen mellan tekniker och bränslen över tid under ständigt ökande press för att minska koldioxidutsläppen**. Enkelt uttryckt ökar den kolprissignal som modellen fäster vid fossila bränslen över tid. Simuleringsmodellen ersätter därefter successivt fossila bränslen med det mest konkurrenskraftiga icke-fossila alternativet.

För det andra fastställs det **mest kostnadseffektiva sättet att producera den elektricitet som behövs** under de givna årliga koldioxidmålen med hjälp av Compass Lexecons leverans-

1 Med fullständig utfasning av fossila bränslen avser vi att de återstående utsläppen av växthusgaser från jordbruk, industriprocesser och avfall neutraliseras med hjälp av negativa utsläpp, till exempel BECCS (bioenergy with carbon capture and storage, dvs. bioenergi med koldioxidinfångning och lagring). Nettosänkan för markanvändning, förändrad markanvändning och skogsbruk (LULUCF) antas ligga på en genomsnittlig nivå av 21,4 Mt/år under hela perioden.

2 POLES-modellen har ursprungligen tagits fram av IEPE (Institute for Economics and Energy Policy), numera GAEL (Grenoble Applied Economics Lab). Modellversionen som användes för denna rapport är den POLES-modellversion som ägs och drivs av Enerdata, POLES-Enerdata.

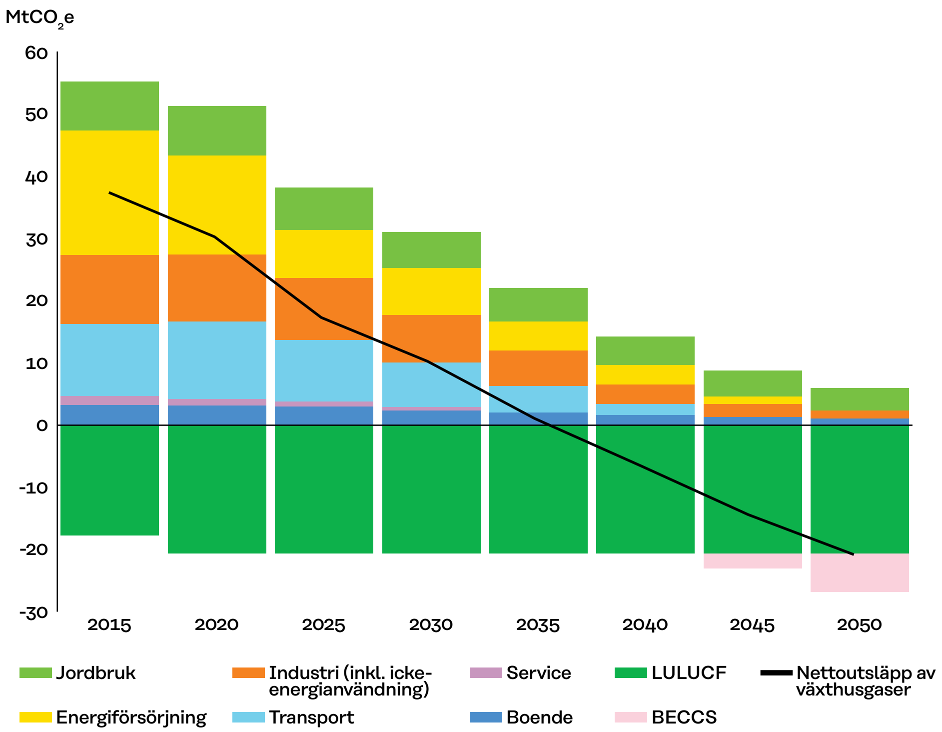
modell för energisektorn. Den kostnadsoptimerade kapacitetsutvidgningen härleds genom att **minimera de totala kraftsystemkostnaderna** under ett antal specifika begränsningar (t.ex. kapacitetspotential, utsläppsgränser, sammankopplingskapacitet). Antaganden och källor för dessa begränsningar samt övriga teknisk-ekonomiska parametrar diskuterades och anpassades medan studien utvecklades, samtidigt som även feedback från intressenter beaktades.[3]

I den **tredje steget** identifierades viktiga **möjliggörande faktorer och flaskhalsar** – även med hjälp av workshopstillfällen med intressenter, samt intervjuer – som en grund för att ta fram rekommendationer för de följande stegen.

Framtida efterfrågan på energi i Finland

Baserat på POLES-simulationen uppnås både det finska **växthusgasutsläppsmålet** avseende kolneutralitet fram tills år 2035 och en fullständig utfasning av fossila bränslen inom energisystemen senast år 2050 i båda scenarierna. Utvecklingen för nettoutsläpp av växthusgaser i scenariot för direkt elektrifiering fram till 2050 visas i Figur 1. Nettoutsläppen av växthusgaser minskar ständigt under åren 2020–2050 och når nästan 0 $MtCO_2e$ år 2035 och -21 $MtCO_2e$ år 2050, vilket är det antagna värdet för kolsänkan för markanvändning, förändrad markanvändning och skogsbruk (LULUCF). Jämfört med 1990 års nivåer minskar bruttoutsläppen av växthusgaser med 69 % till år 2035 respektive 100 % till år 2050.

Figur 1: Nettoutsläpp av växthusgaser och utsläpp per sektor, scenariot för direkt elektrifiering



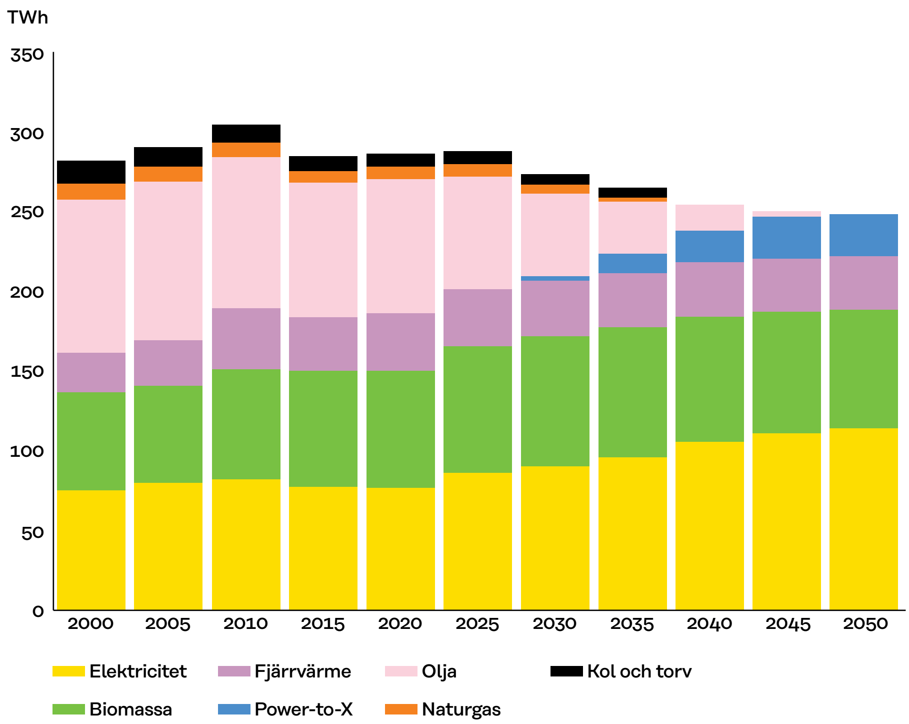
Källa: POLES-Enerdata-modellresultat av Enerdata

3 Till exempel antogs kapacitetsfaktorer, som mäter det övergripande utnyttjandet av en kraftgenererande anläggning, till 34 % för nya vindkraftverk på land och 47 % för nya vindkraftverk till havs.

Alla sektorer bidrar till denna minskning, då transport, tjänster och energiförsörjning når fullständig utfasning av fossila bränslen fram till år 2050, medan restutsläpp kvarstår i vissa sektorer som är svåra att minska, främst inom jordbruk (4 MtCO_2e), industriprocesser (1 MtCO_2e) och hushållsavfall (1 MtCO_2e). Dessa återstående utsläpp kompenseras genom att använda bioenergi med koldioxidinfångning och lagring (BECCS) vid energiförbrukning inom industrin för att nå fullständig utfasning av fossila bränslen (dvs. noll bruttoutsläpp av växthusgaser) i systemen år 2050.

Som figur 2 visar kommer den slutliga energiefterfrågan i Finland minska något fram till år 2050 i scenariot för direkt elektrifiering och uppgå till cirka 250 TWh från 290 TWh år 2015. Denna minskning drivs i huvudsak av elektrifiering av slutanvändning i form av uppvärmning och mobilitet, särskilt genom värmepumpar och elektriska fordon som har högre verkningsgrad än alternativen. Elförbrukningen ökar därför snabbt och blir den viktigaste energibäraren fram till år 2050 då den står för 46 % av den slutliga energianvändningen (från 27 % år 2015), följt av bioenergi (30 %), fjärrvärme (14 %) och power-to-X (11 %). Scenariot för direkt elektrifiering förlitar sig särskilt på den antagna tillgången till tillräckligt med hållbar och rimligt prissatt biomassa för energianvändning. I det utökade PtX-scenariot täcks delar av denna användning av biomassa i stället av PtX-bränslen. Sammantaget krävs en mer ingående analys för att bedöma hur mycket hållbar biomassa det sannolikt kommer att finnas för energianvändning.

Figur 2: Slutlig energiförbrukning per bränsle, scenario för direkt elektrifiering



Källa: POLES-Enerdata-modellresultat av Enerdata

För att koldioxidutsläppen ska vara noll i de slutliga sektorerna, kommer förbrukningen av fossila bränslen att helt fasas ut fram till år 2050 och till stor del ersättas med direkt elektrifiering av slutanvändningen, främst genom en omfattande utveckling av värmepumpar för uppvärmning och elektriska fordon inom transportsektorn. Bioenergi och power-to-X-bränslen behövs också för sektorer där koldioxidutsläppen är svåra att minska, inklusive tunga transporter, vissa industriprocesser och kemiska råvaror.

Inom industrisektorn kommer direkt elektrifiering att ersätta större delen av förbrukningen av fossila bränslen, och därför står elektricitet för hälften av efterfrågan inom industrin år 2050 (56 TWh elektricitet av 112 TWh i scenariot för direkt elektrifiering). Till exempel kan ljusbågsugnar som använder elektricitet användas i industriella tillämpningar med hög temperatur i stället för ugnar som används med fossila bränslen. Efter år 2030 möjliggör PtX-bränslen fullständig utfasning av fossila bränslen inom industriprocesser som är svåra att elektrifiera i båda scenarierna, i synnerhet i fråga om stålreduktion och vissa högtemperaturprocesser. I industriell användning av fossila bränslen för annat än energi, framför allt kemiska råvaror, minskas koldioxidutsläppen med hjälp av bioenergi, till exempel med råvaror baserade på massaindustrins spillvätskor och power-to-X-bränslen samt ökad återvinning. År 2050 kommer power-to-X-bränslen att stå för cirka 15 TWh (11 %) i scenariot för direkt elektrifiering och 30 TWh (22 %) i det utökade PtX-scenariot av all industriell användning, såväl för energi som för andra ändamål.

Inom transportsektorn lämnar långtgående elektrifiering av de lätta transportsegmenten – då över två tredjedelar av personbilarna är helt elektriska år 2050 i scenariot för direkt elektrifiering – begränsat utrymme för fordon med förbränningsmotorer som drivs med power-to-X-bränslen eller biobränslen. De två sistnämnda förblir dock konkurrenskraftiga i tunga transporter, med en återstående marknadsandel på över 60 % år 2050. Övergången till elektriska fordon och förbättrade verkningsgrader i fordonen minskar den slutliga energiförbrukningen inom transportsektorn från 49 TWh år 2015 till 34 TWh år 2050.

Inom byggnads- och servicesektorn uppnås en fullständig utfasning av fossila bränslen i energiförbrukningen genom direkt elektrifiering (särskilt genom användning av värmepumpar i byggnader, samt fjärrvärme). Fram till år 2050 kommer värmepumpar att stå för över 90 % av den elektricitet som används för uppvärmning inom byggnadssektorn och för mer än 55 % av fjärrvärmen.

Denna utveckling i efterfrågan kommer i båda scenarierna att medföra att fossila bränslen ersätts helt i primärenergimixen fram till år 2050. **Bioenergi** (dvs. olika slags biomassa i fast, flytande eller gasform) har överlag en **betydande roll för minskade koldioxidutsläpp**. Användningen av bioenergi kommer att öka på medellång sikt på grund av den snabbt ökande användningen av bioenergi för fjärrvärme, men kommer att **återgå till 2020 års nivå fram till år 2050** (Figur 3).[4]

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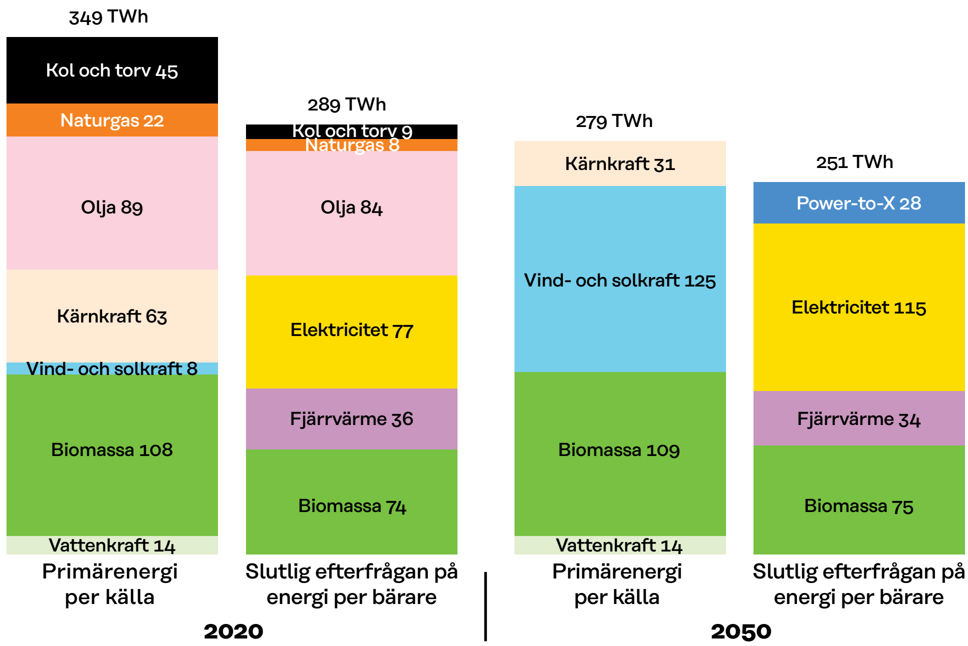
4 Det faller utanför omfattningen av denna analys att bedöma tillgängligheten av hållbar biomassa för energianvändning. Detta vore ett viktigt framtida analysområde.

Figur 3: Efterfrågan på primär och slutlig energi 2020 och 2050 (TWh), scenariot för direkt elektrifiering



Källa: POLES-Enerdata-modellresultat av Enerdata

Medan det utökade PtX-scenariot överlag är i linje med utvecklingarna enligt scenariot för direkt elektrifiering, resulterar det i mer PtX-användning i synnerhet inom industrin och tunga transporter. År 2050 kommer PtX-användningen att öka efterfrågan på elektricitet för väteproduktion genom elektrolys med 34 TWh i scenariot för direkt elektrifiering och 60 TWh i scenariot för utökad PtX.

Den framtida energiförsörjningen i Finland

Jämfört med nuläget kommer den totala **efterfrågan på el att öka med över 20 % till år 2035 och fördubblas fram till år 2050**, och samtidigt utgöra över hälften av efterfrågan på slutlig energi. Detta kräver betydande ändringar i det finska elsystemet. Baserat på detta behov utvecklar denna studie kostnadseffektiva utvecklingsbanor för elförsörjning i Finland för båda scenarierna.

I båda scenarierna domineras kraftproduktionen av vindkraft på land, stött av betydande flexibilitet på utbudssidan.

I de analyserade scenarierna kommer kraftsektorn i Finland att genomgå en betydande omvandling med avseende på dess storlek och struktur under de kommande 30 åren. För att svara mot den ökande efterfrågan till följd av utbredd elektrifiering kommer den finska **genereringskapaciteten** att mer än tredubblas fram till 2050 och öka från under 20 GW år 2020 till över 70 GW i scenariot för direkt elektrifiering (Figur 4). Över 80 % av kapacitetsökningarna är **vindkraft på land**, eftersom deras produktionskostnader förblir lägre än för konkurrerande produktionstekniker för utfasning av fossila bränslen (till exempel vindkraft till havs eller kärnkraft) under de anpassade antagandena och då tillräcklig potential finns tillgänglig. Begränsningar för utbyggnaden av vindkraft t.ex. på grund av Försvarsmaktens krav eller minskad allmän acceptans kan dock skapa hinder för denna väg till effektiv utfasning av fossila bränslen. Det förefaller vara nödvändigt att utforska alternativ för att tillgodose både Försvarsmaktens behov och utbyggnaden av vindkraft.

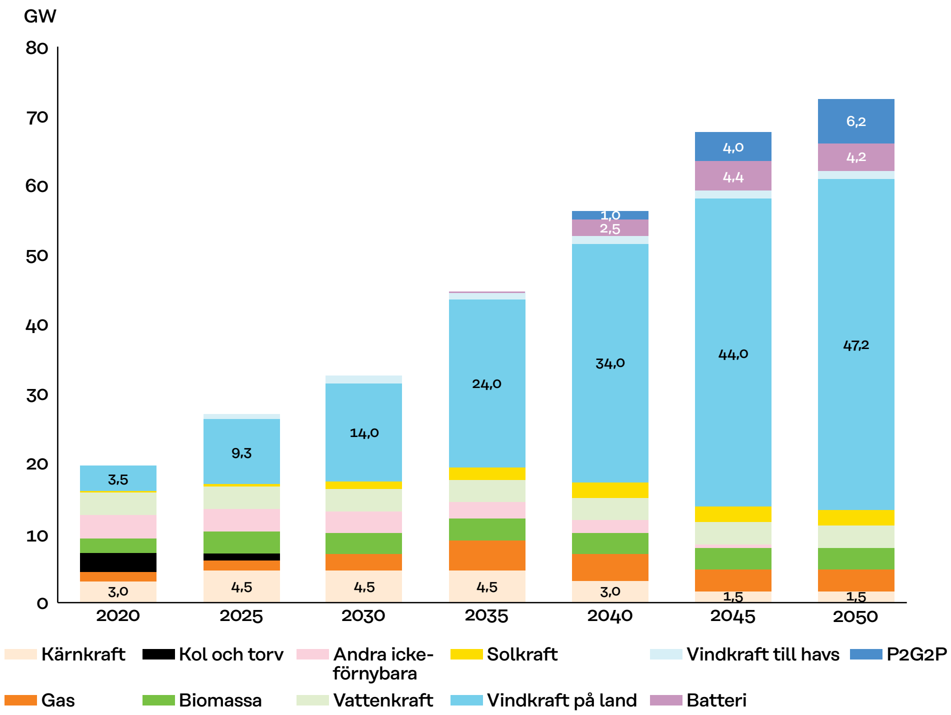
Under de definierade antagandena, inklusive utsikterna för efterfrågan på energi, kostnadsminskningar för de olika teknologierna och potentialen för förnybara energikällor (RES), kommer **kärnkraftskapaciteten** inte att byggas ut utöver Olkiluoto 3 i den kostnadsoptimerade kapacitetsmixen i scenariot för direkt elektrifiering.[5] Den förblir därför fortfarande den enda kärnkraftskapaciteten i det finska kraftsystemet efter 2040, när Olkiluoto 1 och 2 och Lovisa 1 och 2 tas ur bruk efter förlängda livscykler.[6] De förlängda livscyklerna för dessa anläggningar spelar en viktig roll i det skisserade scenariot för utfasning av fossila bränslen. Skulle de förväntas utebli kommer det att finnas ett brådskande behov av planeringsalternativ för att öka produktionen av koldioxidsnål elektricitet.

Den stora andelen vindkraftskapacitet kräver utbyggnad av betydande flexibilitet på utbudssidan – **lager och gasturbiner för produktionstoppar** – för att säkerställa integrationen av variabel förnybar produktion och leveranssäkerhet. Batterier medför flexibilitet på kort sikt medan kraft-till-gas-till-kraft (power-to-gas-to-power, P2G2P) erbjuder lagring på längre sikt, veckovis eller under flera veckor. Lagrens betydelse ökar efter nedläggningen av termisk kapacitet fram till år 2030, och igen efter år 2040 när den åldrande kärnkraftskapaciteten tas ur drift medan vindkraft på land fortsätter att öka. Totalt sett ingår cirka 4 GW batterier, 6 GW P2G2P och 3 GW topproduktionskapacitet för (ren) gas i kraftproduktionsmixen år 2050. Denna inhemska flexibilitet på utbudssidan kompletteras med ytterligare gränsöverskridande sammankopplingar. Möjliga flaskhalsar för att bygga upp flexibilitet på utbudssidan kan vara otillräckliga ekonomiska incitament för att investera i teknik med mycket liten faktisk produktion (gasturbiner) och den begränsade tillgången till lagringskapacitet för väte som krävs för P2G2P-kapaciteter – ensammankoppling med en europeisk (ren) gasinfrastruktur kan underlätta saken.

5 Med tanke på den nuvarande osäkerheten när det gäller byggandet och tidpunkten för Hanhikivi kärnkraftverk, tillfördes det inte som definitiv tillgänglig kapacitet till studiens antaganden (till skillnad från Olkiluoto 3 som antogs stå klart år 2022).

6 I scenariot för utökad PtX Scenario tillförs ytterligare kärnkraftskapacitet år 2040.

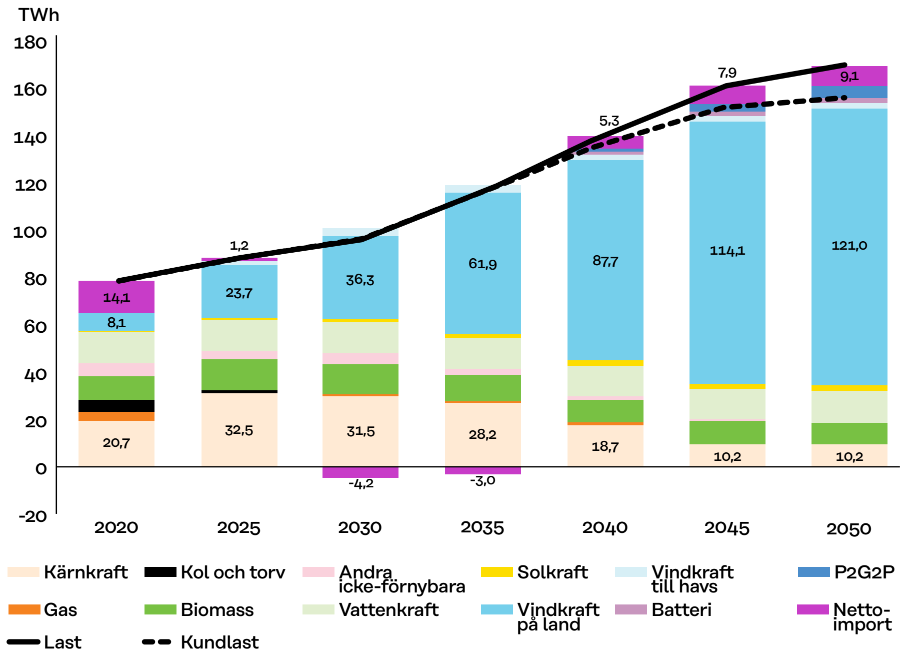
Figur 4: Installerad kraftkapacitet, scenariot för direkt elektrifiering



Obs: "Andra icke-förnybara" avser små distribuerade värmeenheter (small distributed thermal units) enligt definitionen av ENTSOE i tillräcklighetsprognosen på medellång sikt (Mid-term Adequacy Forecast, MAF) och tioårsplanen för nätverksutveckling (Ten-Year Network Development Plan, TYNDP). Enheter med en värmekapacitet under 20 MW faller i allmänhet inte under EU:s system för handel med utsläppsrätter (ETS) och redovisas därför annorlunda.
Källa: resultat från CL-kraftförsörjningsmodellen av Compass Lexecon

Figur 5 visar utvecklingen i kraftproduktion och efterfrågan i Finland i scenariot för direkt elektrifiering. Vindkraft på land börjar dominera kraftproduktionen från och med 2035 och når en andel på 73 % år 2050. **Biomassaproduktion** från kraftvärmeanläggningar förblir stabil på lång sikt (cirka 10 TWh/år) men ökar på medellång sikt (upp till högst 14 TWh år 2025) för att ersätta kol- och torveldad produktion. Vattenkraft förblir stabil under hela perioden och producerar uppskattningsvis 14 TWh per år. Kärnkraftsproduktion når sin topp år 2025, då den täcker mer än en tredjedel av den årliga kraftlasten i Finland, men minskar till cirka 6 % år 2050.

Figur 5: Kraftproduktion och efterfrågan (TWh), scenario för direkt elektrifiering

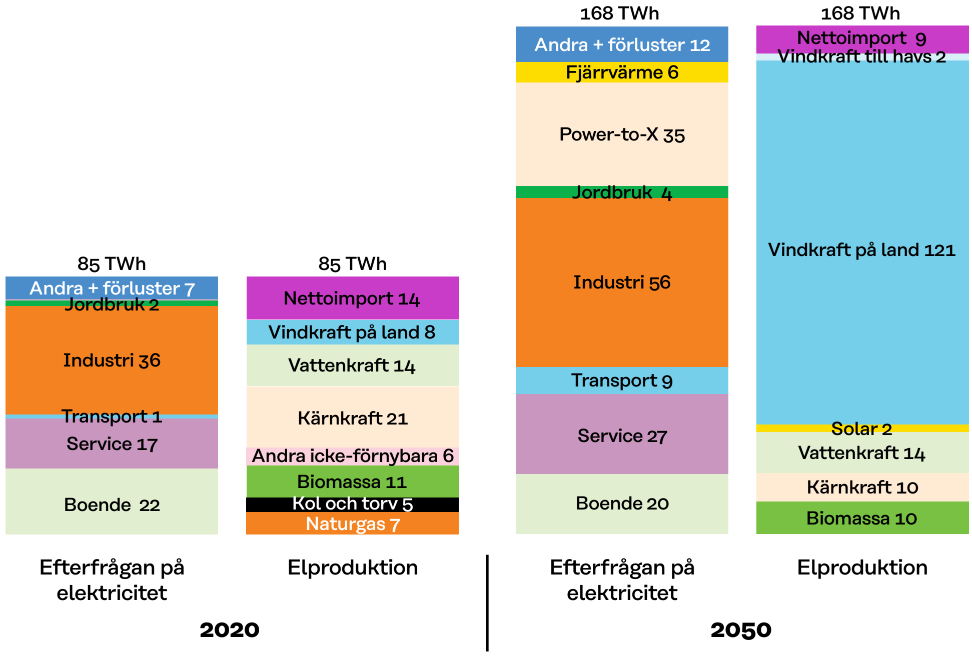


Obs: "Andra icke-förnybara" avser små distribuerade värmeenheter enligt definitionen av ENTSOE i MAF och TYNDP, "last" avser den totala systemlasten inklusive "kundlast" och lagringsförluster – främst från P2G2P-installationer.
Källa: resultat från CL-kraftförsörjningsmodellen av Compass Lexecon

Två viktiga strukturella förändringar kommer att ske i scenariot för direkt elektrifiering fram till år 2050. För det första kommer Finland att bli en **tillfällig nettoexportör av elektricitet**. Jämfört med den nuvarande nettoimporten på cirka en femtedel av den finska årsförbrukningen, exporterar Finland mellan 2030 och 2035 3–4 TWh överskottsproduktion årligen. De främsta orsakerna är ökad kärnkraftskapacitet på kort sikt (Olkiluoto 3) och den snabba tillväxten av vindkraftsproduktion på land. Från 2040 och framåt kommer Finland dock att åter bli nettoimportör på grund av en ökad kraftefterfrågan och avveckling av stor kärnkraftskapacitet. Under hela denna tid kommer flexibiliteten från nordisk vattenkraft (Norge och Sverige) och kärnkraftsproduktionen (Sverige) som är tillgänglig för det finska systemet via sammankopplingskapacitet spela att en viktig roll för att integrera finsk vindkraftsproduktion. Det andra strukturella förändringen representeras av den ökande **skillnaden mellan systemlast och kundlast** som visas i Figur 5 och blir tydlig från och med år 2040. Systemlasten blir successivt större än kundlasten. Skillnaden ökar till närmare 14 TWh år 2050 och beror huvudsakligen på effektivitetsförluster från P2G2P -omvandlingsprocessen som används för längre energilagring.

Den övergripande övergången inom kraftsektorn summeras i Figur 6.

Figur 6: Efterfrågan på elektricitet per sektor och elproduktion 2020 och 2050 (TWh), scenariot för direkt elektrifiering



Källa: POLES-Enerdata-modellresultat av Enerdata och resultat från CL-kraftförsörjnings-modellen av Compass Lexecon

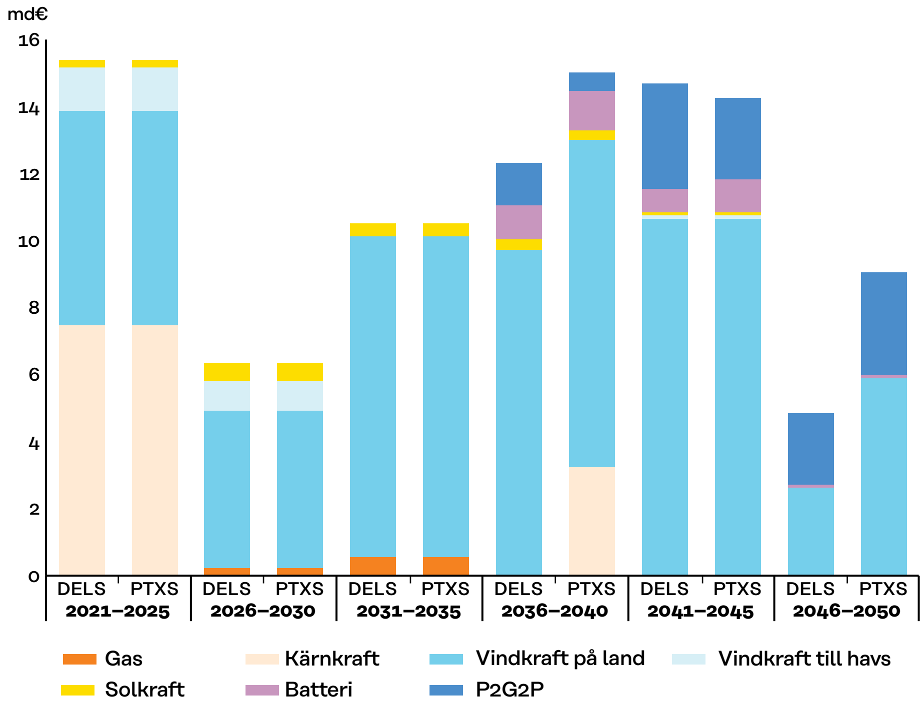
Ur ett nätverksperspektiv kommer stark elektrifiering huvudsakligen att påverka **överföringsnätet**, vilket ökar behovet av att utöka överföringskapaciteten, särskilt för att ansluta vindkraftsproduktionsplatser till efterfrågecentra. Dessutom förutsätter scenarierna en betydande utbyggnad av sammankopplingskapacitet (+1,5 GW år 2035 och +5,8 GW år 2050). Effekten av en stark elektrifieringsutveckling på **distributionsnätet** förväntas leda till endast begränsade behov av kapacitetsutökningar.

Betydande investeringar kommer att krävas för att utöka elektricitetssystemet i linje med kraven i de starka elektrifieringsscenarierna som analyserats

De investeringar som krävs för omvandlingen av det finska elsystemet uppskattades utifrån båda scenarierna. För utbyggnaden av den finska **produktions- och lagringskapaciteten** värderades därför de härledda optimala kapacitetsutökningarna med specifika investeringsantaganden i linje med Europeiska kommissionens Technology Pathways-studie (EC, 2018; Capros m.fl., 2019) – och därmed medräknades också kostnadsminskningar fram till 2050. Resultaten är uppskattningar av investeringar[7] fram till 2050 på cirka 64 miljarder $€_{2020}$ i scenariot för direkt elektrifiering och cirka 70 miljarder $€_{2020}$ i det scenariot för utökad PtX (odiskonterade summor). Den överlägset största andelen av investeringarna i båda scenarierna (närmare 70 %) riktas därmed mot vindkraftsutbyggnad på land (Figur 7).

7 I denna studie uttrycks alla monetära siffror i reella termer; det nedsänkta nummer som följer valutaindikatorn anger basåret.

Figur 7: CAPEX per teknik (md€$_{2020}$, odiskonterade summor), scenarier för direkt elektrifiering (DELS) och utökad PtX (PTXS)



Obs: Investeringar i kärnkraftskapacitet åren 2021–2025 avser Olkiluoto 3 och tidpunkten matchas med den förväntade starten av kommersiell verksamhet (dvs. år 2022)
Källa: resultat från CL-kraftförsörjningsmodellen av Compass Lexecon

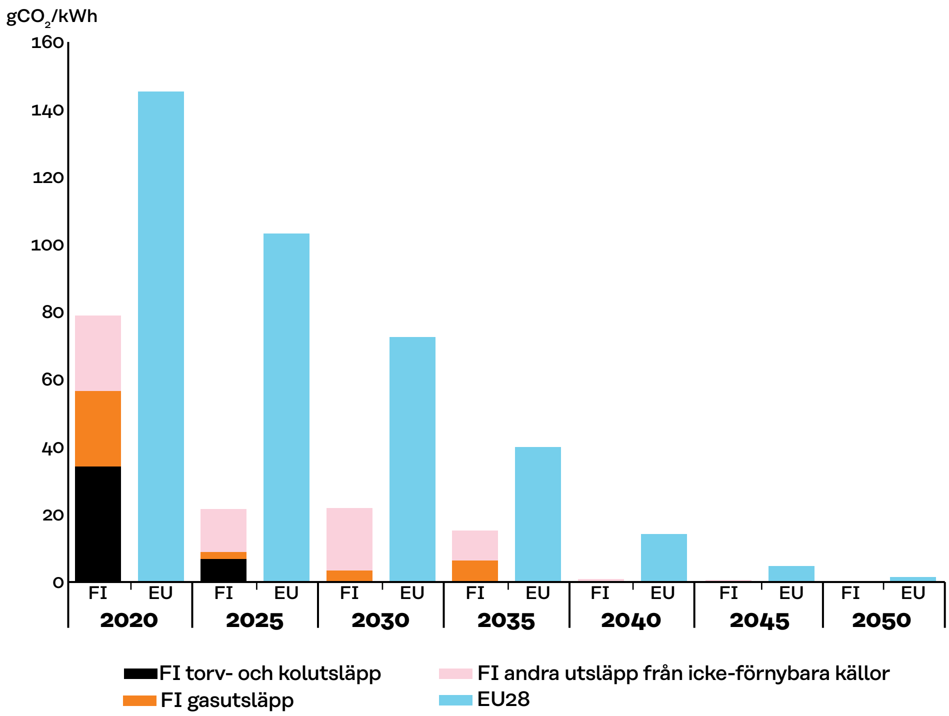
Baserat på Fingrids (2021) scenarier uppskattades investeringsbehovet i det **inhemska överföringsnätet** (utöver Fingrids nuvarande plan på 2 miljarder €$_{2020}$) för att tillgodose ytterligare efterfrågan och produktion i linje med de två scenarierna till mellan 1,5 och 3 miljarder €$_{2020}$ under 2020 till 2050 (odiskonterade summor). Dessutom skulle ytterligare investeringar på cirka 0,9 miljarder €$_{2020}$för åren 2020–2035 och cirka 2,6 miljarder €€$_{2020}$ för åren 2035–2050 (odiskonterade summor) krävas för att utöka **sammankopplingskapaciteten** i linje med antagandena i scenarierna.

Storskalig elektrifiering förväntas inte kräva ytterligare investeringar i **distributionsnäten** eftersom kapacitetsutökningar i allmänhet täcks av investeringar för ombyggnad och uppdateringar som krävs regelbundet.

Utsläpp från elsektorn

Båda scenarierna skulle nästan eliminera koldioxidutsläppen från elsektorn redan år 2040. Banan för minskade koldioxidutsläpp i Finland i båda scenarierna skulle därmed ligga långt före EU-genomsnittet (Figur 8). Medan scenarierna resulterar i relativt stabila specifika utsläpp (gCO_2/kWh) mellan 2025 och 2030, ökar produktionen av koldioxidsnål elektricitet med nästan en tredjedel (Figur 8).

Figur 8: Koldioxidinnehåll i finsk och europeisk elektricitet (gCO_2/kWh), scenariot för direkt elektrifiering

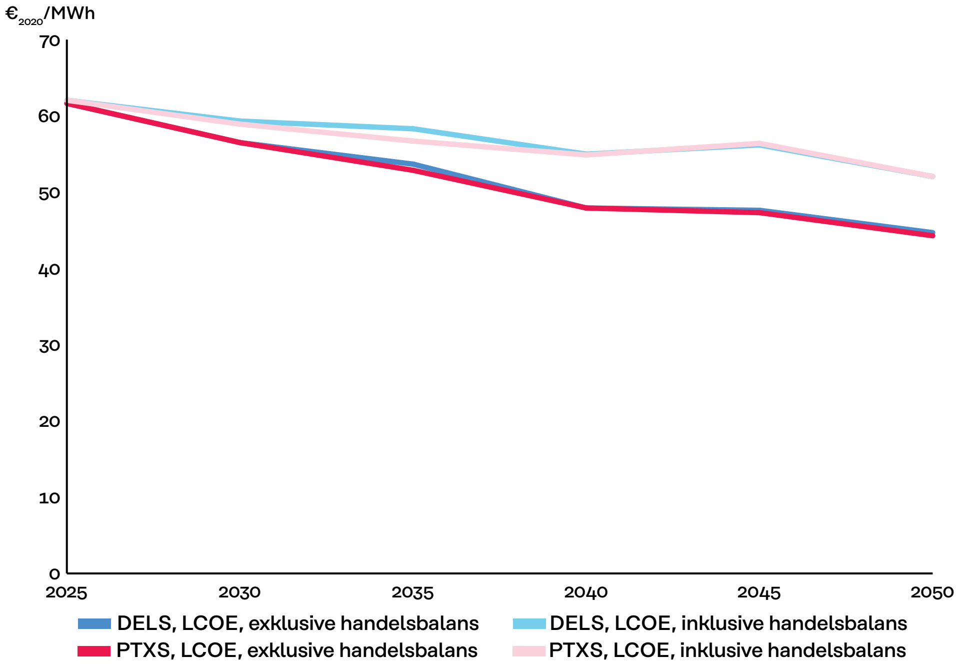


Källa: resultat från CL-kraftförsörjningsmodellen av Compass Lexecon

Kostnader och priser

I båda scenarierna kommer de totala elproduktionskostnaderna i Finland (LCOE) att minska med närmare 30 % år 2050 jämfört med 2020. När importen tas med i beräkningen kommer kostnaden för den elektricitet som förbrukas i Finland år 2050 fortfarande att sjunka med 20 % jämfört med nuläget (Figur 9).

Figur 9: Total kraftsystemkostnad per MWh, LCOE, (€$_{2020}$/MWh/år)

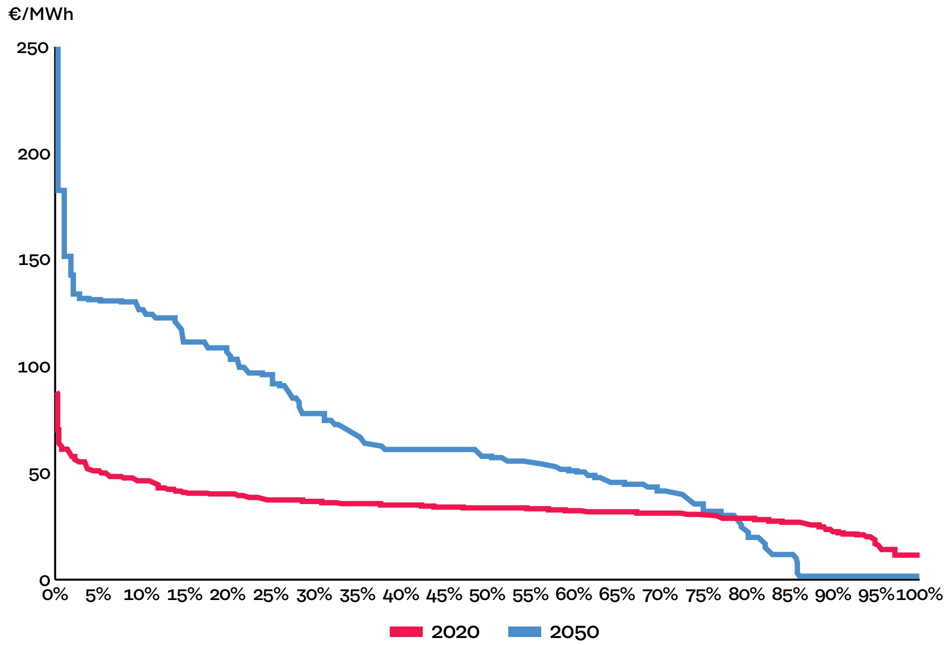


Obs: LCOE, levelized cost of electricity, avser nivåiserad elkostnad (dvs. kapitalkostnader, drifts- och underhållskostnader och bränslekostnader, om tillämpligt, dividerat med årliga produktionsvolymer. Skatter och koldioxidkostnader (ETS) ingår inte). Handelsbalansen är värdet eller kostnaden för nettoimport eller nettoexport.
Källa: resultat från CL-kraftförsörjningsmodellen av Compass Lexecon

Större intermittent penetration av förnybar energi kommer att förändra dynamiken i det finska partipriset[8] på energi. Antalet timmar med höga men också låga till nollpriser jämfört med nuläget kommer att öka betydligt (Figur 10) och därmed höja det årliga genomsnittliga [9]verkliga partipriset på energi med cirka 86 % år 2050 jämfört med nuläget.

8 Dvs. elpriset på elmarknader. Detta pris fastställs i allmänhet genom att beakta de rörliga produktionskostnaderna för den marginella produktionsenheten som krävs för att svara mot efterfrågan under en viss timme. Det marginella kostnadsbaserade partipriset skiljer sig i allmänhet från de genomsnittliga totalkostnaderna för elproduktion som uttrycks i LCOE.
9 Dvs. genomsnittet av alla 8 760 timmar på året och därigenom bortsett från faktiska konsumentlastmönster och effekterna av flexibilitet på efterfrågesidan för att undvika uttag under de dyraste timmarna.

Figur 10: Varaktighetskurvor för partipriser i scenariot för direkt elektrifiering (€/MWh)



Källa: resultat från CL-kraftförsörjningsmodellen av Compass Lexecon

Ur ett slutanvändarperspektiv balanseras ökad elanvändning – och tillhörande kostnader – av minskad total energianvändning på grund av effektivitetsvinster och elektrifiering som minskar användningen av fossila bränslen.

Två känslighetsanalyser undersöker effekterna av begränsningar i vindkraftsutbyggnad och möjligheten till flexibilitet på efterfrågesidan.

Den första känslighetsanalysen fokuserar på **potential för vindkraft på land** och begränsar det till 25 GW (i stället för max. 54 GW i grundantagandet). Detta förskjuter den kostnadsoptimerade produktionskapacitetsmixen i scenariot för direkt elektrifiering avsevärt mot mer kärnkraftskapacitet (+4,5 GW år 2050) och batterier samtidigt som det minskar P2G2P-lagring på längre sikt eftersom kärnkraftsproduktion ger flexibilitet på längre sikt. Ökad import leder till något minskade inhemska systemkostnader i Finland, men de totala kostnaderna ökar jämfört med grundscenariot när denna import är medräknad.

Den andra känslighetsanalysen fokuserar på användningen av **flexibilitet på efterfrågesidan** (DSF) genom att nästan halvera potentialen jämfört med grundantagandena. Denna reducerade DSF-tillgänglighet ökar behovet av flexibilitet på utbudssidan (lagring) samt ytterligare produktionskapacitet för att täcka lagringsförluster – något som leder till väsentligt högre totala system- och elkostnader. Den begränsade tillgången på gaslagringskapacitet och lämpliga platser i Finland understryker vikten av att använda DSF så mycket som möjligt. Ytterligare incitament och information samt bred distribution av respektive digitaliseringslösningar kan krävas för att säkerställa att DSF-potentialen faktiskt görs tillgänglig.

Slutsatser och följande steg

Det är möjligt att uppnå de ambitiösa klimat- och energimålen (kolneutralitet år 2035 och fullständig utfasning av fossila bränslen år 2050) med den tilltänkta tekniken, utan alltför optimistiska energieffektivitetsvinster eller långvarig ökning av biomassaanvändning som äventyrar kolsänkan i de finska skogarna. I stället skulle stark direkt och indirekt sektorövergripande elektrifiering medföra att de flesta av de historiska utsläppen av växthusgaser kan undvikas. De återstående utsläppen av växthusgaser från jordbruk, industriprocesser och avfall år 2050 kompenseras med hjälp av negativa utsläpp från införandet av bioenergi med koldioxidinfångning och lagring (BECCS).

Rollen för indirekt elektrifiering med elbaserat väte och andra syntetiska bränslen (”power-to-X”, PtX) i Finlands framtida energisystem behandlas särskilt här. Vi visar att PtX-bränslen kan vara konkurrenskraftiga inom segmentet för tunga transporter, och inom industrin kan PtX möjliggöra fullständig utfasning av fossila bränslen i industriprocesser som är svåra att elektrifiera. I industriell användning av fossila bränslen för annat än energi, framför allt kemiska råvaror, kan koldioxidutsläppen minskas med hjälp av bioenergi, till exempel med råvaror baserade på industrins spillvätskor och power-to-X-bränslen samt ökad återvinning.

Studien visar att den största kostnadseffektiva källan till koldioxidsnål kraft i Finland under de angivna scenarierna skulle vara vindkraft på land med ett starkt stöd av flexibilitetskällor på efterfrågesidan. Vi konstaterar att underlåtenhet att utveckla hela den ekonomiska potentialen i vindkraft på land eller flexibilitet på efterfrågesidan har stora och kostsamma konsekvenser för det finska kraftsystemet. Betydande ny inhemsk flexibilitet på utbudssidan kommer att krävas för att balansera den ökande intermittenta vindkraftsproduktionen och ersätta avvecklad produktion med fossila bränslen. Specifikt kan kraft-till-gas-till-kraft-kapacitet (P2G2P) ge flexibilitet veckovis och på längre sikt och batterier kan medföra flexibilitet under dagen för att balansera vindkraftsproduktion, särskilt från och med år 2040.

Elektrifiering kommer också att ha en stor inverkan på överföringsnätet och ökar behovet av att bygga ut överföringskapaciteten. Distributionsnäten behöver endast en begränsad kapacitetsutökning, men hantering av efterfrågetoppar skulle bli ytterst viktig.

I båda scenarierna kommer de totala elproduktionskostnaderna i Finland (LCOE) att minska med närmare 30 % år 2050 jämfört med nuläget. Avslutningsvis visar studien att ökad elanvändning – och tillhörande kostnader – balanseras av effektivitetsvinster och elektrifiering som minskar användningen av fossila bränslen.

Vi identifierar flera viktiga **följande steg** för att möjliggöra en kostnadseffektiv utfasning av fossila bränslen i Finland baserat på resultaten med hjälp av kvantitativ modellering och kvalitativ analys, samt genom inspel från olika intressenter. För industrin bör alternativ för införande av nödvändiga incitament för kolneutrala processer och råvaror undersökas på nationell nivå och EU-nivå. System för incitament till negativa utsläpp bör analyseras och en motsvarande marknad etableras på nationell nivå eller EU-nivå. En gynnsam och konkurrenskraftig investeringsmiljö för industriella aktörer som syftar till investeringar i utsläppsminskningar bör säkerställas, inklusive snabba tillståndsprocesser och förutsägbar reglering. Ett omfattande regelverk på EU-nivå som stöder uppbyggnaden av en väteindustri i Finland, inklusive infrastruktur, bör utvecklas. Finland bör också utarbeta en tydlig nationell vätestrategi.

Vindkraft kommer att ha en betydande roll i Finlands framtida kraftproduktionsmix. Åtgärder för att strukturellt minska effekten av Försvarsmaktens krav gällande utbyggnaden av vindkraftskapacitet bör undersökas genom att till exempel definiera områden med militära begränsningar på utbyggnad av vindkraft i förväg, mer transparenta diskussioner om byggplaner samt forskning och utveckling av lösningar för att begränsa störningar mellan radaranläggningar och vindkraftverk. Åtgärder för att minska längden på tillståndsprocesser för vindkraftsparker (t.ex. att eventuellt öka kapaciteten för beviljande av tillstånd inom den offentliga förvaltningen eller domstolarnas resurser för handläggning av besvär) bör utforskas. För att säkerställa tillgången till flexibilitet inom utbud och efterfrågan i framtiden bör tillräckliga investeringsincitament regelbundet ses över, och vid behov bör alternativ för att förbättra dessa incitament undersökas.

Som alla framåtblickande studier och alla modelleringar innehåller även det aktuella arbetet **begränsningar och osäkerhetsfaktorer,** vilka ofta är relaterade till de underliggande antagandena. Om till exempel energieffektivitetsvinsterna på grund av tekniska framsteg och elektrifiering inte förverkligas, skulle detta leda till större efterfrågan på slutlig energi, en långsammare takt i utfasningen av fossila bränslen och en annorlunda energibalans. På samma sätt, om de framtida teknikkostnaderna avviker avsevärt från de antaganden som används här – till exempel när det gäller vindkraft till havs eller kärnkraft – kan detta leda till förändringar i den kostnadseffektiva energimixen och vägen mot minskade koldioxidutsläpp. Avvikelser i tillgängligheten och kostnaderna för hållbar biomassa för energianvändning kan också leda till betydande variationer på vägen mot minskade koldioxidutsläpp. Dessa osäkerhetsfaktorer bör övervakas och effekterna av eventuella avvikelser från de nuvarande antagandena bör analyseras ytterligare. **Framtida forskning** bör noggrant bedöma det tekniska regelverket och utformningen av politiken gällande strategisk infrastruktur för att säkerställa en kostnadseffektiv och säker energiförsörjning i Finland.

1 Introduction and emission targets

In 2019, the Finnish Government has set a new climate target whereby Finland would be carbon neutral by 2035. New longer-term targets will be set in the newly reformed Climate Change Act. Existing measures are insufficient to reach the new climate targets, but the currently updated National Energy and Climate Strategy will be in line with the 2035 target. Previous Finnish energy system studies – including those commissioned by Sitra – have indicated the importance of electrifying energy use to achieve deep decarbonisation. There is, however, still significant uncertainty about the structure of and the pathway towards a decarbonised Finnish electricity system.

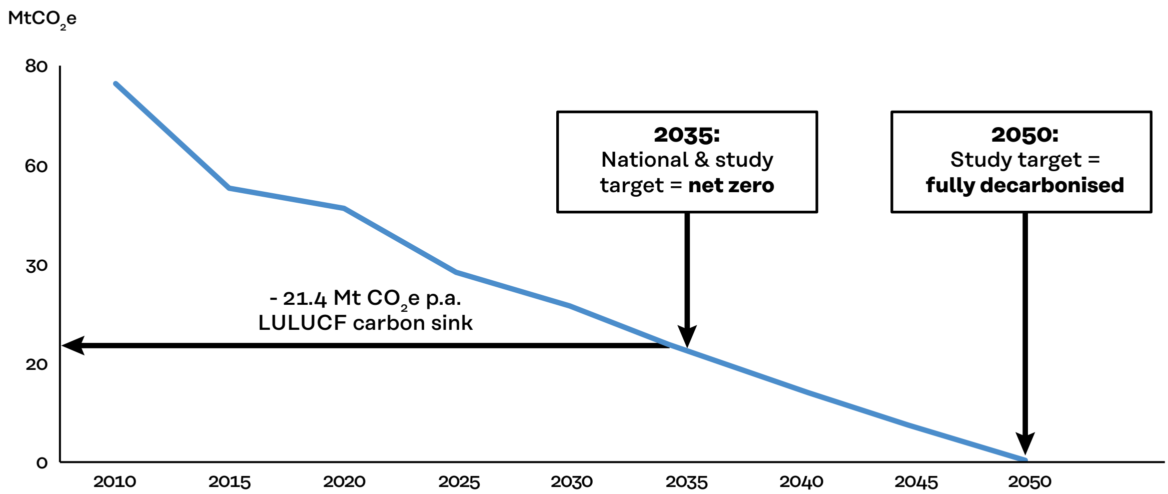
Aim of this study

This study provides a holistic view of electrification and decarbonisation in Finland and identifies enablers, pain points and policy recommendations. Carbon neutrality should be reached by 2035, and full decarbonisation by 2050.

In considering the future Finnish demand for energy on one side, and carbon-free ways to satisfy this demand, we map out the most cost efficient and feasible way to decarbonisation in Finland.

The study examines the current Finnish energy system, the required security of supply, and available local resources. In particular, attention is paid to newer techno-

Figure 11: Targets for domestic gross CO_2 equivalent emissions [Mt/a] in Finland excluding LULUCF



Notes: LULUCF refers to Land Use, Land Use Change and Forestry
Source: Compass Lexecon; LULUCF carbon sink size based on (Seppälä J. , Savolainen, Sironen, Soimakallio, & Ollikainen, 2019)

logical solutions like demand flexibility as well as hydrogen and other synthetic fuels.

Subsequently, key enablers but also pain points and bottlenecks are identified. We also assess whether the identified changes are likely to materialise under the current market mechanisms and policy frameworks.

Current emissions, carbon neutrality and decarbonisation

Figure 11 shows the starting point, current emissions in Mt of CO_2e and gross CO_2 equivalent emission targets for 2035 and 2050 in Finland. Finland aims to achieve the 2035 interim target of carbon neutrality of the Finnish energy system and full decarbonisation by 2050.

Carbon neutrality means that Finland as a whole does not emit more carbon than it absorbs as a carbon sink. The 2035 target is achieved by relying on the carbon sink resulting from Land Use, Land Use Change, and Forestry (LULUCF), assumed to be kept at minimum 21 Mt. So, starting from its current emission level of roughly 53 Mt of CO_2e, Finland would have to reduce its greenhouse gas emissions to 21 Mt.

Full decarbonisation by 2050 would mean that Finland will decrease its carbon emissions to zero. Remaining greenhouse gas (GHG) emissions from agriculture, industrial processes, and waste would have to be compensated by negative emissions from the deployment of BECCS (bioenergy with carbon capture and storage).

Report structure:

Section 2 presents details of the methodology for the energy and power system modelling, as well as for the qualitative analysis on stakeholder inputs. It also describes our scenarios and sensitivities.

Section 3 focuses on the demand side where energy end-uses and ways to decarbonise these are assessed in detail.

Section 4 addresses the electricity supply side, covering the evolution of demand, capacity new build, power price dynamics, power grids, and security of supply.

Section 5 concludes and offers recommendations for next steps.

Appendices A-D provide details on modelling, assumptions, and stakeholder involvement.

2 Overview of methodology, scenarios, and sensitivities

This section presents an overview of the current state of Finnish energy system studies and the methodologies we use in this study, followed by a detailed description of the developed scenarios and sensitivities. It concludes with a discussion of the limitations of the study.

2.1 Current Finnish energy sector studies leave room for genuine contributions of this study

The recent policy target of **Finnish carbon neutrality by 2035** features in several Finnish energy system studies including Fingrid (2021), Forsman, et al. (2021), Koljonen, et al. (2020), Seppälä, et al. (2019) and Lund, et al. (2021). While these studies provide important insights, some gaps remain, allowing this study to make its genuine contribution to the ongoing debate about the future of the Finnish energy system.

We now look at the main similarities and differences of recent Finnish energy system studies and an outline of existing gaps that are closed by this study.

Similarities in the scenarios developed in recent Finnish energy system studies:

— aiming for at least 80% **greenhouse gas emission reduction** by 2050 compared to 1990 – in line with the 2015 Climate Change Act (currently being updated);
— recognising **electrification** as being the key tool of decarbonisation in the industrial, transport and heating sectors, particularly for **passenger cars** where electrification is usually seen to be fast (Forsman, et al., 2021; Koljonen, et al., 2020; Seppälä, et al., 2019) driven by speedy deployment of EVs (EV), reaching over 700 000 by 2030 (compared to ~50 000 in 2020) and growing to up to 2.4 million by 2050 (Koljonen, et al., 2020);
— assuming a significant increase in renewable energy generation (particularly **wind and solar power**), albeit with widely varying capacity and generation shares across the studies;
— using the phase-out of **coal** and the reduction of **peat** usage to quickly decrease emissions;
— seeing a largely unchanged role for Finnish **hydro power**;
— attaching continued importance to **district heating** while expecting a decline in CHP usage due to the phase-out of coal and peat, and CHP's partial replacement with heat-only biomass boilers and heat pumps.

Important differences among the recent Finnish energy studies are often driven by scenario assumptions, particularly regarding:

— the important segment of **industrial demand** electrification; electricity demand is clearly the lowest in Koljonen, et al. (2020) and in Fingrid's (2021) *Sähkö vientiin*-scenario – partly due to the low growth rate in energy intensive industries in combination with low electrification rates. Fingrid's (2021) *Ilmastoneutraali kasvu*-scenario and Lund, et al. (2021) *Äärimmäinen sähköistäminen*-scenario on the other hand presents very significant growth of new energy intensive industry in Finland, leading to a near doubling of electricity consumption compared to Koljonen, et al. (2020).

— future **wind generation** (onshore & offshore), which varies widely between recently modelled scenarios:
  - Forsman et al. (2021) assume ~40 TWh wind generation in 2040;
  - Seppälä et al. (2019) assume slightly below 30 TWh wind generation in 2040;
  - Fingrid (2021) presents a wide range of wind generation assumptions: 41 TWh to 92 TWh in 2035 and 52 TWh to 181 TWh in 2045;
  - Lund, et al. (2021) assumes wind generation to be in range of about 90 to 150 TWh by 2050;
  - Koljonen, et al. (2020) finally show wind generation at ~20 TWh in 2040 and ~40 TWh by 2050.

— **nuclear capacities post 2040** showing broad variation (ranging from 1.9 GW to 5.6 GW) – uncertainty stems from the future of existing nuclear plants after 2035–2040, the potential for new nuclear plants (including Hanhikivi 1), and the potential for smaller modular reactors (SMRs);

— only the newest studies (Fingrid (2021) and Forsman et al. (2021) utilise the 13 **sector-specific decarbonisation roadmaps** published following the publication of the 2035 carbon neutrality target and to support the ongoing process of updating the national energy and climate strategy

Going beyond the recent studies, **the present study contributes to the Finnish energy system debate in the following fields:**

— while respecting the 2035 carbon neutrality target, the two scenarios modelled in this study achieve the even more ambitious target of **full decarbonisation by 2050**;

— most of the existing studies lack a **transition pathway towards 2050**; only Koljonen, et al. (2020) model the energy system transition until 2050, but the study omits a detailed pathway of fuel usages by each sector and subsector. It was also pointed out (Forsman, et al., 2021; Fingrid, 2021) that implementing the findings of the recent sectoral roadmaps into a full energy system analysis leads to considerably higher electricity demand than in Koljonen, et al. (2020). The present study closes these gaps by providing scenario pathways up until 2050 that rely on the sectoral roadmaps and provides sector specific demand evolutions.;

— current studies generally focus either in detail on the electricity sector or provide an overview of all sectors but without the required power sector details. Hourly power dispatch models were used in Forsman, et al. (2021) and Fingrid (2021) to study the power system, but without the link to the other energy Finnish energy sectors. Koljonen, et al. (2020) on the other hand, use a full energy-balance model but without a detailed hourly representation of the power system. Lund, et al. (2021) have utilised simulation model called DEFEND in their analysis, which optimises the energy system based on given preconditions. The present study bridges this methodological gap and **combines a full energy-balance model with a detailed power dispatch model** to capture the entire Finnish energy system and interactions between different energy vectors;

— in contrast to existing studies which use fixed ex-ante assumptions of nuclear capacities, this study applies **cost-optimisation to determine the nuclear capacity** within a comprehensive energy system model;

— none of the recent studies assess total **power system costs**, only Forsman, et al. (2021) include an analysis of future electricity prices up until 2040. This study provides outlooks for both electricity price and power system costs.

2.2. Methodology: The study integrates two state-of the art quantitative energy system models complementing them with qualitative analyses and comprehensive stakeholder involvement

To derive robust results about the cost-efficient electrification in Finland, this study relies on a combination of quantitative and qualitative methodologies, which are presented in Figure 12. The methodology is further described in the two next sections.

2.2.1 Quantitative modelling integrated an annual full energy balance model with an hourly dispatch model

The **quantitative methodology** is based on the integration of two state-of-the-art energy sector models:

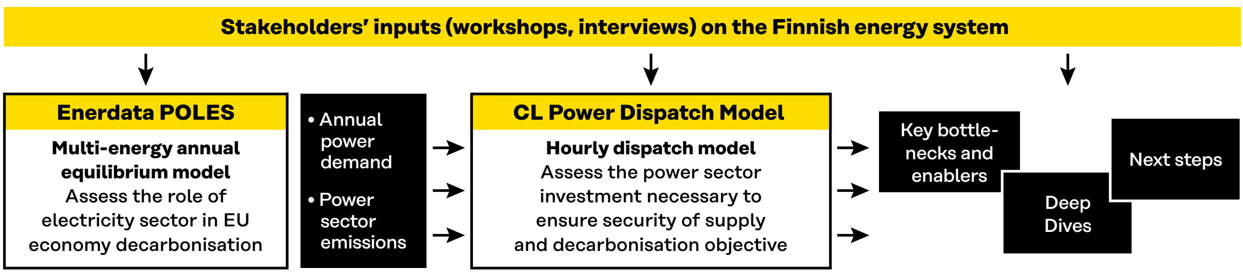
— the POLES-Enerdata full-energy balance model and

— the Compass Lexecon (CL) power dispatch model.

The **POLES-Enerdata** model is a recognised multi-issue energy **simulation model with optimising** features (similar to the PRIMES model used by the European Commission). It relies on national energy balances combined with economic, policy, and technological scenarios. POLES's geographical coverage includes the EU28 countries with a complete modelling from upstream production through to end-user demand. POLES applies a partial equilibrium simulation of the energy sector. The simulation process uses dynamic year-by-year recursive modelling, with endogenous international energy prices and lagged adjustments of supply and demand. POLES thereby models permanent inter-technology competition, with dynamically changing attributes for each technology to derive annual energy production, consumption, and greenhouse gas (GHG) emission pathways up to 2050.

In the context of this study POLES-Enerdata was used to calculate a cost-efficient equilibrium by using specific modelling levers. As POLES is not a pure optimisation model (i.e. with an objective function to minimise system costs), modelling parameters impacting all sectors and fuels similarly were applied, with the objective of reaching a specified constraint. The most straightforward example of these parameters is the **carbon shadow price.** This gives a value to the decarbonisation effort by internalising the GHG emissions as negative externalities in the fossil fuel prices, based on their respective emission factors. Providing the same price signal to all sectors, leads to the resulting emission reductions happening with a cost-efficient repartition by sectors

Figure 12: Overview of the applied methodology



Source: Compass Lexecon

and fuels. The sectors with the **lower marginal abatement cost** perform higher mitigation efforts than others. The targeted constraints (e.g. emission reductions) are reached progressively using an iterative calibration process, which enables us to find the parameter values leading to results matching the objectives.

The modelling of full energy balances carried out in this study was built following this general principle, to derive the cost-efficient scenarios. The main constraints used were the **GHG emission targets** (carbon neutrality in 2035, full decarbonisation by 2050). The model was calibrated to reach these objectives with cost-efficient results. The results were benchmarked to external studies (Appendix C), and sometimes adjusted to ensure consistency, notably accounting for the specificities of the Finnish energy system (see the study's limitations below). More detail on the POLES-Enerdata model can be found in Appendix A.

Based on the annual modelling results provided by the POLES model on the full energy equilibrium of Finland (i.e. the electricity demand and the permissible electricity sector emissions), **Compass Lexecon's (CL) pan-European hourly power dispatch model** develops a cost efficient expansion of the – Finnish and European – electricity generation and storage capacities by co-optimising their expansion and hourly dispatch of dispatchable capacities. The target of this optimisation is to find the power sector evolution leading to minimal total cost (discounted[1] to today). The costs included comprise capital costs (annualised CAPEX), operating & maintenance costs and fuel costs (where applicable) of the generation and storage park. The optimisation considers imposed limitations (e.g. emission targets, capacity potentials, interconnection capacities, capacity margins to ensure security of supply) to derive the necessary capacity build-up to satisfy electricity demand. The hourly dispatch optimisation thereby models the competitive situation among the various capacities active on the individual European markets in determining the resulting dispatch required to satisfy load requirements.

The CL power dispatch model is implemented in the commercial modelling platform Plexos® Integrated Energy Model and is based on Compass Lexecon's comprehensive set of data and assumptions on the European power market. The geographic scope of the CL power dispatch model is the EU-28 countries as well as Switzerland, Norway, the Balkans, and Turkey. More details on the CL power dispatch model can be found in Appendix B.

2.2.2 Qualitative analyses supported and complemented the quantitative modelling

Qualitative methods were applied to support the quantitative modelling and to develop the remaining study results. And extensive literature review was applied to assess

- the status of Finnish energy system studies (section 2.1);
- assumptions underlying the demand evolution of all sectors to ensure the latest sector-specific knowledge was used in the modelling and analysis (appendix A.6);
- assumptions underlying the modelling of the supply side (section 4.1.1).

The latest national sources used in this study are referenced in Appendix C. The external sector-specific sources included carbon neutrality roadmaps and the latest decarbonisation studies, further supplemented by the stakeholder inputs received

1 A rate of 5% was assumed.

during the workshops and follow-up interviews.

An integral part of this study is the identification of **key bottlenecks and enablers** of cost-efficient electrification, which is tightly interlinked with the **next steps recommendations**. These results were developed as follows:

- by identifying the transition needed based on a comparison of modelling results with the current situation;
- by identifying, using expert knowledge and discussions with stakeholders and Sitra, potential bottlenecks for the projected transition and enablers to mitigate bottlenecks and to recommend next steps.

The results of this analysis are reflected in the individual sections devoted to the main bottlenecks and enablers related to specific sectors (industry, transport, buildings & services, power generation, transmission, and distribution grids) and topic areas (supply-side flexibility, demand-side flexibility).

2.2.3 The study profited from comprehensive stakeholder involvement in various forms

The development of the study was accompanied by comprehensive stakeholder involvement. In a first phase five stakeholder workshops on modelling inputs and assumptions were held. Interim results of the quantitative modelling were discussed in a set of three stakeholder workshops. During these eight workshops (all in the form of video calls) participants could share their insights in written and oral statements, and following the workshops online questionnaires were sent to all stakeholders to collect additional inputs. After the workshops on modelling outputs, a set of five one-on-one interviews with key stakeholders were held to support the identification of bottlenecks and mitigation measures and clarify remaining questions. Finally, the study results were presented to all stakeholders in a final workshop ahead of the study report's finalisation.

The full list of institutions participating in the stakeholders involvement process is provided in Appendix D.

2.3 Scenarios developed and sensitivity analysis performed

The quantitative modelling exercise is carried out across two **scenarios each using a set of baseline assumptions and two additional sensitivities per scenario**. Figure 13 presents how these baseline assumptions and sensitivities are applied to the scenarios.

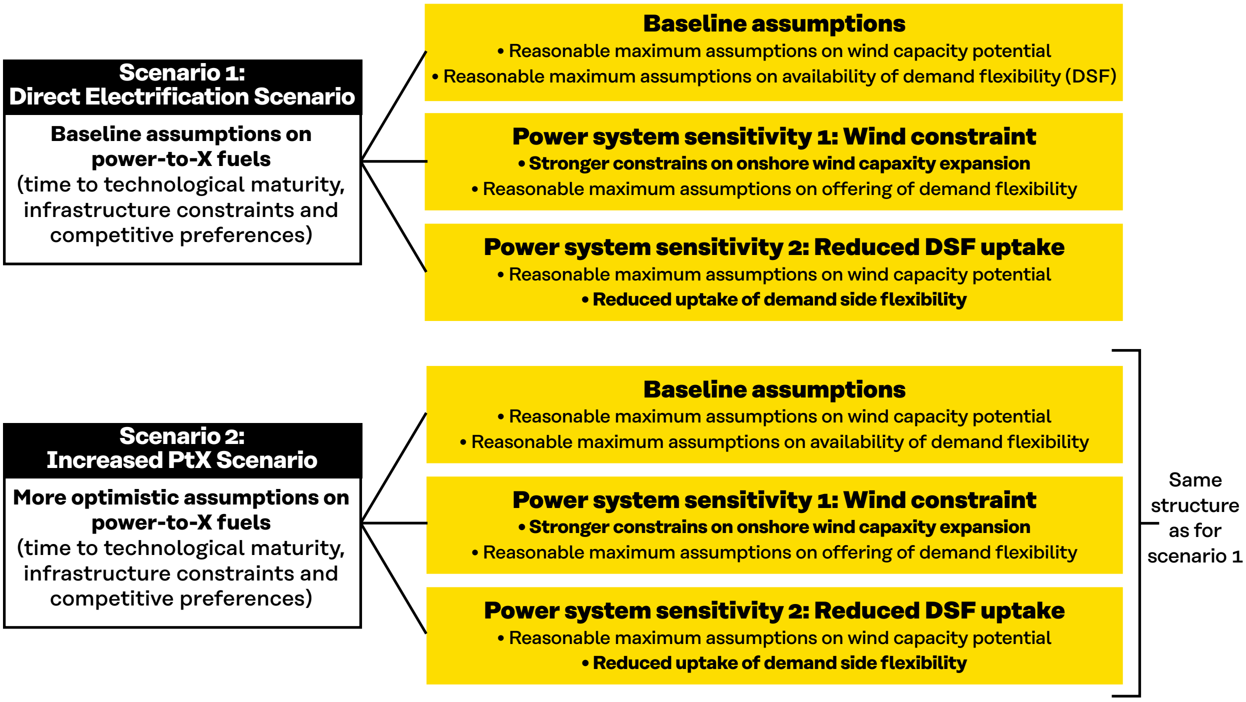
This study determines the cost-efficient way for decarbonising the Finnish energy system by developing and comparing two alternative scenarios:

- Scenario 1 – Direct Electrification Scenario (DELS)
- Scenario 2 – Increased PtX Scenario (PTXS)

The two scenarios are based on assumptions regarding commodity prices, technology costs, sectoral demand, macroeconomic and demographic development. **Key differences and similarities** between the scenarios are presented below, and more detail can be found in Appendix A.

The **key differences** between the two scenarios stem from the assumptions about the usage of and competitive preference for power-to-X (PtX) fuels. While the Direct Electrification Scenario uses baseline assumptions on time to reach technological maturity and infrastructure constraints for PtX-fuels, the Increased PtX Scenario applies slightly more optimistic assumptions. The resulting difference in PtX usage between the two scenarios then mainly affects the industry and transport sectors, as summarised in Table 1. Both scenarios also assume that sufficient sustainable bioenergy is available

Figure 13: Scenarios developed, and sensitivity analysis performed



Source: Compass Lexecon

Table 1: Selected assumptions differences between the scenarios

Scenario assumptions	1. Direct Electrification Scenario	2. Increased PtX Scenario
Industry	**Baseline usage of PtX:** Energetic use of fossil fuels largely replaced by electrification and bioenergy. Fossil fuels as feedstock largely replaced with bioenergy, recycled materials, and PtX	**Higher PtX use:** Energetic use of fossil fuels in industry sector partly replaced with PtX fuels. Increased usage of PtX as feedstock (chemical).
Transport	**Baseline usage of PtX:** Strong direct electrification of vehicle fleet Additional use of synthetic fuels, biogas, and biofuels	**Higher PtX use:** Additional use of synthetic fuels and hydrogen – particular in heavy trucks; less use of bioenergy

Source: Compass Lexecon

to supply all its end-use, which is higher in the Direct Electrification scenario, especially in the medium term.

Both scenarios contain **similar assumptions** about the techno-economic costs in different sectors. See specific power sector assumptions, including costs, in the following sub-section 4.1.1. Other sectors' costs, such as for industry, buildings, and transport, are based on multiple national and international sources (Appendix A.5). For example, purchase cost parity between EVs and internal combustion engines (ICEs) is assumed to be achieved in 2025. With respect to the energy policy assumptions, it is assumed in both scenarios that the Finnish decarbonisation targets for 2035 (net zero) and 2050 (full decarbonisation) are achieved as well as the EU-wide target of at least 55% GHG emission reduction by 2030 and net zero in 2050. The carbon shadow price[2] used to match these targets, as per the methodology described in paragraph 2.2.1, reached around 232 $€_{15}$/tCO_2 by 2035 and 450 $€_{15}$/tCO_2 by 2050 in the Direct Electrification scenario, and around 267 $€_{15}$/tCO_2 by 2035 and 517 $€_{15}$/tCO_2 by 2050 in the Increased PtX scenario.

The cost-optimal evolution of the electricity sector is derived based on the results of the energy balance results for both scenarios (DELS and PTXS). Besides the application of a baseline set of assumptions for the electricity sector in each scenario, our study also develops two **sensitivity analysis** for each scenario:

— Sensitivity 1: Limited onshore wind capacity expansion;
— Sensitivity 2: Limited uptake of demand side flexibility.

Sensitivity 1 is designed to reflect the potential **bottleneck of not being able to develop the onshore wind capacity to its full economic potential** due to, for example, the military radar restrictions in Eastern Finland and/or local opposition (NIMBY, Not In My Back Yard). Compared to the baseline assumption of 54 GW for onshore and 25 GW for offshore wind power potential in Finland, Sensitivity 1 reduces the onshore potential to 25 GW. The baseline wind potentials are derived from (Fingrid, 2021) but note that these do not become binding, i.e. reaching their pre-set limits, in the cost-optimal (baseline) scenarios. Details and results of this wind sensitivity analysis are outlined in section 4.9.

Sensitivity 2 is designed to reflect the **bottleneck of not developing the full economic potential of demand side flexibility**. Compared to the baseline assumption in the Direct Electrification Scenario where DSR capacity is equal to 12 GW in 2050, the sensitivity assumes only 6.5 GW. Similarly, compared to the baseline assumption in the increased PtX scenario where DSR capacity is equal to 14.7 GW, the sensitivity assumes only 7.8 GW. Details and results of this demand side flexibility sensitivity analysis are outlined in section 4.10.

2.4 This study's limitations

The POLES-Enerdata model enables computing robust results for the full energy balances of the Finnish energy system up to 2050. Like all models, however, the POLES-Enerdata model also has its limitations. The most impactful ones are presented below.

To begin, the POLES-Enerdata model is not focused only on Finland, but rather has a global coverage, with a country resolution. This enables us to capture global and regional effects such as commodity price evolution, learning curves for new technologies, etc. On the downside, this also means that the model is not tailor-made for a country specific context. Also, it covers the total energy systems, including energy supply (production, transformations) and demand (by sector). Therefore, the sectoral breakdown and technological resolution of the model cannot be as precise as a model dedicated to a specific sector could be (see Appendix A for more details). The industrial sub-sector breakdown (Steel, Chemicals, Non-metallic minerals, Other) does not separately represent the forest and paper industry, which is modelled as part of the "Other" aggregate. Second, the district heating supply is modelled in a simplified way. It enables us to get aggregate results for

2 Note: the values provided correspond to a carbon price signal, which measures the value of GHG emission abatements corresponding to the set targets. It would correspond in practice to a wide range of measures and not only to an actual carbon price. The provided values can therefore not at all be compared to the EU ETS market price or to a carbon taxation.

energy carriers used to produce district heat (fossil, bioenergy, electricity via heat pumps), but does not include additional considerations and constraints, such as the localisation of heat networks, source of heat for heat pumps (ground heat vs. seawater heat vs. waste heat), etc. And finally, the modelling of bioenergy is also aggregated, as the model only represents a "bioenergy" carrier and not the corresponding types of bioenergy (wood, biofuels, etc.).

To mitigate these limitations, the modelling results were compared to and improved using external studies and analysis (see Appendix C). For instance, the industrial energy consumption evolution was elaborated accounting for the industry roadmaps, including considerations specific to the paper and forest industries. As another example, the bioenergy consumption projected by the POLES-Enerdata model was subject to an ex-post analysis to calculate the share of each bioenergy types in the total, also ensuring consistency.

In addition, since the POLES-Enerdata model does not endogenously cover LULUCF and the non-energy related agricultural emissions, the following assumptions have been made regarding their respective evolutions: 1. **LULUCF GHG emissions** are assumed to be constant at -21.4 MtCO2e; and 2. **Agriculture non-energy related emissions** were derived from Statistics Finland (historical data) and the forecast values from (Koljonen, et al., 2020) in the Jatkuva Kasvu scenario.

The POLES-Enerdata model does also not explicitly cover hydrogen network and storage infrastructure. An estimate of hydrogen transport cost is considered when evaluating the inter-fuel competition, however, the model does not feature a precise representation of the infrastructure and storage needs.

Overall, the POLES-model present some limitations inherent to this type of models, mostly in terms of resolution and lack of country-specific representation. However, the use of external benchmark sources and analysis allowed to ensure the general consistency of the full energy balances results.

The CL power dispatch model also has its limitations.

The optimisation assumes deterministic price, load and RES generation evolutions and respective perfect foresight – which is relevant when assessing energy storages that enable inter-temporal arbitration. To avoid over-optimistic results, only average RES generation profiles were applied in the analysis (see section 4.1.1) and the capacity expansion path considers mark-ups on capacity needs to ensure security of supply also under exceptional circumstances (see section 4.7). Moreover, the resulting system's resilience is assessed specifically for times of low renewable generation (see section 4.7).

For solving both the capacity expansion decision and the hourly dispatch decision for available capacities, certain linearisations are applied in the optimisation to keep calculation times within reasonable limits or to make the model even solvable in the first place. Linearisation necessarily leads to approximation of a problem that is in some aspects of a mixed-integer or otherwise non-linear nature.

Moreover, the CL power dispatch model calculates the price in each price zone as the marginal value of energy delivered in that zone based on the simulated bids of flexible generators. In reality these bids closely follow the estimated short-run variable cost of power generation. Therefore, the estimated clearing prices correspond to the marginal cost of electricity. Such estimation of **electricity prices based on the marginal cost** is reasonable when the capacity margin above the demand is high and there is high competition between generators to serve the demand. The CL power dispatch model therefore omits any price effects from a distorted competition between generators which could be strategically bidding above their short run marginal costs.

Additional limitations of the power system modelling involve choices on the representation of **interconnection capacities**. The cross-border interconnection with Russia is excluded from the model in particular. This concerns mainly the Vyborg line, which is currently in use but without significant renewal would be phased-out after 2030 (Fingrid, 2021). Also, given the historical variations of power flows on the Finnish Russian border due to, for example, market design changes in Russia (Viljainen, et al., 2013), this study takes a conservative approach and explicitly excludes this interconnection rather than making strong assumptions about the flows and line renewal. The impact of the line's renewal can be studied in future power system assessments.

Regarding wind generation, the model differentiates between onshore and offshore wind but does not further diversify between wind locations. While the CL power dispatch model explicitly models cross-border interconnectors and their power flows, **domestic transmission and distribution networks** are not directly modelled[3] – neither is the gas or hydrogen infrastructure required to provide parts of the flexibility to the system. The analysis of impacts of the modelled scenarios on electricity transmission and distribution networks was therefore **performed by LUT University**.

For the distribution networks, previous case studies conducted by LUT University were used to assess the development and future challenges of the networks (Haakana et al., 2018; Lassila et al., 2019; Belonogova et al., 2020). **Distribution network investment costs** were derived from an earlier bottom-up analysis done by LUT University for the Ministry of Economic Affairs and Employment (Partanen, 2018). The earlier distribution network study assessed investments only up to 2035, but it is assumed that already in this period the majority of the needed investments are conducted to allow electrification in the distribution network.

To quantify the **domestic transmission network investments**, this study derived the investments costs from Fingrid (2021), which studied the effects of electrification on the transmission network until 2045. Fingrid's results were reflected in this study's scenarios to derive the needed investments into the domestic transmission network. Despite the described approaches substituting detailed grid modelling, the grid assessment is based on the latest and robust national studies.

Beyond the limitation of the models used, certain topics were outside the scope of this study even though they may influence Finland's path to decarbonisation. Most notably, neither the availability and pricing of materials (e.g. rare earths) required for widespread electrification nor those of sustainable biomass were studied in detail. Their respective availability was therefore rather assumed. Also absent from the study is consideration of breakthrough technologies not yet available on an industrial scale. Finally the study based all calculations on a fixed set of cost and price assumptions (Appendix A and Appendix B) and the results are therefore valid against the background of these assumptions. Further studies on these limitations and uncertainties are recommended.

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3 The exception are offshore grid connection to the mainland grid for offshore wind parks (the respective costs are included in the generator build-up cost assumptions). All other transmission costs (particularly those on the mainland) are not considered in the build-up cost assumptions.

3 Demand side: Cost-efficient decarbonisation of the Finnish energy system requires wide-spread electrification of end-uses

The Direct Electrification Scenario is shown to lead to the most cost-efficient way of decarbonising the Finnish economy. This section presents the essential demand side results for this cost-efficient Direct Electrification Scenario and generally contrasts them with results for the Increased PtX Scenario.

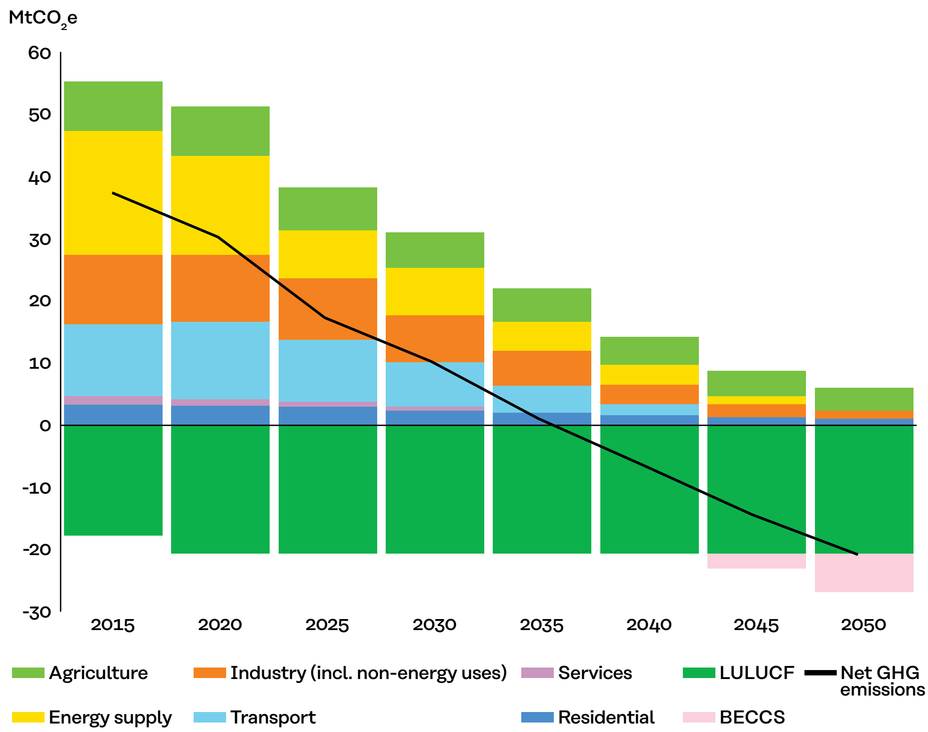
3.1 GHG emission pathways: Both scenarios achieve carbon neutrality by 2035 and full decarbonisation by 2050

Key takeaways

- The two scenarios will lead to carbon neutrality by 2035 and full decarbonisation by 2050.
- By 2050, around 6 $MtCO_2e$ remaining GHG emissions (from agriculture, industrial processes, and waste) will be compensated by negative emissions from BECCS (bioenergy with carbon capture and storage).

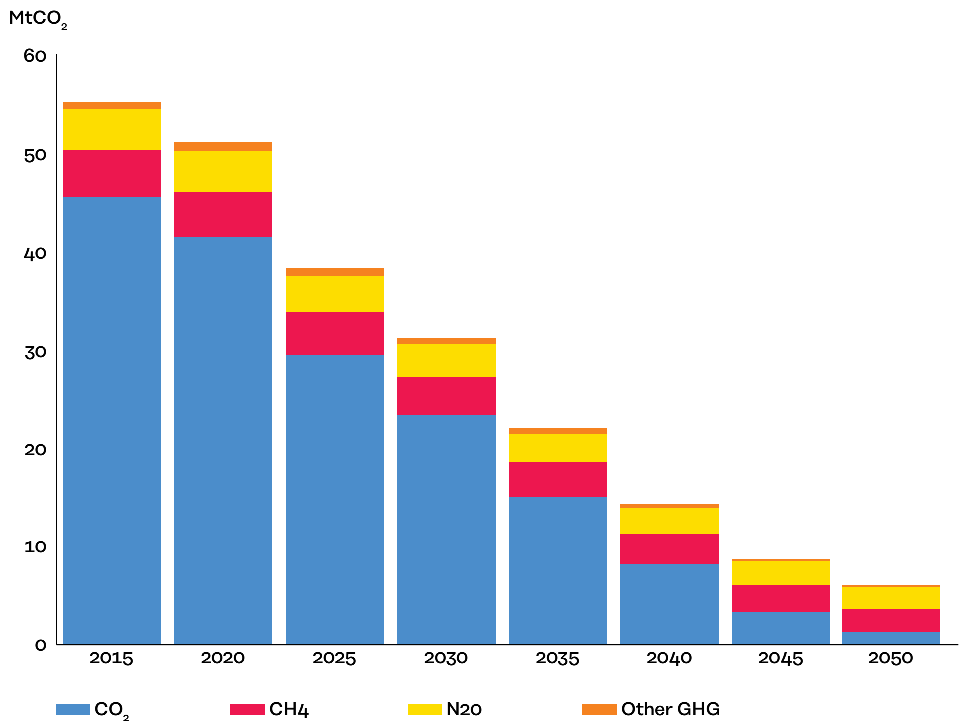
Finland can be carbon neutral by 2035 and fully decarbonised by 2050, thus achieving the respective emission targets. Net GHG emissions, which are illustrated in Figure 14 for the Direct Electrification Scenario, follow a strongly decreasing trend over the period, while two main factors explain this pathway: first, strong electrification of energy end-uses, and second, phasing-out of fossil fuels in the energy production sector.

Figure 14: Net GHG emissions & emissions by sector, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

Figure 15: Evolution of emissions by GHG, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

Under the scenario, the largest emission reductions would be attained in the transport, services, and energy supply sectors, which would achieve zero gross GHG emissions by 2050. Residual gross emissions excluding bioenergy with carbon capture and storage (BECCS) can be found in the agriculture sector (3.8 $MtCO_2e$ in 2050, -52% from 2015), in the industry (1.3 $MtCO_2e$ in 2050, especially industrial processes such as cement production; an overall 88% reduction from 2015), and in the residential sector (0.9 $MtCO_2e$ in 2050, mostly waste; 72% from 2015). While the electricity generation sector would be fully free of fossil fuels by 2050, carbon capture and storage is expected to play a role in the industry, with around 6.1 $MtCO_2e$ carbon removals from BECCS[1] by mid of the century, compensating for the hardest-to-abate remaining gross emissions. As a result, net GHG emissions would reach 21 $MtCO_2e$ in 2050, i.e. the level of the LULUCF carbon sink.

In terms of the individual greenhouse gases, CO_2 currently (2015) accounts for 82% of all gross GHG emissions. As shown in Figure 15, the reduction of CO_2 emissions would be significant until 2050 (97% compared to 2015), while over the same period CH_4 emissions are decreased by 48%, N_2O by 49% and other greenhouse gases (HFC, PFC, SF_6) by 65%.

The GHG emission reduction pathway presented here is in line with the governmental target of carbon neutrality by 2035, with about 1 $MtCO_2e$ net GHG emissions[2] (around 22 $MtCO_2e$ gross GHG emissions, a 60% reduction from 2015 levels), before reaching a full decarbonisation of the Finnish economy by 2050.

3.2 Demand metrics: Final energy intensity declines steadily and electrification increases significantly

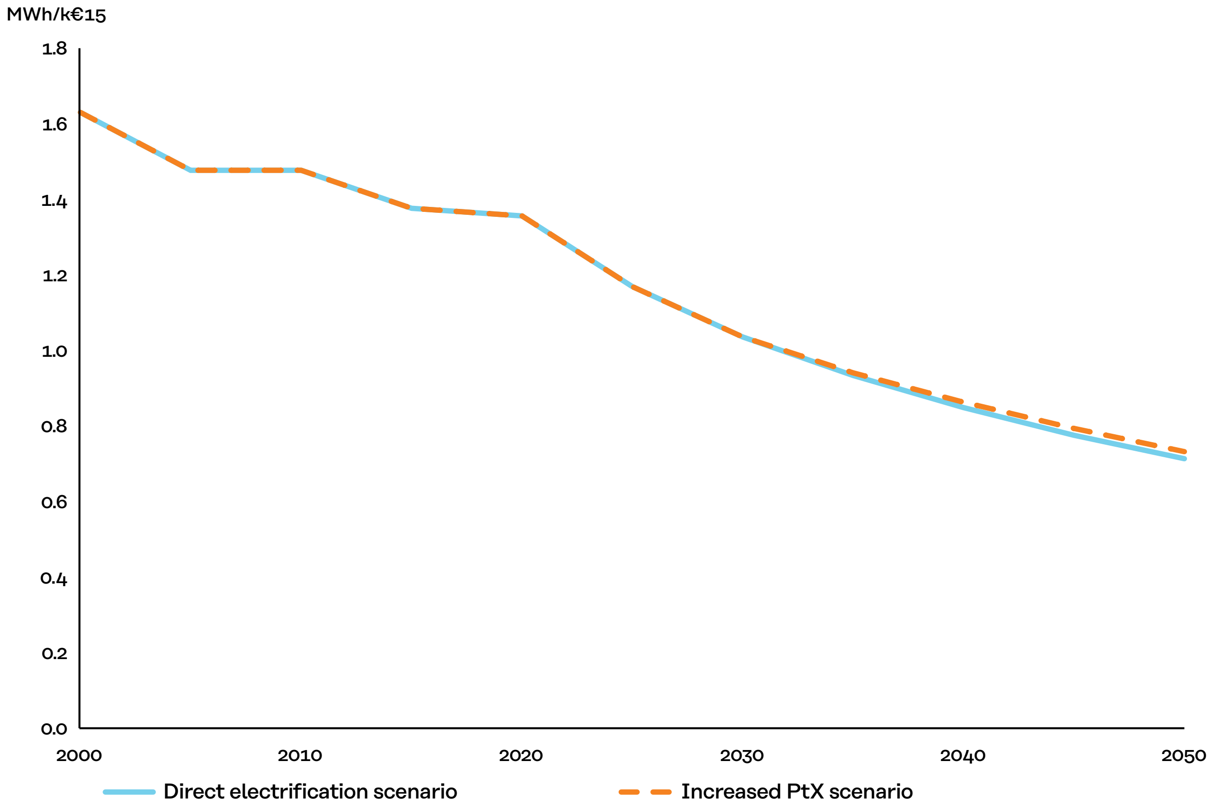
Key takeaways

- The two scenarios feature reasonable, but significant, energy efficiency improvements
- These improvements are based on two main effects:
  - Pure energy efficiency gains (renovation, improved equipment efficiency, etc.)
  - Switch towards more efficient end-use equipment, especially heat pumps and EVs

The achievement of the new emission targets relies on energy efficiency improvements in both scenarios. However, these are not expected to incur any drastic changes in terms of the lifestyle of the Finnish citizens and the possible impacts on the economy, as the decreasing final energy intensity of GDP shows in the Figure 16 (1.6 $MWh/k€_{15}$ to 0.7 $MWh/k€_{15}$). Final energy intensity of GDP describes how much final energy is related to the creation of one unit of GDP, here expressed in megawatt hours per thousand euros (real values).

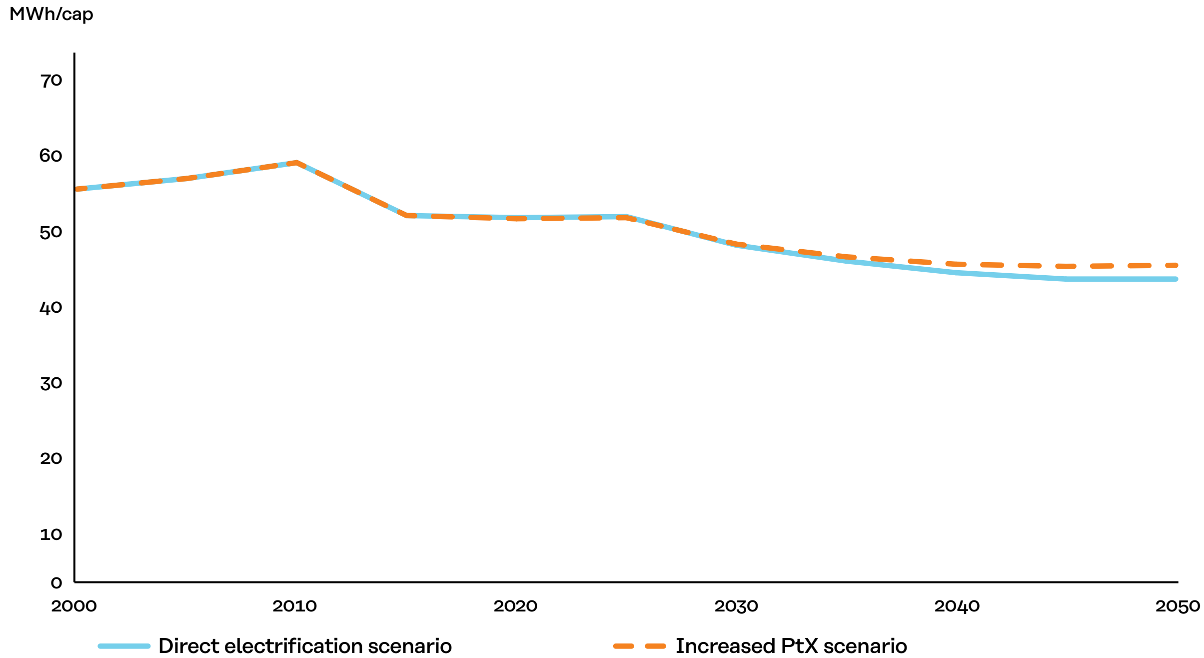
1 BECCS is projected to become significant in Finland only after 2040, since the Finnish 2035 emission target can be reached without requiring this technology, with cheaper solutions. BECCS is then required by 2050 to offset the last remaining GHG emissions to reach full decarbonisation, hence its development after 2040.
2 Due to modelling constraints, a strict carbon neutrality (net GHG emissions of 0 $MtCO_2eq$) was not technically achieved in 2035, however the trajectory is very close to this target. Net emissions in 2036 reach almost 2 $MtCO_2e$.

Figure 16: Final energy intensity of GDP, Direct Electrification & Increased PtX Scenarios



Notes: MWh/k€15 stands for MWh per thousand euros of GDP (in real 2015 terms).
Source: POLES-Enerdata model results by Enerdata

Figure 17: Final energy demand per capita, Direct Electrification & Increased PtX scenarios



Source: POLES-Enerdata model results by Enerdata

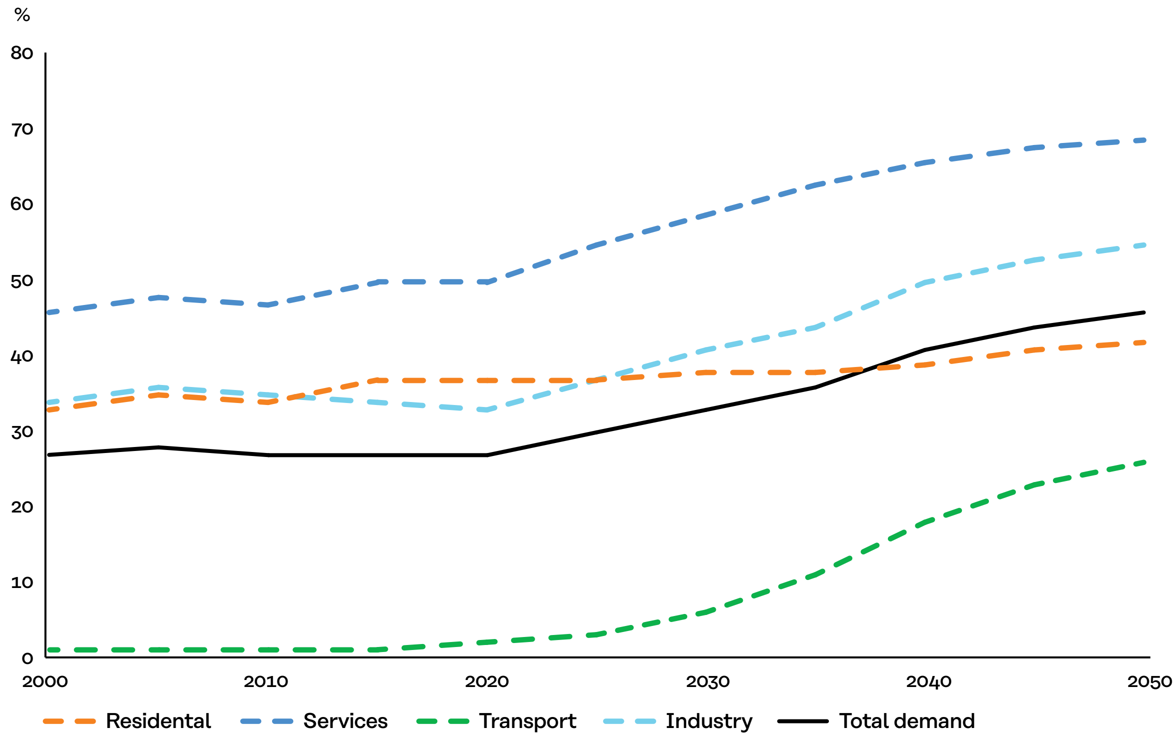
Under both scenarios, the long-term trajectory is slightly more ambitious than observed in the historical trends. The energy intensity of GDP would decrease by 1.9% per year on average over 2015-2050, around twice the 2000-2015 average. This decrease would result from a higher efficiency of final energy consumption, attributable to both efficiency gains (renovation, equipment efficiency, etc.) and a switch towards more efficient electricity-based technologies (e.g., heat pumps & EVs).

The decrease of final energy consumption from 287 TWh in 2015 to 251 TWh in 2050 (13%, Direct Electrification Scenario) and to 259 TWh (10%, increased PtX scenario) leads final energy consumption per capita to also remain on a slightly decreasing trend in the long run, as shown in Figure 17.

As mentioned above, demand-side energy efficiency gains would be achieved through a progressive shift towards electricity-based technologies. In Figure 18, the electrification rates are provided at sectoral level for the Direct Electrification Scenario. The share of direct electricity in final energy demand would increase from 27% to 46% between 2015 and 2050. Electric heating would progress, and heat pumps expand in the building and industry sectors, hence substantially improving the average efficiency of electricity usage. In the transport sector, the penetration of EVs would enable electricity to account for 26% of total energy consumption of the sector in 2050, compared to 1% in 2015.

Overall, the two scenarios assume significant, but realistic energy efficiency improvements, not expected to constitute a particular burden for the Finnish economy and citizens.

Figure 18: Share of electricity in final energy demand, total & by sector, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

3.3. Overall energy demand: Fossil fuels are replaced by renewables without unduly expanding biomass usage

Key takeaways

- Fossil fuels will completely disappear from the primary energy mix by 2050 and are mostly replaced by renewables, notably wind energy.
- Full decarbonisation of the final energy consumption by 2050 will be based on:
  - Wide-spread electrification of end-uses (electricity accounts for almost half of the final demand by 2050)
  - Stable biomass & district heating usage compared to historical levels
  - Development of Power-to-X fuels after 2030 to decarbonise hard-to-electrify sectors

In the context of a cost-efficient decarbonation of the Finnish energy system, the primary energy mix of the country, as displayed in Figure 19, will significantly change over the next decades. The historically high share of fossil fuels (46% in 2015) will decrease to zero by 2050, replaced by the development of renewable electricity in the form of wind, and solar to a lesser extent. Total primary energy from renewable electricity amounts to 139 TWh in 2050, i.e. 50% of the total (despite being accounted with a higher efficiency than the rest[3]). In the medium term, nuclear energy will play a role in the decarbonisation of the mix, peaking at 99 TWh in 2025 (26%) with the commissioning of Olkiluoto 3, but will eventually start to diminish again after 2030, to around 31 TWh or 11% in 2050. The use of bioenergy remains significant across the whole period and accounts for 39% of the total in 2050.

Finland's final energy consumption would also be subject to profound changes in the upcoming 30 years, as Figure 20 illustrates. In short, the demand for conventional fossil fuels (coal, natural gas, and oil products) would be progressively replaced by vectors supporting the decarbonation effort such as electricity to a large extent, but also bioenergy and Power-to-X fuels[4].

Final energy consumption[5] is roughly stable between 2015 and 2025 at 290 TWh, and would then decrease to 251 TWh by 2050. In this decrease, electrification would be the main cost-efficient decarbonation driver in the different end-use sectors: the 2015 27% market share of electricity in total final consumption significantly grows to reach 36% in 2035 and 46% in 2050. At that time, electricity would be the main energy vector for final consumption, followed by bioenergy (30% of total final energy consumption vs 25% in 2015), district heating uses (14% in 2050, globally stable over the period) and Power-to-X (11% in 2050). Consumption of PtX fuels (hydrogen and synthetic fuels) would start in 2030 with 3 TWh, to progressively develop and reach 28 TWh by 2050.

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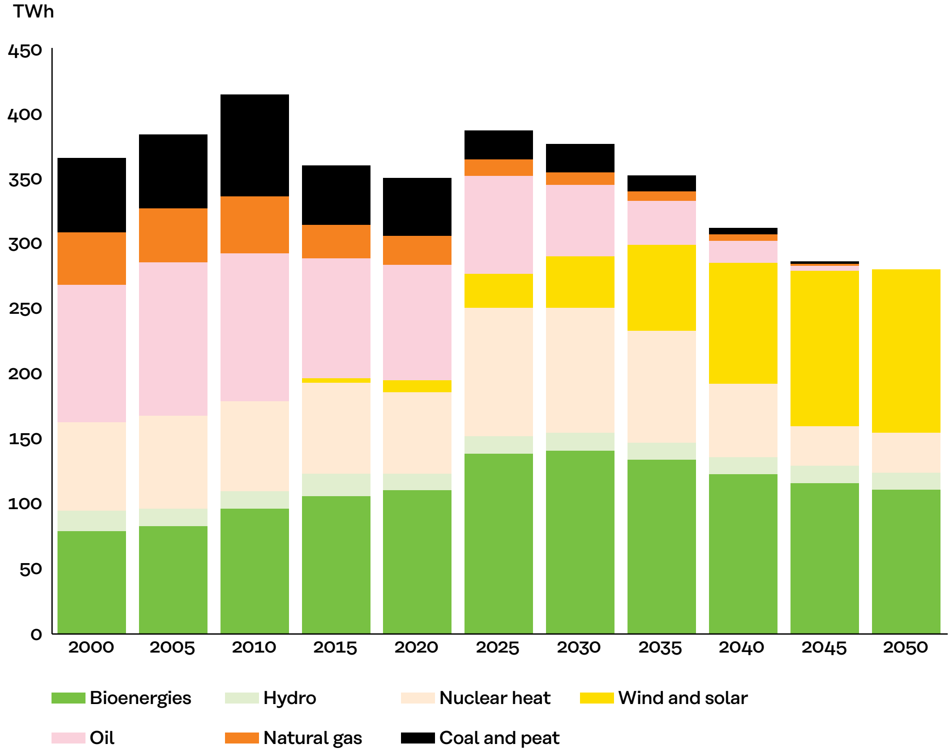
3 In line with energy accounting conventions, primary electricity from wind, solar & hydro is accounted for with an efficiency of 100% in the energy mix, while for nuclear an efficiency of 33% is assumed (the nuclear heat is assumed to be the primary fuel), and for thermal energies average end-use efficiencies are considered.

4 Power-to-X fuels refer to hydrogen produced from electrolysis, and products derived from such hydrogen, including synthetic hydrocarbons and chemicals (ammonia, etc.).

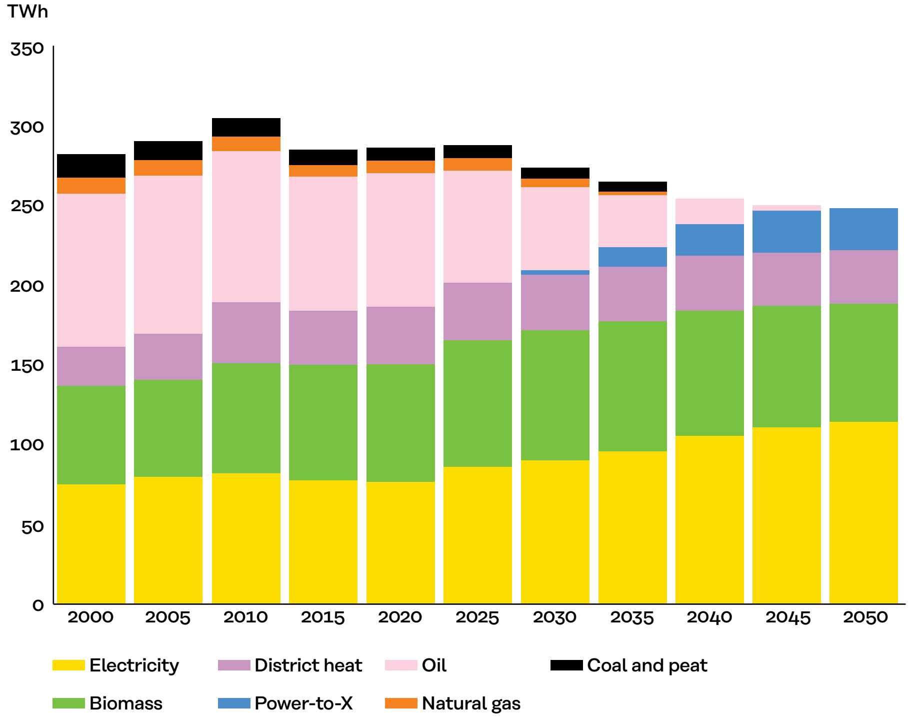
5 Final energy demand includes energy products consumed for both energetic and non-energetic uses.

Figure 19: Primary energy consumption by energy source, Direct Electrification Scenario[1]



Source: POLES-Enerdata model results by Enerdata

Figure 20: Final energy consumption by energy carrier, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

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1 The Figure 19 excludes electricity trade. The increase in primary consumption in 2025 would be due to the additional nuclear fuel required to run Olkiluoto 3, which would also lead to significantly lower electricity imports.

3.4 Electricity demand: Decarbonisation will drive electricity demand growth – almost doubling in 2050 vs. 2015; biomass & PtX play a smaller but important role

Key takeaways

- Electricity demand will double by 2050, driven by electrification of final end-uses and electrolysis for hydrogen production.
- Power-to-X fuels will develop significantly after 2030, enabling the full decarbonisation of heavy transport, some industrial processes and chemical feedstocks.
- Bioenergy will also play a substantial role in the decarbonisation, with increased consumption in the medium-term again returning to historical levels by 2050

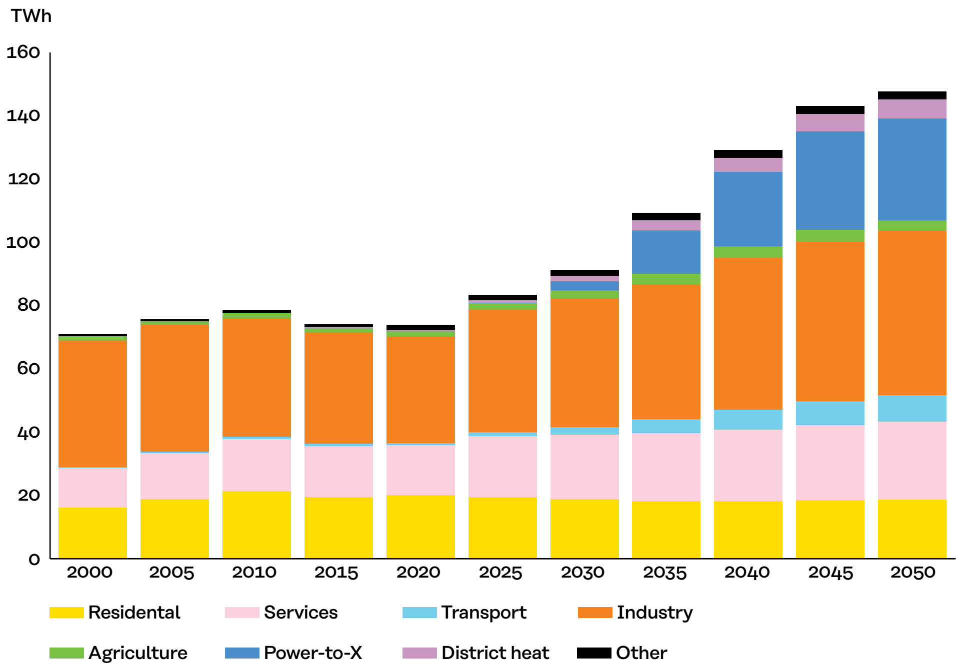
The carbon-free energy system envisioned in both scenarios relies on decarbonised energy carriers, most notably electricity, whose demand doubles by 2050, but also power-to-X and bioenergy. This sub-section focuses on the respective roles of these vectors.

3.4.1 Electricity demand by sector

Electricity is envisioned as the main energy carrier enabling the full decarbonisation of the Finnish economy, through direct electrification of the final sectors (see above), as well as indirect uses in the form of Power-to-X fuels.

The electricity demand, see Figure 21, is therefore projected to grow over the next three decades, reaching 159 TWh by 2050 in the Direct Electrification Scenario, i.e. double its 2015 level. The development of

Figure 21: Electricity demand by sector, Direct Electrification Scenario[1]



Source: POLES-Enerdata model results by Enerdata

1 Electricity demand presented on the Figure 21 & Figure 22 excludes power plant self-consumptions and transmission and distribution losses.

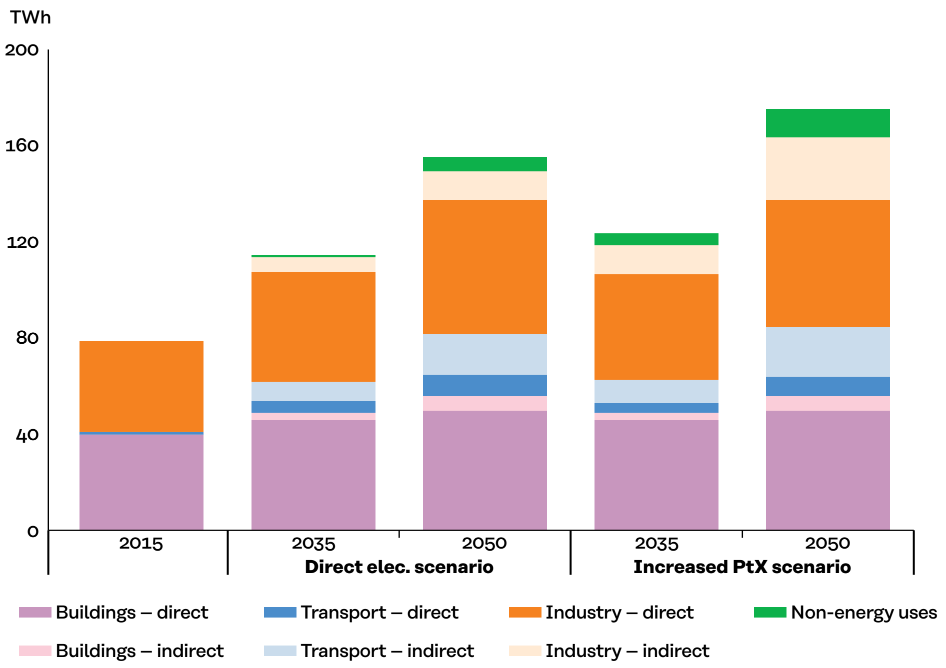
Power-to-X fuels production, mostly after 2030, is responsible for almost half of this increase with +35 TWh over 2015-2050. Direct electrification of final end-uses would also contribute to the electricity demand growth, with absolute increases of 18 TWh in industry, 8 TWh in transport and 8 TWh in buildings. District heating would also contribute to the trend, with a growing role for electricity in the heat supply, in the form of heat pumps (6 TWh in 2050).

In the Increased Power-to-X Scenario production of Power-to-X fuels absorbs almost 60 TWh by 2050, leading the total electricity demand to reach around 180 TWh. Compared to the Direct Electrification Scenario, this increased Power-to-X demand offsets direct electricity consumption, therefore the increase in direct electricity uses is slightly lower in this scenario with 13 TWh in industry, 7 TWh in transport & 6 TWh in buildings.

Looking at the total electricity consumption allocated by end-use sector in Figure 22, including direct and indirect uses, it is evident that industry (energy uses) and transport will contribute the most to the electricity demand growth, with respective increases of 30 TWh and 26 TWh over 2015-2050 in the Direct Electrification Scenario, followed by buildings (+16 TWh) and non-energy uses (mostly chemical feedstocks, +6 TWh).

In the Increased Power-to-X scenario, industry & non-energy uses absorb even more electricity, with additional increases of 11 TWh and 12 TWh between 2015 and 2050 compared to the Direct Electrification scenario.

Figure 22: Electricity demand by final use (direct & indirect), Direct Electrification & Increased PtX Scenarios



Source: POLES-Enerdata model results by Enerdata

3.4.2 Power-to-X usage

Power-to-X will help to decarbonise hard-to-abate sectors, such as heavy transport, some industrial uses and chemical feedstocks, either in the form of synthetic fuels (diesel, kerosine), other chemicals (methanol, ammonia), or simply hydrogen. Power-to-X fuels, and especially synthetic fuels, enable to continue using the existing equipment (e.g. ICE type vehicles) and infrastructure (transport and distribution networks).

In the Direct Electrification Scenario shown in panel (A) of Figure 23, Power-to-X consumption would progress to 28 TWh by 2050, representing 11% of the total final energy consumption. The figure shows that half of the Power-to-X fuels would be consumed in transport with 14 TWh, mostly using synthetic fuels (10 TWh) but some hydrogen (4 TWh) is present. They prove especially competitive in the heavy freight transport segment where direct electrification is more difficult than in the passenger car fleet. Their trend would decrease after 2045, due to the continued penetration of EVs and hydrogen vehicles, reducing the remaining ICE vehicle share. Industry also becomes a significant Power-to-X consumer with 9 TWh in 2050, of which notably 4 TWh of hydrogen absorbed by the steel industry. Power-to-X fuels, mostly in the form of hydrogen, also enable to reach full decarbonisation of the non-energy uses sector, which absorbs 5 TWh of these by 2050.

Panel (B) of Figure 23 shows consumption of Power-to-X fuels in the Increased Power-to-X Scenario, increasing to 47 TWh by 2050, representing 19% of the total final energy consumption. The increase in PTXS shown is mainly driven by industrial consumption (+11 TWh between the two scenarios), non-energy uses (+4 TWh) and transport (+3 TWh), offsetting direct electrification and bioenergy use.

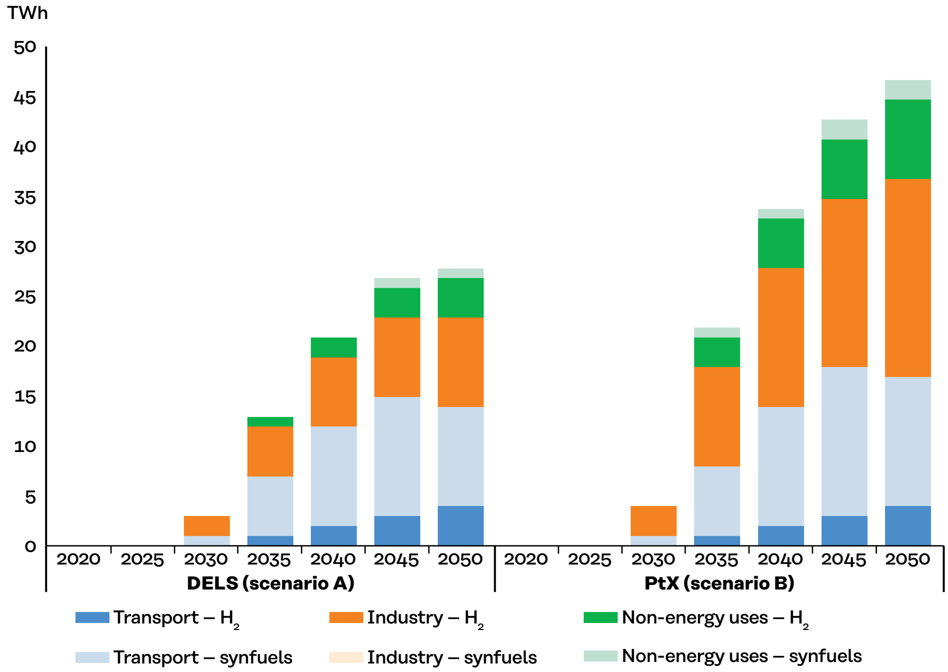
The production of these PtX fuels requires 34 TWh (DELS) and 60 TWh (PTXS) of electricity generation, as shown in panel (B) of Figure 24. Panel (A) of Figure 24 further shows the split by PtX fuels, namely hydrogen and synthetic fuels, where their proportional shares are approximately similar between the two scenarios, but in absolute terms much higher in the PTXS scenario.

3.4.3 Biomass usage

Bioenergy also plays a very significant role in the decarbonisation of the Finnish energy system, with various types of biomass utilised in energy generation and as feedstock: wood, black liquor, other industry by-products, liquid biofuels, biogas, biochar, algae oil.

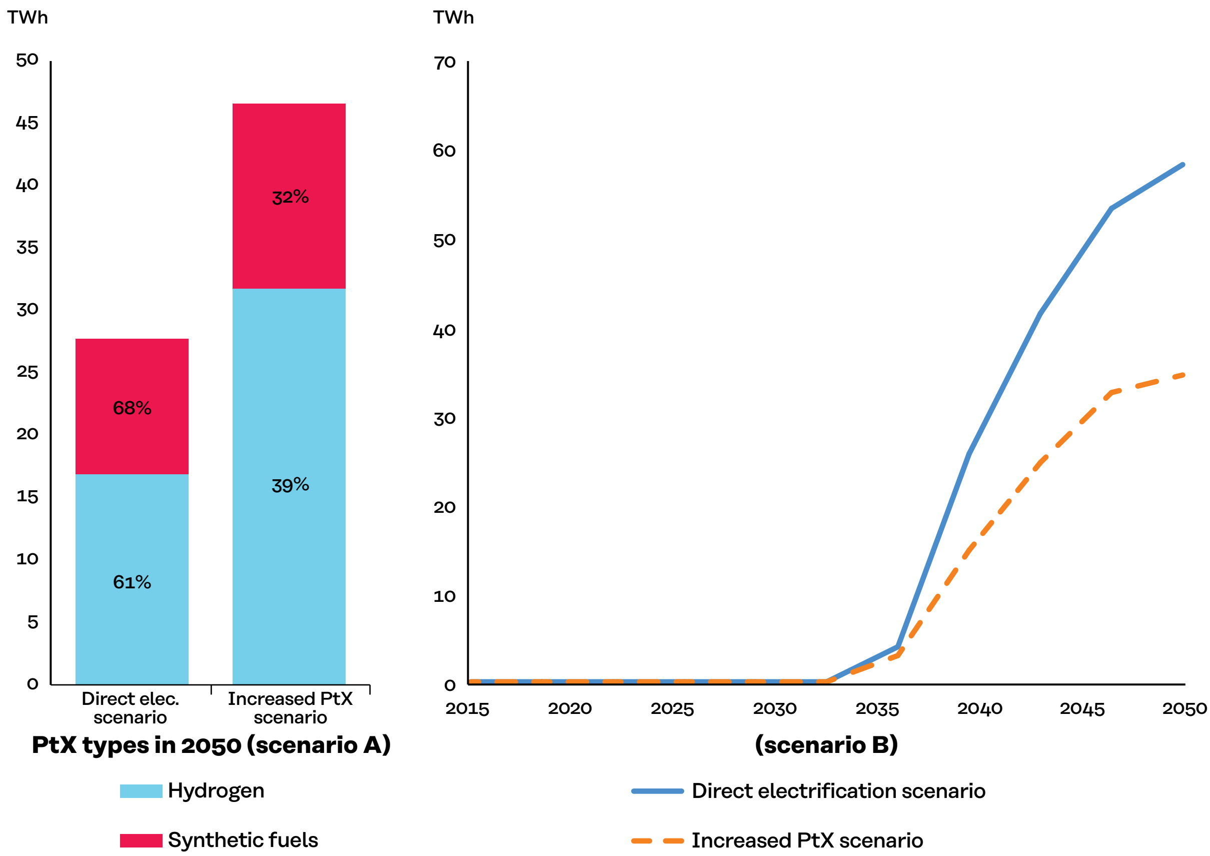
Figure 25 presents a breakdown of historical bioenergy consumption by source in 2018 (Tilastokeskus, 2021) and estimates for 2050 in each scenario. The 2050 breakdown estimates assume, for example, that the solid wood-based bioenergy would be mostly utilised as heat in buildings and services sector, either in own boilers or in district heating. Biochar, which is used in ferrochrome steel to replace coal, is here assumed to be a solid wood-based fuel as well. The majority of energetic bioenergy use in industry is assumed to be from waste liquids (black liquor). The current consumption of bioenergy in industry (the majority consumed as black liquor in the forest industry) is assumed also for the future. The transport sector's biofuel use is assumed to be mostly liquid biofuels, especially in heavy trucks segment, which is harder to directly electrify. Biogas is used mainly in transport sector, power sector, and industry sector to supplement other fuels.

Figure 23: Final consumption of Power-to-X fuels, Direct Electrification Scenario (A) and Increased PtX Scenario (B)



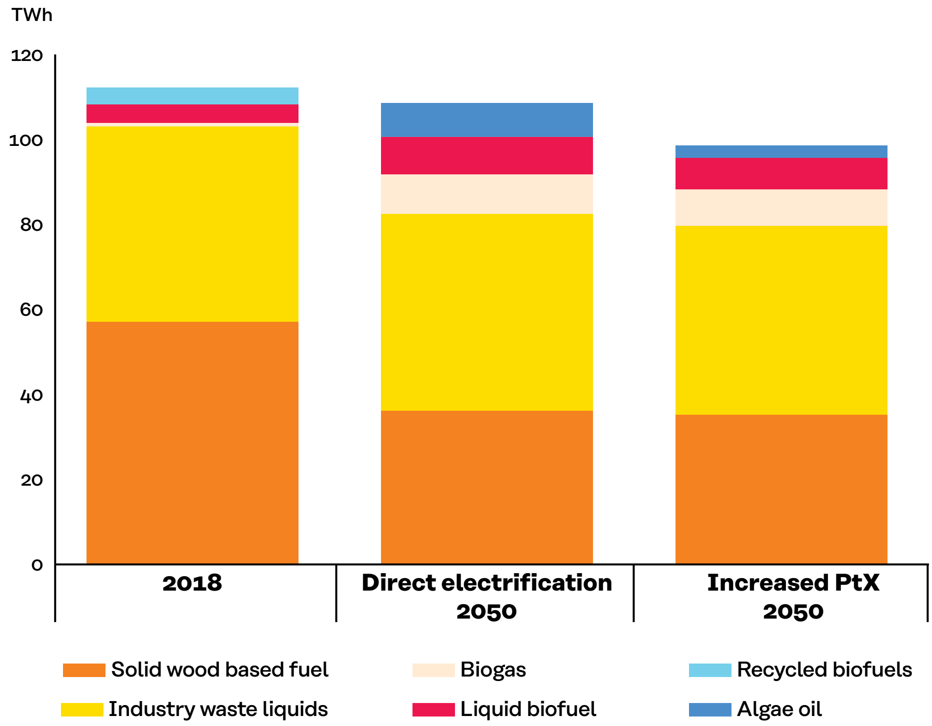
Source: POLES-Enerdata model results by Enerdata

Figure 24: Split of Power-to-X fuels by type (A) & Electricity consumption for Power-to-X production (B), Direct Electrification & Increased PtX Scenarios



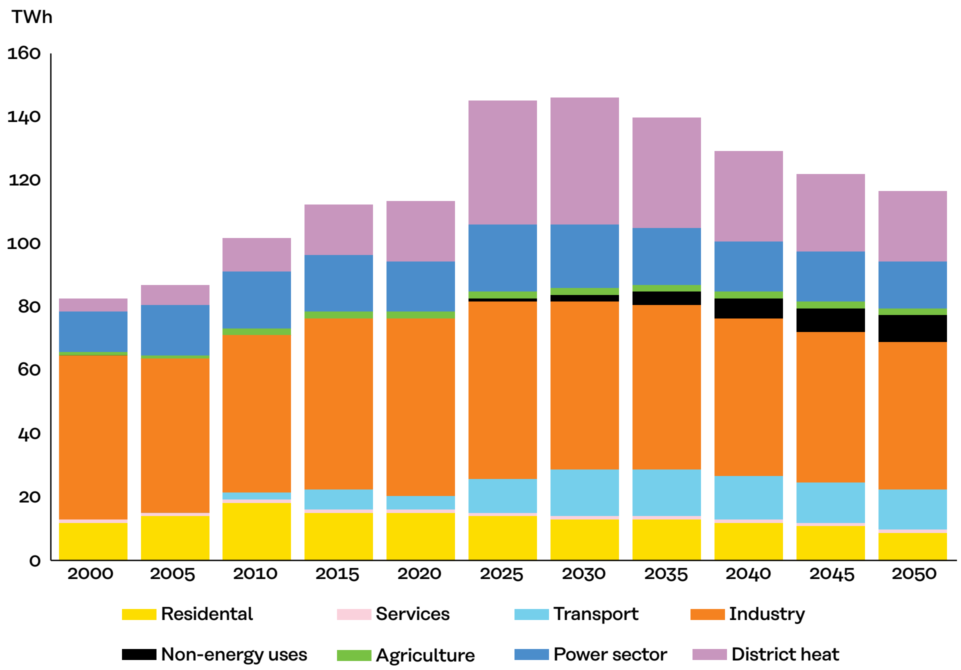
Notes: Values in panel (A) refer to the year 2050.
Source: POLES-Enerdata model results by Enerdata

Figure 25: Breakdown of bioenergy consumption by source, 2018 historical value and 2050 estimate in Direct Electrification & Increased PtX Scenarios



Source: Historical values: Statistics Finland; Scenario results: LUT analysis.

Figure 26: Total bioenergy consumption by sector, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

In both scenarios, the total bioenergy consumption[6] would increase in the medium term due to a higher demand in the district heating sector reaching almost 140 TWh in 2030, before decreasing back to historical levels (Figure 26). It would reach 109 TWh in 2050 in the Direct Electrification Scenario, close to the 2015-2019 average of 110 TWh. If necessary, the non-wood-based bioenergy and imports could also be utilised to avoid the shrinking of the LULUCF carbon sink.

Bioenergy use in the transport sector, including both liquid biofuels and biogas, increases to reach 14 TWh by 2030, then stabilising to 12 TWh in 2050, limited by the large uptake of electromobility. In the transport sector, bioenergy has a large role in decarbonising especially heavy transport, such as trucks. Residential bioenergy consumption decreases, from 15 TWh historically to 9 TWh in 2050, offset by the surging electrification of heating systems. The use of bioenergy in the industry and in the power sector would also decrease slightly .

In the Increased Power-to-X Scenario, bioenergy demand in the transport and industry sectors is slightly lower (2 TWh less in each sector in 2050), while non-energy uses feature the highest discrepancy with 3 TWh compared to 8 TWh in the Direct Electrification Scenario.

3.5 Industry sector: Broad electrification will be supported by pockets of PtX-usage

Key takeaways

- Electricity will offset most of the historical fossil fuel consumption, and account for half of the industry energy use demand by 2050
- Power-to-X fuels will also contribute, enabling the decarbonisation of hard-to-electrify processes
- Non-energy uses, notably chemical feedstocks, are decarbonised using bioenergy (e.g. algae oil) and power-to-X fuels, as well as increased recycling.

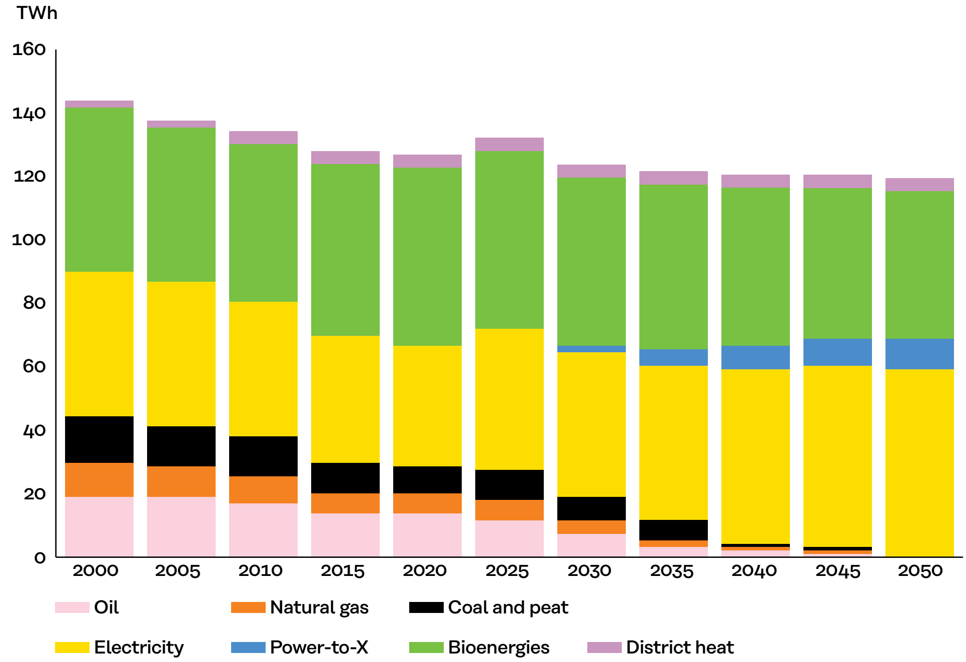
This sub-section presents the results of the study relative to the industrial sector, and the potential bottlenecks, enablers and recommendations for the decarbonisation of the Finnish industry.

3.5.1 Industry full-energy balances

The decarbonisation of the industry energy uses will rely mostly on direct electrification, such as converting oil boilers into industrial heat pumps or coal-fired furnaces into electric arc furnaces. Power-to-X fuels will play an important role in hard-to-electrify processes, such as steel reduction and manufacturing of chemical products.

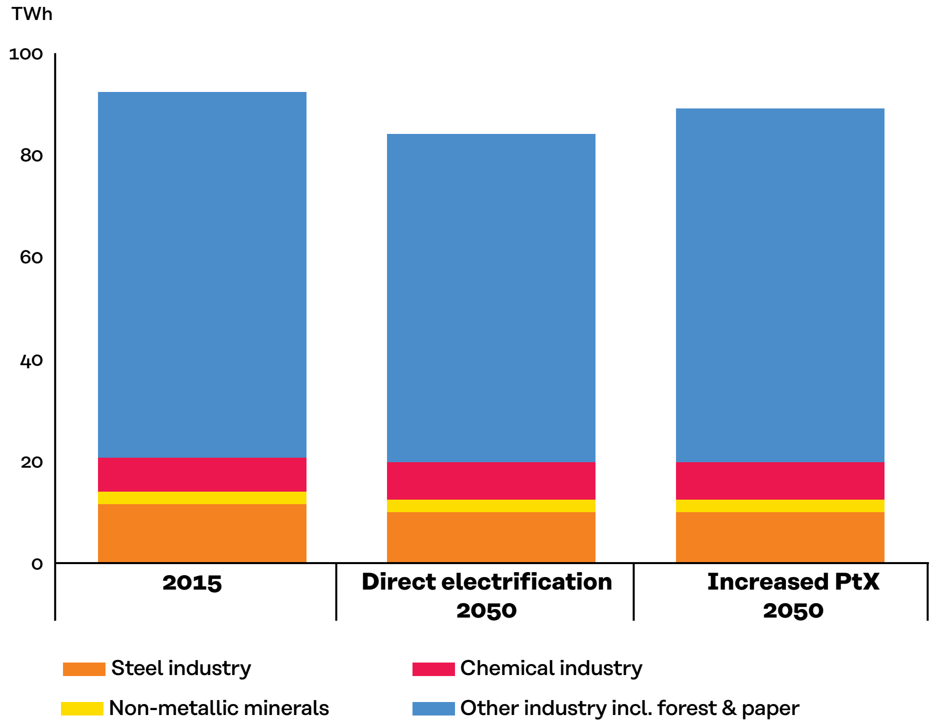
6 Use of biomass as materials is excluded, only energy use is accounted for here.

Figure 27: Final energy consumption of industry by energy carrier, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

Figure 28: Final energy consumption of industry by subsector, 2015 & 2050 in the Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

The **Direct Electrification Scenario** shown in Figure 27, depicts a slight decrease in industrial energy consumption[7] (0.25% per year over 2015-2050), despite positive economic growth assumptions[8], thanks to energy efficiency gains and switch to more efficient solutions, especially electrification. Industrial energy consumption will reach 112 TWh in 2050 from 122 TWh by 2015.

Electricity would develop quickly to replace fossil fuel consumption. It will account for 56 TWh by 2050, i.e. 50% of the total, from 40 TWh i.e. 31% in 2015. Bioenergy use decreases from 58 TWh (42%) in 2019 to 44 TWh (39%) by 2050, leaving a higher share of the domestic biomass production potential for other sectors, especially district heating. Around two-thirds of this bioenergy consumption is associated with CCS by 2050, therefore enabling to create negative net emissions as described in section 3.1. Power-to-X fuel consumption increases from 2030 onwards, reaching 9 TWh in 2050.

In the Increased Power-to-X Scenario industrial energy consumption is slightly higher than in the Direct Electrification Scenario, reaching 119 TWh by 2050. This is explained by the lower average end-use efficiency, with a higher Power-to-X market share (17% in 2050, i.e. 20 TWh).

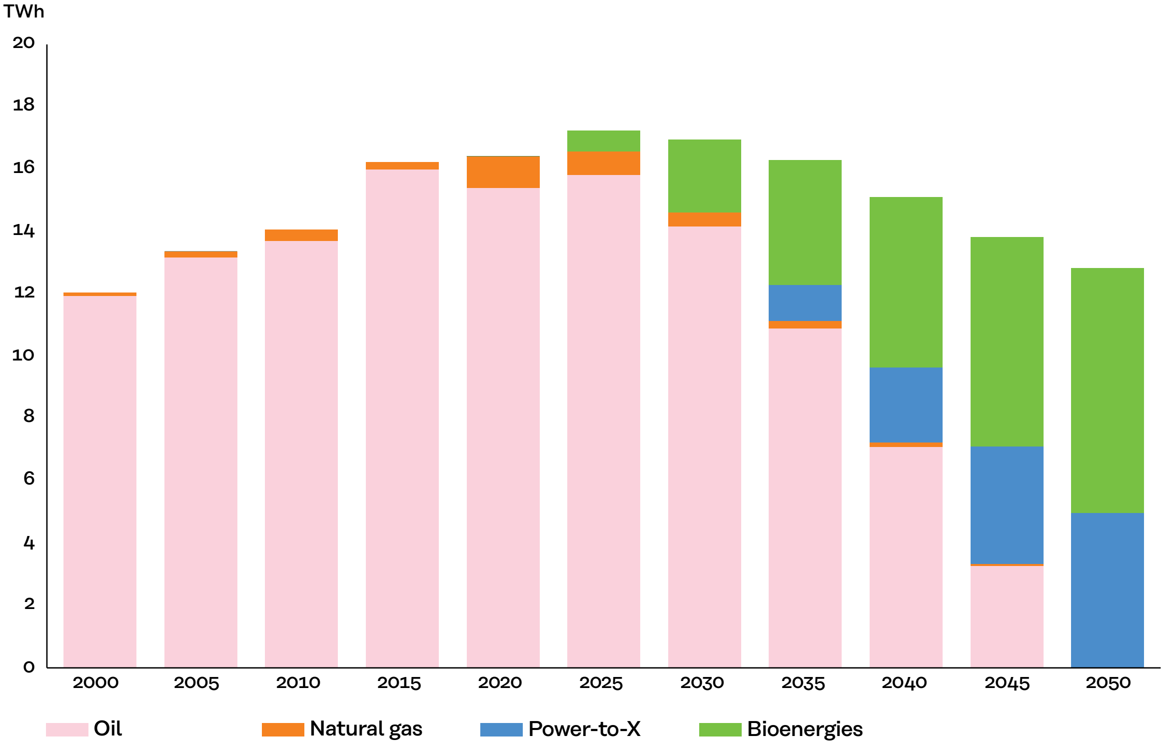
The share of each industrial subsector represented in the model in the industrial energy consumption does not evolve much compared to the historical levels, as shown in Figure 28. By 2050 in the DELS, Steel industry accounts for 12% of the total industry energy use (stable since 2015), Non-metallic minerals for 3% (stable since 2015), Chemical industry for 9% (+2 percentage points since 2015) and Other industry (including notably forest, pulp & paper industries) for 76% (-2 percentage points since 2015).

The Steel industry segment is fully decarbonised by 2050, with the deployment of electric arc furnaces and switch of the reduction agent from coal largely to hydrogen (direct reduction), and to biochar to a lesser extent. Steelmaking will absorb around 4 TWh of hydrogen by 2050 in the DELS. The paper & forest industry remains largely fueled by bioenergy up to 2050, although its share decreases with some electrification there as well, leaving a larger share of domestic bioenergy resources for other sectors. Chemical and non-metallic minerals sub-sectors are decarbonised mostly through direct electrification, completed by a moderate use of bioenergy and PtX. Electricity respectively represents 71% and 47% of their energy consumption mix by 2050.

The consumption of energy products for non-energy uses, for instance oil as chemical feedstock, will be completely transformed by 2050. The increasing recycling of products will enable a decrease in feedstock consumption to 13 TWh by 2050 from 16 TWh in 2015 within both scenarios (see Figure 29 for DELS), and the historically 100% fossil-based mix will progressively shift towards bioenergy and Power-to-X fuels.

7 Industrial energy consumption excludes non-energy uses, accounted for separately. Also, the fuels used to produce industrial steam are accounted for here, not the steam itself (including sold steam).
8 Economic growth assumptions are presented in Appendix A.5.

Figure 29: Final consumption for non-energy uses, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

Under the **Direct Electrification Scenario,** see Figure 29, bioenergy would represent 61% of the fuels consumed by 2050, with the remaining 39% from Power-to-X fuels, the majority in the form of hydrogen. Based on the chemical industry's new roadmap (Pöyry, 2020a), a major new potential source of bioenergy could be algae oil. Different recycled materials and fuels also play a key role by reducing the required fuel consumption, such as different vegetable oils, fats, plastics, and other wastes in many different forms.

In the Increased Power-to-X Scenario the uptake of Power-to-X fuels for non-energy uses is even higher (75% in 2050), enabling a lower use of bioenergy in this sector. Role of recycled materials is assumed to stay mostly similar as in the Direct Electrification Scenario.

3.5.2 Key bottlenecks and enablers in industry

Finnish industry operates in a global market, meaning that EU-level actions, industrial policies and regulations are of critical importance. Large investments are needed to electrify process heat in the industrial sector and the EU Emission Trading System (EU ETS) incentivises fuel switching in the short-term and promotes low-carbon investment in the long-term. However, carbon emission pricing is tightly related to competition policy and industry competitiveness because different carbon costs across jurisdictions may lead to carbon leakage, i.e. shift in economic activity and/or change in investment structure from high to low carbon-cost jurisdictions. Therefore, a level-playing field in the EU has to be maintained via compensation schemes for some electro-intensive industries (according to the State Aid rules) and the recently discussed carbon border adjustment mechanism (CBAM). Finnish industrial global competitiveness will be supported when adequate carbon-leakage mechanisms are systematically implemented on the EU-level.

Another EU-level limitation impacting Finnish industry is the lack of incentive for the use of carbon neutral (recycled) feedstock, biomass, or synthetic hydrocarbons in such industries as chemicals and plastics. One of the reasons for the lack of demand is that industries do not have to pay for the embodied emissions in their products. However, the global demand for carbon neutral products is increasing and Finnish industry could benefit from first-mover's advantages if it manage to meet this demand. There is a need to explore whether current EU or national incentives suffice for the transition to carbon neutral production or whether additional incentives or policies are needed.

Some process emissions, as well as land use emissions are hard to reduce to zero. Bioenergy with carbon capture and storage (BECCS) would be needed to compensate them. Bioenergy-based forest industry could provide this compensation, as bioenergy is already considered net neutral. Currently, however, there are no incentives for industry to produce negative emissions. Establishing respective incentives at national or EU-level is therefore essential.

Industry electrification might also be slowed down by long investment horizons in certain industrial segments (notably the steel and chemical industry) and reinvestment cycles beginning before decarbonised technologies achieve competitiveness against traditional fossil-based solutions. To avoid long-term fossil lock-ins, short to medium-term incentives – potentially going beyond the EU ETS – might be required. A clear national roadmap for decarbonisation together with the requirement for companies to draw-up individual carbon neutrality roadmaps could support the identification and subsequent mitigation of looming fossil lock-ins. This should be supported by the continued assessment of major re-investment cycles and respective decarbonisation incentives.

At national level, Finland currently does not have a clear national hydrogen strategy, even though hydrogen is receiving attention in the new Energy and Climate Strategy. But the lack of clear strategy could make hydrogen related investments riskier or even prevent them. A clear strategy for the national hydrogen infrastructure – and its potential connection to the European hydrogen infrastructure – might also act as an enabler for wide scale adoption of hydrogen in industry and other sectors. Investment needs for this infrastructure must be mapped out and potential funding sources should be explored. Planning and building process should be initiated as soon as possible.

A clear regulatory framework for hydrogen and its transmission – aligned at EU-level – could foster hydrogen uptake in Finland. Potential regulatory challenges include production classification and certification, subsidy schemes to support the build-up of the hydrogen industry as well as the taxation of hydrogen with the aim of avoiding double taxation of electricity and the produced hydrogen.

Full electrification is currently not possible for all industrial processes. Biomass is an alternative or complement in several applications, e.g. ferrochrome processes in the metal industry, or in the cement industry. These applications could significantly increase the demand for biomass leading to challenges with the sustainable availability of biomass. Two potential mitigation pathways consist of 1. strengthening of circular economy approaches, and 2. replacing burning of biomass, where possible, with industrial heat pumps (e.g. forest industry produces a high share of process heat from biomass-based by-products, mostly from black liquor (Tilastokeskus, 2020).

Next steps recommendations for industry sector

- Explore the implementation of needed incentives for carbon neutral processes and feedstock on the national and EU-level.
- Explore national and European schemes for incentivising negative emissions and establish a respective market.
- Develop a clear national hydrogen strategy.
- Develop a broad EU-level regulatory framework supporting the build-up of a hydrogen industry in Finland, including infrastructure.
- Ensure a favourable and competitive investment environment for industrial actors aiming for decarbonising investments – including fast permitting and predictable regulation
- Continuously assess re-investment cycles of major fossil energy users and incentives to switch to decarbonised technologies to avoid long-term lock-ins
- Promote industrial companies to develop carbon neutral roadmaps to help develop clear view of needed actions to decarbonise their operation and to enhance the discussion with stakeholders.

3.6. Transport sector: Decarbonisation will rely on longer-term electrification with biofuels and synfuels playing a significant role in heavy transport

Key takeaways

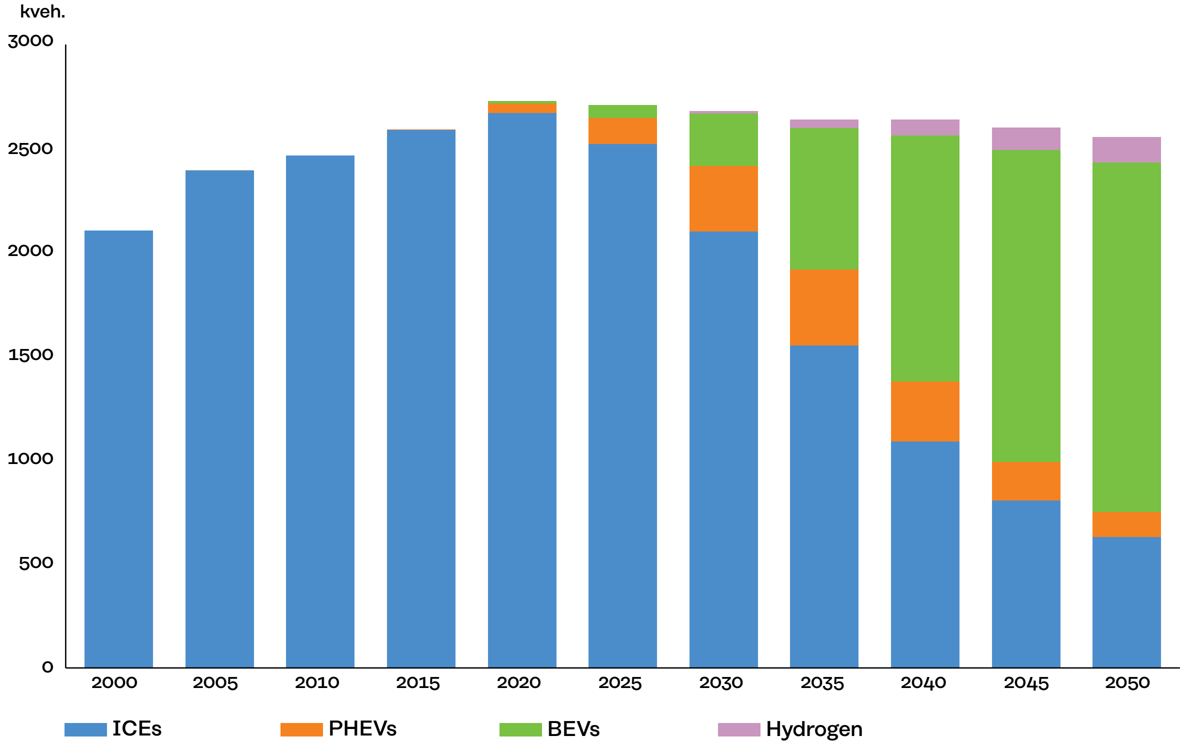
- Electromobility rapidly takes over in the light transport segments, representing more than two third of the passenger car fleet by 2050
- ICE vehicles fuelled by power-to-X fuels and biofuels remain more competitive in the heavy transport segment
- Switch towards more EVs, and improvements in vehicle efficiencies, lead the transport final energy consumption to significantly decrease by 2050

This sub-section presents the results of the study relative to the transportation sector, and the potential bottlenecks, enablers and recommendations for the decarbonisation of transport. International aviation and maritime transport are beyond the scope of the study, which only focuses on domestic transportation.

3.6.1 Transport full-energy balances

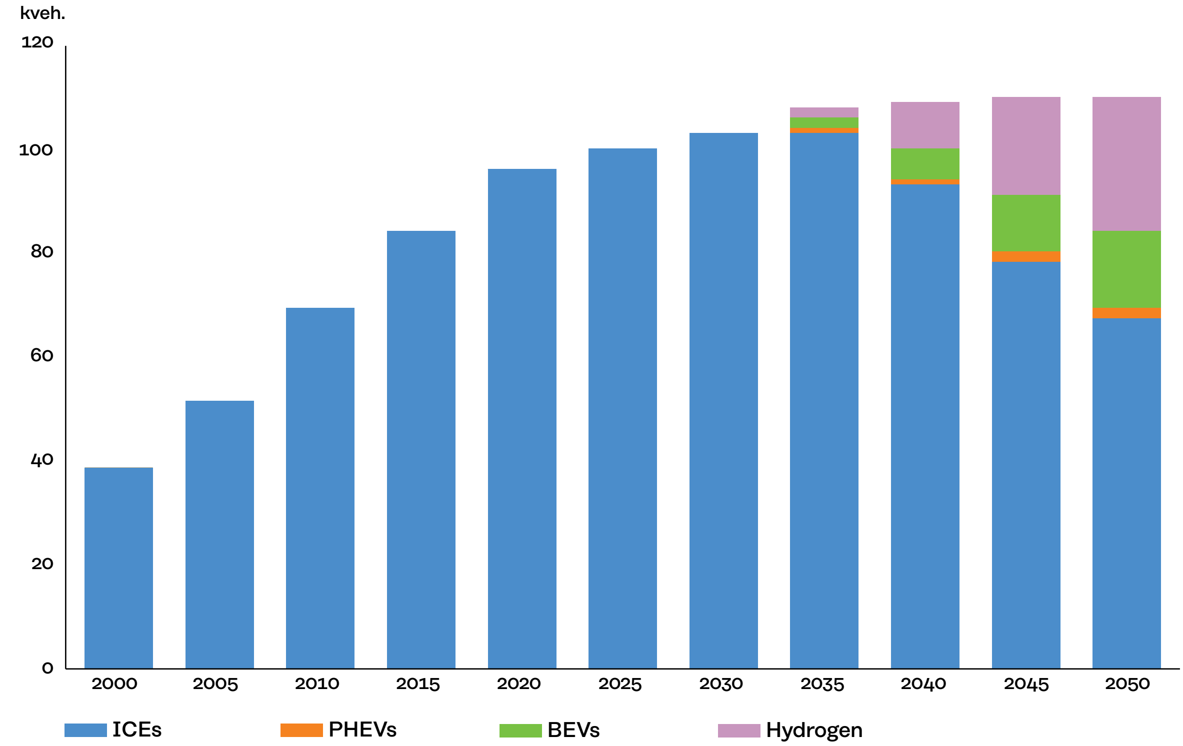
The decarbonisation of the transport sector is envisioned in both scenarios as relying heavily on direct electrification, especially for passenger transport. Power-to-X fuels and biofuels allow to decarbonise harder-to-electrify transport segments, such as heavy trucks transport.

Figure 30: Evolution of the passenger car fleet by technology, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

Figure 31: Evolution of the heavy truck fleet by technology, Direct Electrification Scenario



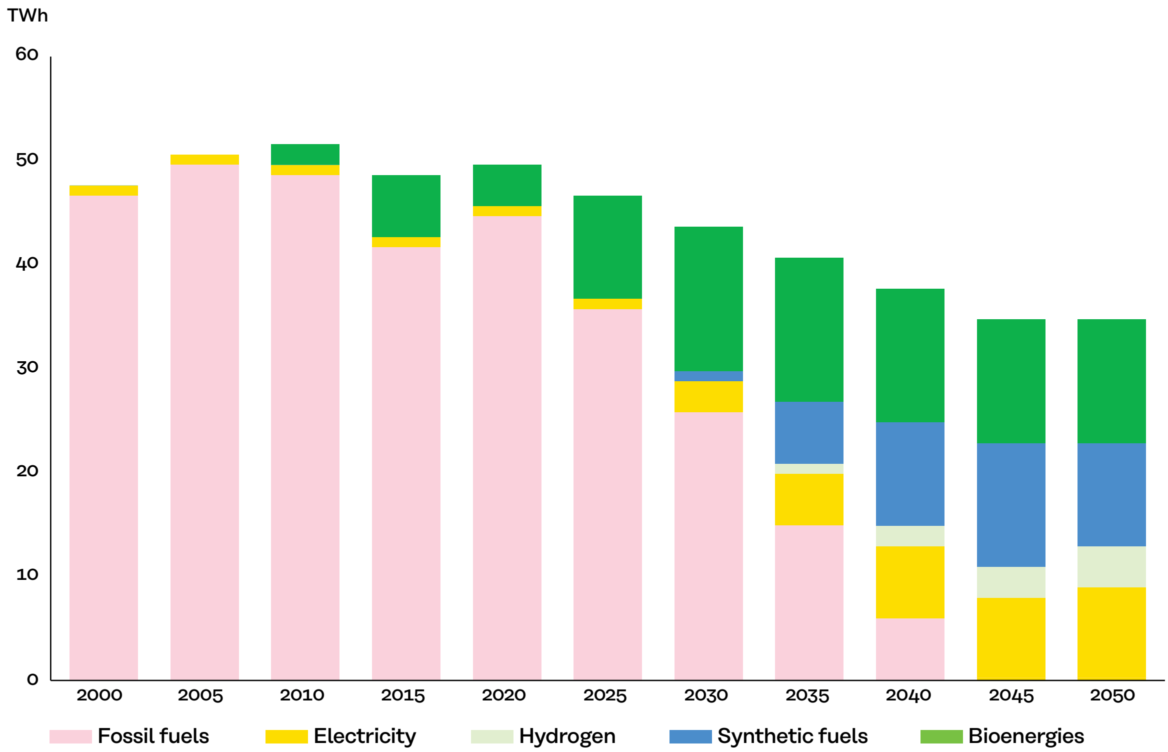
Source: POLES-Enerdata model results by Enerdata

In the **Direct Electrification scenario**, electromobility will progress rapidly in the passenger car segment, with 66% of the private vehicle fleet being fully electrified by 2050, see Figure 30. Hybrid vehicles appear as a medium-term solution, with their share peaking at 14% in 2035 and decreasing afterwards. The uptake of hydrogen fuel cell vehicles would be limited (5% in 2050), due to constraints on distribution infrastructure and unfavourable cost competitiveness compared to cheaper Battery Electric Vehicles (BEVs). Internal Combustion Engine (ICE) vehicles will still represent around 25% of the fleet in 2050, running on synthetic fuels, biogas, and other biofuels.

In other segments like heavy trucks (see Figure 31), electrification is far less competitive (10% of the fleet in 2050), limited by the investment costs in EVs and technical constraints on range. The use of biofuels and of Power-to-X fuels is seen as more competitive in this segment, especially synthetic fuels which largely allow for the reuse of existing infrastructures. Hydrogen trucks are also a credible solution in the long-term in some situations, making up 23% of the fleet in 2050.

The Direct **Electrification Scenario envisages** a decrease in transport energy consumption from 49 TWh in 2015 to 34 TWh (see Figure 32), driven down by the adoption of EVs and improvements in engine efficiencies. In terms of energy consumption, electricity would increase to 9 TWh by 2050, of which 5 TWh would be in the passenger car segment. Biofuels, including both biogas and liquid biofuels, will play an important role in the decarbonisation, especially in the medium term (peaking at 14 TWh in 2030-2035 from 6 TWh in 2015, and then decreasing to 11 TWh by 2050). Synthetic fuels, and to a lesser extent hydrogen, would account for the remaining demand of the sector and reach 14 TWh by 2050.

Figure 32: Final energy consumption of transport by energy carrier, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

Under the Increased Power-to-X scenario synthetic fuels consumption would be slightly higher and reaches 17 TWh in 2050, reducing electricity consumption by 1 TWh and bioenergy by 2 TWh in comparison to the Direct Electrification scenario.

3.6.2 Key bottlenecks and enablers in transport[9]

In order to reach carbon neutrality by 2035, changes in the transport sector must happen rapidly. By 2035 roughly 40% of the passenger vehicle fleet must comprise EVs (EV), either plug-in hybrids (PHEV) or battery EVs (BEV). This may be challenging, as the Finnish average age for cars is over 12 years (Traficom, 2021). This would require fast and considerable changes to new cars that are being sold, meaning thath nearly all of them should be EVs in the coming years. Challenges might result from the affordability of new EVs. Mitigation could include balanced tax, subsidy and/or loan measures for EVs and other low emission vehicles, as well as carbon neutral fuels. Similarly, taxes could be increased for high emission solutions or transportation sector might be made part of emission trading system. Inherent mitigation might result from decreasing EV prices and additional revenue from including EV charging in demand side response schemes.

Biofuels, either liquid fuels or biogas, are already produced in Finland and there is a blend-in mandate for them. Biofuels could enable some of the old cars, as well as other vehicles, to utilise carbon neutral fuels. The challenge comes from the availability of sustainable biomass to create the needed biogas or liquid fuels. The availability of new sources for biofuels should therefore be explored, such as the utilisation of waste.

Promising technologies include synthetic fuels created from Power-to-X (PtX) processes. These fuels could be manufactured domestically, could replace all used fossil fuels, and be utilised in the same engines as before. Synthetic fuels are facing a major challenge in the form of required installation rate of plants creating them, but they also require a very significant amount of carbon neutral low-cost electricity. As the direct electrification of whole transport sector by 2050 will be a challenge, support for these alternative fuels should be explored. Again, balanced measures comprising taxes and subsidies could be explored.

Biogas and hydrogen would require new infrastructure to be built (e.g. refueling stations, transport, and production). This becomes very important especially for heavy trucks using hydrogen. A clear view on hydrogen refuelling stations should therefore be included in the national hydrogen strategy. Also, support for the build-up of a hydrogen refuelling station network should be explored.

In an effort to support electrification of transport sector, new or renovated residential and non-residential buildings are mandated to implement infrastructure for EV charging (Finlex, 2020). Currently residential buildings are eligible for monetary support to enable construction of the needed charging infrastructure. A similar incentive could be expanded to non-residential buildings, especially workplaces, to further promote faster electrification.

9 Challenges in the field of transportation are currently being studied by the Finnish government. A final report by a working group (Andersson et al., 2020) and a decision in principle by the Prime Minister's Office (Ministry of Transport and Communications, 2020) have already been published.

Next steps recommendations for transport sector

- Explore balanced support measures for investments in carbon neutral vehicles – especially for low-income residences in rural areas
- Explore options to increase incentives for switching to low-carbon vehicles (e.g. renewing the transport tax and payment system and/or implementing an emission trading scheme including the transport sector)
- Explore the support for piloting synthetic fuels and hydrogen production.
- Explore options to support the build-up of hydrogen refueling stations in Finland – essential for enabling the decarbonisation of heavy road traffic.
- Explore options to enable levelling synthetic fuel cost on a par with fossil fuels.

3.7 Buildings and Services sector: Decarbonisation relies on thermal insulation and heat pump up-take for individual and district heating

Key takeaways

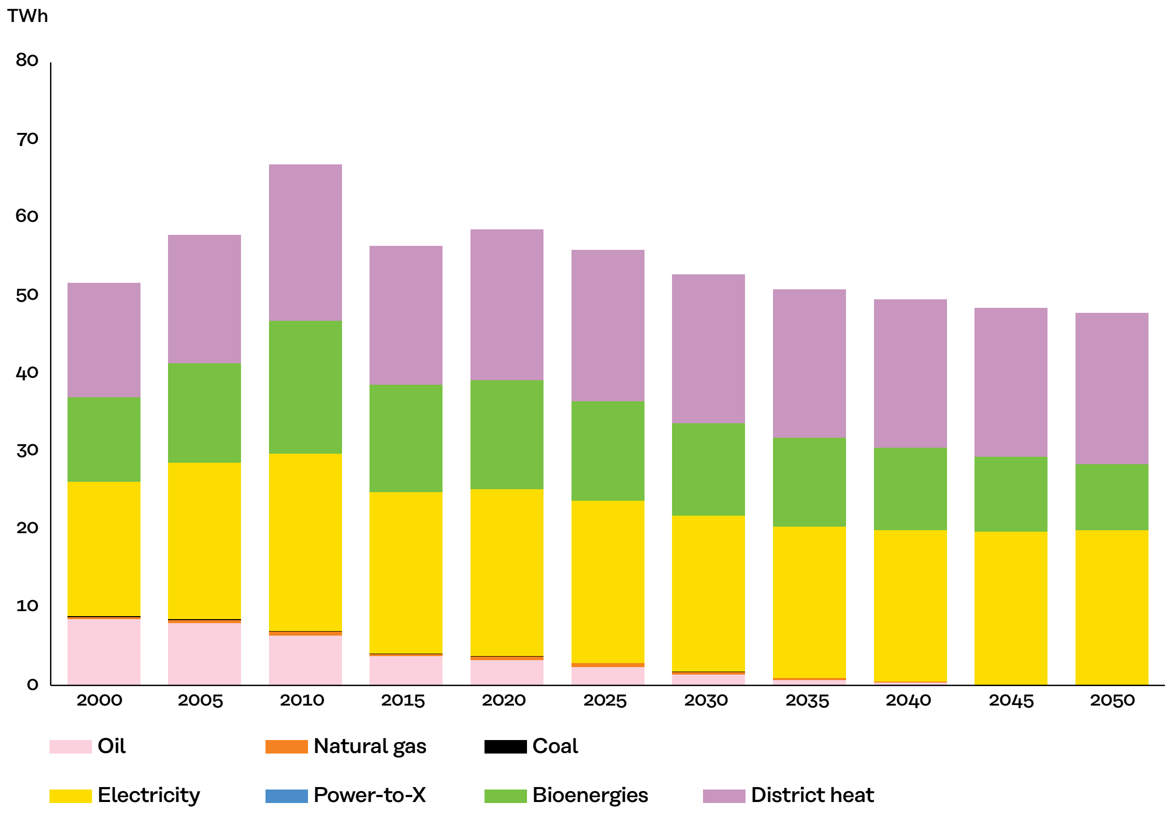
- Direct electrification, and especially the use of heat pumps, will allow full decarbonisation of buildings' energy consumption, along with maintained use of bioenergy and decarbonisation of the district heating supply.
- Electric heat pumps will also be progressively deployed for district heat production; in the medium term, bio-based district heat enables to phase-out fossil fuel quickly, before getting back to its historical level with the push of electrification.

This sub-section presents the results of the study relative to the buildings and services sector, and the potential bottlenecks, enablers and recommendations for the decarbonisation of buildings and services.

3.7.1 Buildings and services full-energy balances

The cost-efficient decarbonisation of the buildings sector will happen mostly via direct electrification, with a wide-spread deployment of electric heat pumps. With no envisioned PtX opportunities in the buildings sector, results are similar in the direct electrification and the increased PtX scenarios.

Figure 33: Final energy consumption of households by energy carrier, identical in the Direct Electrification and Increased PtX Scenarios



Source: POLES-Enerdata model results by Enerdata

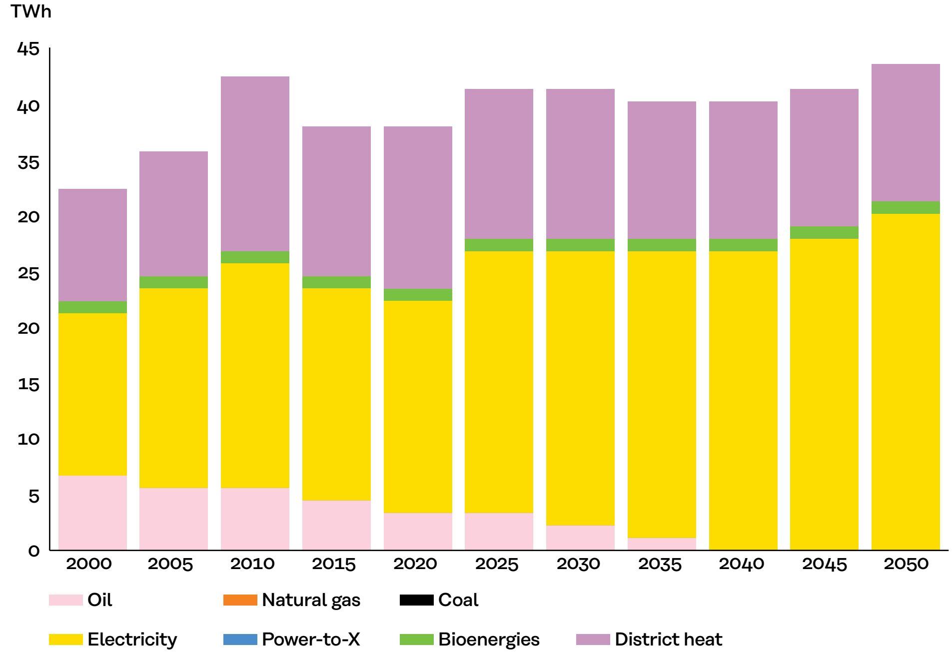
Both scenarios see final energy consumed by households decrease from 57 TWh in 2015 to 48 TWh in 2050 (-0.5% per year on average), as illustrated in Figure 33.

Despite the increasing specific electricity uses (+2 TWh over the period), electricity demand slightly decreases (-2 TWh) due to a switch to more efficient heating equipment in the form of heat pumps (ambient/ground heat is not accounted for): **by 2050, heat pumps would represent over 90% of electricity consumed for heating uses.** District heating demand would remains stable over the period at around 20 TWh, and bioenergy use for heating decreases from 14 TWh to 8 TWh over 2015-2050.

Services energy consumption would slightly increase, from 35 TWh to 38 TWh (+0.3%/year on average), as described in Figure 34. Electricity consumption in commercial buildings would be driven by increasing specific uses (21 TWh in 2050, +4 TWh since 2015), including digitalisation and data centres. In addition, heating needs are met by both electric systems (5 TWh in 2050) and district heating (11 TWh).

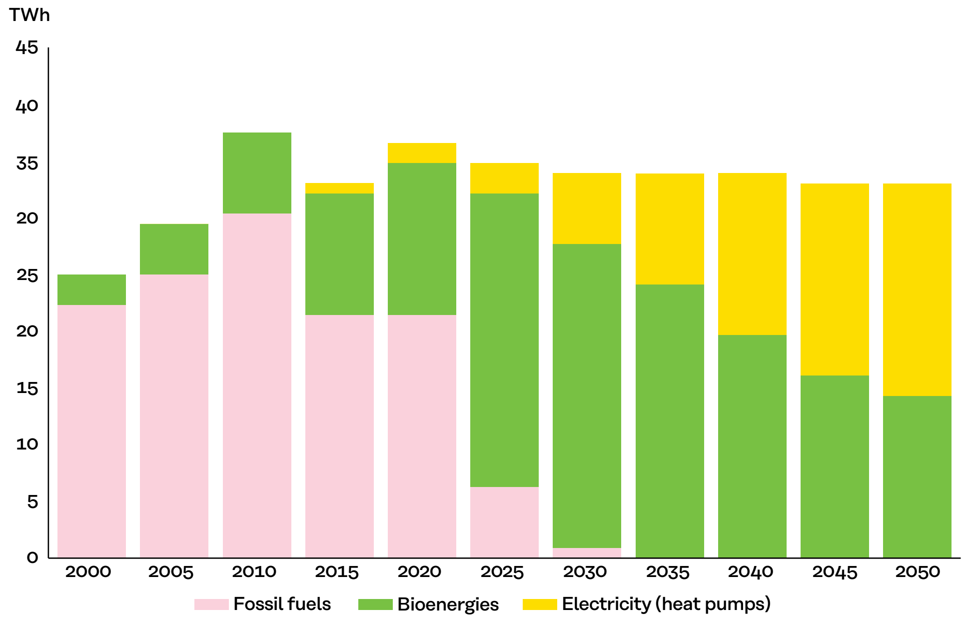
Electrification would also enable the decarbonisation of the district heating sector, through a gradual penetration of heat pumps.

Figure 34: Final energy consumption of services by energy carrier, identical in the Direct Electrification & Increased PtX Scenarios



Source: POLES-Enerdata model results by Enerdata

Figure 35: District heat supplied by energy source, identical in the Direct Electrification & Increased PtX Scenarios



Note: The energy sources for the heat pumps category are electricity and waste & ambient heat. Peat is part of the "Fossil" category.
Source: POLES-Enerdata model results by Enerdata

Total district heat supplied, as shown in Figure 35, would be roughly stable over the period, reaching 37 TWh by 2050.

The use of fossil fuel for district heat generation will be rapidly and fully phased out (before 2035), from 24 TWh in 2015 (over 60%) in both scenarios. The current fossil fuel-based heat supply would be progressively replaced by bioenergy, especially in the short to medium term. Biomass for this short time increase is assumed to be obtained from forestry, forest industry by-products and possibly from agriculture and imports. The share of bioenergy then decreases as electric-based heat starts to increase significantly, and bioenergy eventually provides 16 TWh of district heat by 2050, from 12 TWh in 2015. The uptake of electric heat pumps will progressively happen and enable to provide the rest of the decarbonised district heat supply, reaching 21 TWh in 2050 (around 55%). The heat pumps are assumed to run using waste heat, ground heat or seawater heat as heat source.

3.7.2 Key bottlenecks and enablers in buildings & services

One of the major changes in the building and service sector will be change-over part of the district heating from CHP and boiler-based heating towards large heat pumps. Legislation changes regarding moving district heating heat pumps into industrial tax rate should be finalised as soon as possible. Furthermore, it should be explored whether lowering tax rate on heat pumps would be enough to enable electrification of district heating.

Heat pumps will also require a heat source to utilise. In the service sector, new heat sources are emerging in form of heat capture from shopping malls, data centres and other similar buildings. District heating could receive major new heat source from electrolyser plants, if they are located near district heating network. Ambient heat is utilised in smaller heat pumps and this will most likely also be expanded to district heating heat pumps. Shifting heating to electricity also brings additional flexibility capacity for the power system, especially if the heating systems also have heat storages. Sufficient support should be provided to piloting projects where district heating networks are would be converted to utilise heat pumps, waste heat, and low heat solutions.

Underlying the building sector transformation are assumptions of energy efficiency improvements. If these efficiency improvements do not take place, heating related energy consumption will most likely increase beyond the projected scenarios. This would also affect peak demand of generation and would require additional peaking capacity. Investing into at least some energy efficiency improvements should be profitable in most cases, as they will directly reduce cost of energy. In addition, behavioural changes will have an impact on total use of energy. For example, lowering the room temperature during winter could directly reduce total needed energy. For both residential and commercial buildings, efficiency improvements can be made easier with automation. Especially large buildings in the service sector have a great opportunity to reduce energy use in air conditioning, heating, and lighting by optimising these resources with automation. With automation, these same loads can also offer flexibility. These energy efficiency improvements should be captured especially in service sector.

Next steps recommendations for buildings and services sector

- Explore the support of (piloting) projects for the transformation of existing district heating networks for the utilisation of heat pumps.
- Explore the support of (piloting) projects for waste heat capturing for district heating, e.g. data centres and electrolysers.
- Explore (additional) support for improving energy efficiency buildings as well as investments into automation, distributed energy resources, or other energy efficiency improvements.
- Increase information provision and education for energy consumers about energy efficiency and related benefits.

4 Supply side: Cost-efficient and secure electrification requires deployment of significant low-carbon generation capacities and flexibilities

This section presents the results of the supply side analysis of the Finnish power sector evolution until 2050, and the essential supply side results for this cost-efficient Direct Electrification Scenario, contrasting them with results for the Increased PtX Scenario.

The section is structured as follows: After an overview of the assumptions to derive the cost optimal generation evolution and the respective results, we explore the requirements for supply side flexibility and the role of Finnish power imports. We then discuss the effects of electrification on transmission and distribution grids. Next, we present the required power system investments and the effects on electricity system costs and prices. The properties of the Finnish electricity system regarding security of supply with ever increasing renewable shares and regarding the evolution of carbon emissions are illustrated. We conclude with the results of the two sensitivity analyses exploring the effects of restrictions to wind capacity build-ups and the effects of limitations to the up-take of demand-side flexibilities.

4.1 Generation mix: The cost-efficient mix will require significant expansion of low carbon generation capacities, especially onshore wind

Key takeaways

- In the cost-optimal generation mix for the Direct Electrification Scenario, onshore wind will become the dominant power generation technology from 2035 onwards, amounting to 70% of all installed generation capacities and 73% of all domestic generation by 2050. Despite higher capacity factors offshore wind capacities are not significantly expanded due to the higher overall levelized cost of electricity generation.
- This scenario requires significant storage capacities – approximately 6 GW of P2G2P and 4 GW of batteries in 2050 – to provide the supply side flexibility needed to integrate the expanded variable renewable generation.
- Further supply side flexibility – also ensuring security of supply – is provided by 3 GW of gas-fired generation (open cycle gas turbines).
- While the Direct Electrification Scenario does not foresee new nuclear capacities beyond Olkiluoto 3 and the life-time expansions of Olkiluoto and Loviisa, in the increased PtX-Scenario additional nuclear capacities (up to a total of 2.2 GW in 2050) are required in the generation mix.

This sub-section provides a detailed description of the assumptions underlying the derived capacity evolutions and an outline of the electricity load to be covered, followed by the presentation of the resulting power generation capacities and actual power generation for both scenarios. We conclude the sub-section with a discussion of identified key bottlenecks, enablers, and proposed next steps relating to power generation.

4.1.1 Generation mix expansion assumptions: The assumptions underlying the capacity mix expansion modelling are based on recognised sources and were aligned with stakeholders

The evolution of the Finnish power generation and storage capacities derived in this study is based on various assumptions regarding, among other things, generation potentials, efficiencies, cost evolutions and interconnection capacities. These assumptions – particularly regarding wind and nuclear generation – were discussed extensively while developing the study also reflecting stakeholder feedback. The key assumptions are detailed in the tables below. The assumptions presented here are valid for both scenarios and the two sensitivities, unless otherwise stated.

The build-up of new generations and storage capacity by the CL model was limited regarding the total onshore and offshore wind potentials as well as the solar potentials. Respective assumptions on capacity potentials in 2050 were derived from (Fingrid, 2021) and are shown in Table 2. For the sensitivity analysis presented in section 4.9, reduced wind capacity potentials were considered, also outlined in Table 2.

In deriving wind capacity expansions, differentiated capacity factors were assumed per wind generation type (Table 3). Capacity factors for new onshore wind generation were based on Forsman, et al., 2021, and other capacity factors based on ENTSO-E Pan-European Climate Database.

Intermittent renewable generation depends on weather conditions. The weather conditions in 1984 (reference climate year), considered by ENTSO-E (2018) as a year with normal conditions, were used for obtaining the results of this study.

Power system evolution assumptions for the rest of Europe are based on the Ten-Year Network Development Plan (TYNDP) 2020 (ENTSO-E, 2021). Technical power parameters (including efficiencies) are based on ENTSO-E (MAF 2020 Dataset, 2020), DIW (2014), and industry insights.

The cost assumptions used in the study consider real cost decreases over time for most technologies. They are based on the European Commission's Technology Pathways study (EC, 2018; Capros, et al., 2019) – using the lower (more optimistic) ranges – and industry insights. Investment as well as operations & maintenance costs for wind (onshore, offshore), solar, and nuclear power generation technologies are presented in Table 4. For offshore-wind connection costs to the mainland grid are included in these assumptions. For all generation types costs

Table 2: Assumptions for Finnish generation capacity potentials

	Capacity potential in 2050 [GW]	
Generation type	**Baseline assumptions**	**Wind sensitivity analysis]**
Onshore Wind	54	25
Offshore Wind	25	25
Solar	22	22

Note: Baseline assumptions are used for all analyses except for the wind sensitivity analysis.
Source: Fingrid, 2021

Table 3: Assumptions for wind capacity factors

Generation type	Capacity factor [%]
Existing Onshore Wind	26.5
New nshore Wind	34.2
Existing Offshore Wind	27.4
NewOffshore Wind	47

Source: Capacity factors new onshore: Forsman, et al., 2021; Other capacity factors: ENTSO-E Pan-European Climate Database for transmission grids on the mainland are not included in these assumptions and treated separately (section 4.4.1).

In line with all other capacity expansions, new nuclear capacity expansion is endogenously determined by the model based on economic competition with other technologies. For existing nuclear capacities in Loviisa and Olkiluoto life-time extensions were considered and the start-up of Olkiluoto 3 was assumed for 2022 (Table 5).

The CL model considers the Finnish system to be embedded in the pan-European electricity system. The assumptions about the evolution of the Finnish cross-border transmission capacities outlined in Table 6 are based on the Ten-Year Network Development Plan (TYNDP)

Table 4: Power generation cost assumptions

Cost parameter	Capacity type	2025	2030	2035	2040	2045	2050
Specific Investment (CAPEX) [€/kW]	Onshore Wind	1099	995	947	898	866	833
	Offshore Wind	2222	2025	1962	1898	1824	1750
	Nuclear	5000	5000	4900	4750	4700	4700
	Solar	653	580	571	511	483	455
Fixed operation & maintenance cost (FOM) [€/kW]	Onshore Wind	25	18	18	18	18	18
	Offshore Wind	80	50	50	35	35	35
	Nuclear	85	85	85	85	85	85
	Solar	10	10	10	10	10	10
Variable operation & maintenance cost (VOM) [€/MWh]	Onshore Wind	0	0	0	0	0	0
	Offshore Wind	0	0	0	0	0	0
	Nuclear	5	5	5	5	5	5
	Solar	0	0	0	0	0	0

Source: Technology pathways in decarbonisation scenarios (EC, 2018); and industry insights

Table 5: Nuclear closings and openings

	Capacity [MW]	All scenarios and sensitivities
Existing Units		Closing Date
Loviisa 1	488	2037
Loviisa 2	488	2040
Olkiluoto 1	885	2038
Olkiluoto 2	880	2040
New Units		Opening Date
Olkiluoto 3	1600	2022

Source:Assumptions aligned during study development

(ENTSO-E, 2021) and Mid-term Adequacy Forecast (MAF) 2020 for the period 2020-2030 (ENTSO-E, 2020).

In deriving generation and storage capacity requirements, available demand side flexibility (DSF) is considered. The respective assumptions are based on RTE (2019), ENEL (2020) and RTE (2020). An overview of the resulting DSF capacities is outlined in Table 7. For the sensitivity analysis presented in section 4.10.2 reduced DSF uptake was considered that are also outlined in the Table 7. More detail on the DSF assumptions is given in section 4.10.3.

In general, basing this study on a different set of power system assumptions than those outlined above would affect the findings. For instance, choosing a windier climate year or higher capacity factors for onshore wind could increase future power exports or reduce wholesale power prices in Finland. However, the used assumptions are based on transparent, reliable and consistent pan-European and Finnish sources and the resulting evolution of the generation mix derived from them can be interpreted as conservative rather than optimistic.

Table 6: Cross-border transmission capacity assumptions[1]

Capacity [MW]	2020	2025	2030	2035	2040	2045	2050
FI-EE	1016	1016	1016	1516	1516	2016	2016
FI-SE	2730	3200	3200	3200	4700	6500	6500
FI-NO	0	0	0	500	500	1000	1000

Source: Compass Lexecon, based on Ten-Year Network Development Plan (TYNDP) (ENTSO-E, 2021)

Table 7: Assumptions on the availability of demand side flexibility (DSF)

	DSF potential in 2050 [GW]	
Scenario	**Baseline assumptions**	**constrained DSF sensitivity analysis**
Direct Electrification Scenario	12	6.5
Increased PtX Scenario	14.7	7.8

Note: Baseline assumptions are used for all analyses except for the DSF sensitivity analyses.
Source: Compass Lexecon

1 Finland has currently also interconnection lines with Russia and Norway which are not modelled in this study.

4.1.2 Electricity load: Increasing Finnish electricity demand to be satisfied is the main driver for generation capacity expansion needs

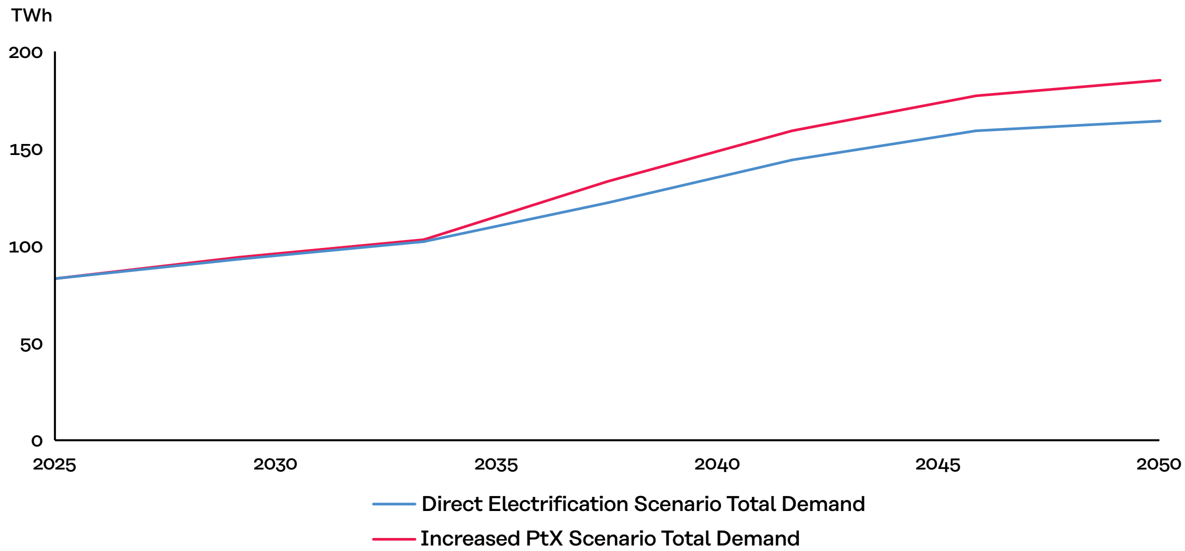
The evolution of Finish electricity demand is ascertained from the overall energy balances modelling outlined in Section 3. The annual quantities are transformed into hourly load-curves based on the evolution of the demand composition. Thereby, typical profiles for the various demand types (e.g. lighting, EVs, heat-pumps, hydrogen production) are considered. Besides end-user demand, domestic generation and imports thereby also have to cover transmission and distribution losses, which were considered and increased the two scenario loads slightly (~3%) compared to the amounts presented in Section 3. In 2050 the load to be covered reaches 159 TWh in Direct Electrification Scenario and 179 TWh in the Increased PtX Scenario (Figure 36).

Finnish peak demand increase from 15 GW in 2025 to 24 GW (Direct Electrification Scenario) and almost 25 GW (Increased PtX Scenario) in 2050 (Figure 37).

When modelling the electricity demand its flexibility is also considered. Replacing dispatchable fossil-fired power plants with intermittent renewable generation drives the need for system flexibility in order to maintain the balance between electricity consumption and production at all times. This flexibility can either be provided on the supply side (e.g. dispatchable renewable generation like hydropower or grid-level storage) or on the demand side with end-users shifting consumption away from peak-demand times.

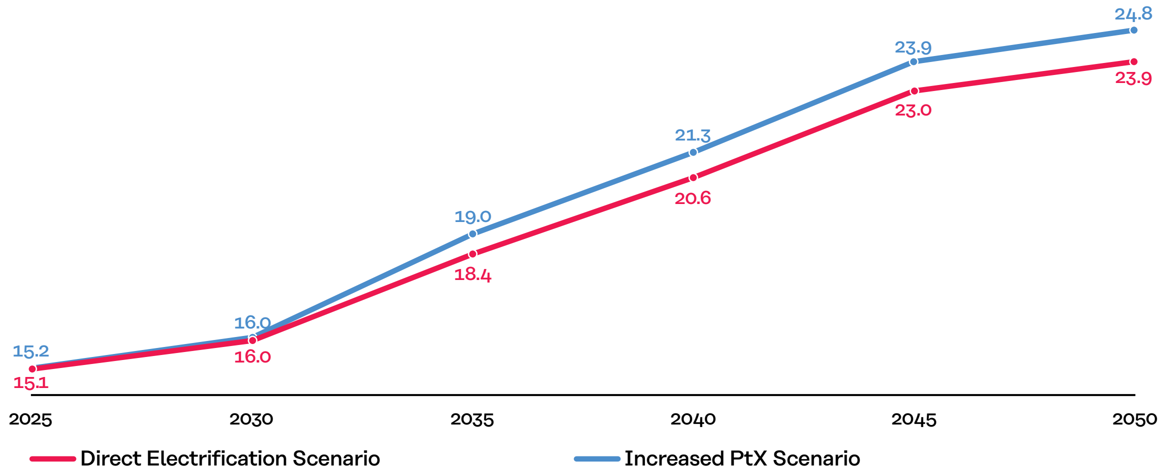
Demand side flexibility potentials are characterised by two parameters: (a) the load reduction potential and (b) the time over which the load can be reduced. Both parameters are characteristics of the respective end-user type offering flexibility (Figure 38).

Figure 36: Total annual electricity demand [TWh], Direct Electrification & Increased PtX Scenarios



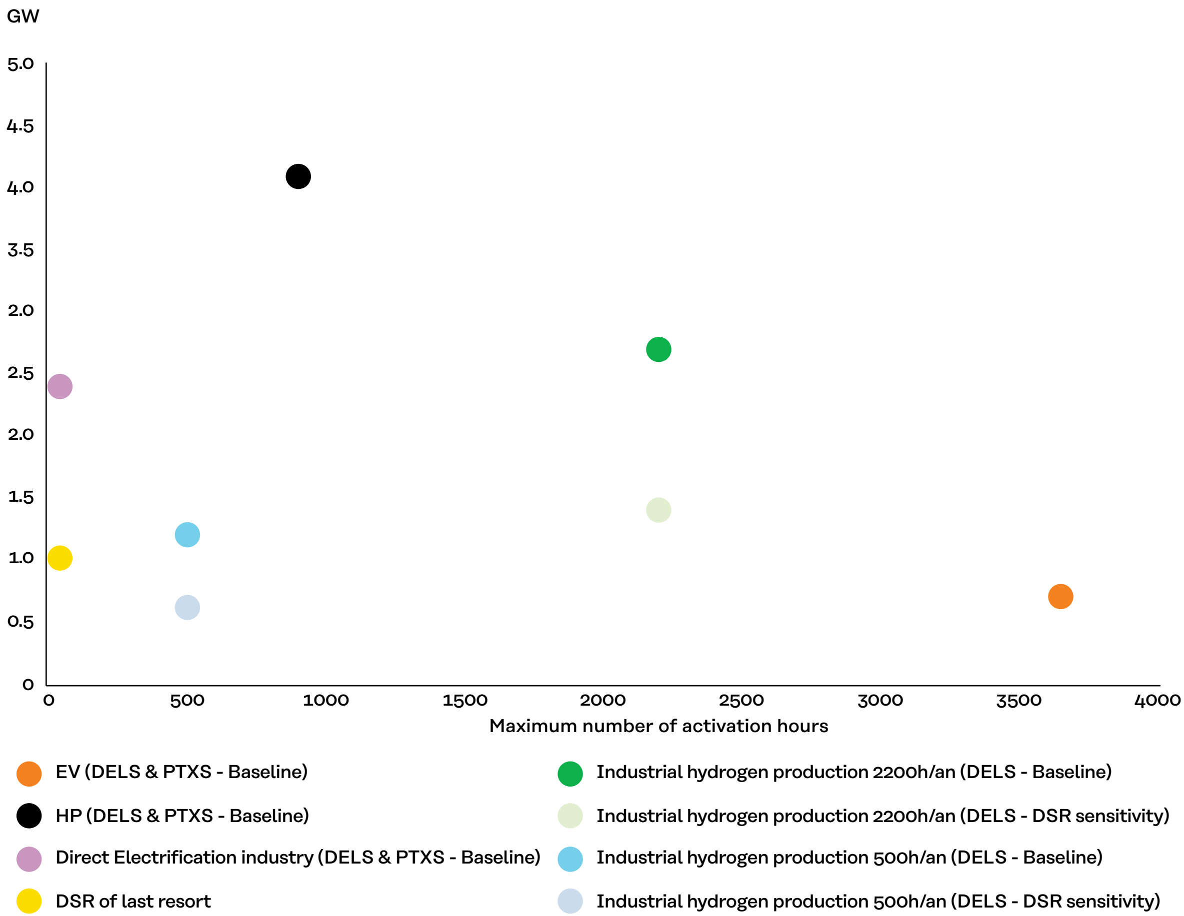
Source: CL power dispatch model results by Compass Lexecon

Figure 37: Finnish annual electricity peak demand evolution [GW], Direct Electrification & Increased PtX Scenarios



Source: CL power dispatch model results by Compass Lexecon

Figure 38: Demand-side flexibility potentials in 2050 – baseline values



Source: Compass Lexecon

The study considers, demand side flexibility across all sectors:

— in the building sector electricity demand for heat pumps is considered;
— in the mobility sector shifting charging times of EVs provides DSF;
— in the industrial sector parts of the electricity demand for industrial processes are already flexible in the form of demand side response (DSR) of last resort (i.e. interruptible supply) and with increasing electrification parts of the new process demand can also provide flexibility. In the industrial sector, however the ability of continuous process industries (like steel production or the chemical industry) to provide DSF remain limited;
— in the energy sector shifting the times for hydrogen production provides flexibility.

A sensitivity analysis regarding the underlying assumptions was carried out to assess the importance of demand side flexibility for cost-efficient decarbonisation (section 4.10).

4.1.3 Generation (capacity) mix: In 2050 onshore wind and flexibilities dominate in both scenarios

4.1.3.1 Direct Electrification Scenario

The capacity expansion modelling minimises the total system costs to satisfy the demand by simultaneously optimising the capacity build-up and dispatch of dispatchable capacities within specified constraints (e.g. capacity potentials, emission limits, interconnection capacities). The resulting capacity mix is therefore generally reflective of the levelised cost of electricity (LCOE) production (or storage). LCOE accounts for capital costs, operation and maintenance costs and fuel costs (where applicable) and spread the sum of these cost over the annual production.[1] Table 8 presents the LCOE for various renewable generation technologies whereby only capacities built in the respective year are considered when deriving the figure (i.e. existing and still operating capacities which were built earlier and included in the previous calculations are not considered in Table 8).

Table 8: LCOE (€$_{2020}$/MWh) of renewable technologies deployed in the respective years, Direct Electrification Scenario

Generation technology	2025	2030	2035	2040	2045	2050
Onshore Wind	38	33	32	31	30	29
Offshore Wind	80	66				
Solar	57	52	51	47	45	

Source: CL power dispatch model results by Compass Lexecon

1 The concept of levelised costs of electricity is explored in more detail – including on a system-wide level – in section 4.6

LCOE variations over time result from changes in build-up costs (CAPEX) and the respective technologies annual generation volumes. Up until 2050 onshore wind is the cheapest generation technology. Offshore wind is significantly more expansive due to higher investment (accounting for connection to the mainland grid) and despite higher capacity factors.

In the Direct Electrification Scenario **the installed power generation capacity in Finland would more than triple by 2050** – increasing from slightly below 20 GW in 2020 to 72 GW (Figure 39). In **2050 more than 47 GW onshore wind represents almost 70% of all capacities**. The build-up therefore stays below the specified potential of 50 GW, despite higher capacity factors and a potential of 25 GW, offshore wind build-up remains limited (1 GW in 2050). The development of offshore wind and solar power stays limited, with installed capacities equal to 1 GW and 2 GW in 2050, respectively.

Based on the modelled cost-efficient result, **nuclear capacity would not be expanded beyond Olkiluoto 3** (OL3). OL3 is therefore the only remaining nuclear capacity in the Finnish power system after 2040 when Olkiluoto 1 (2038) and 2 (2040), and Loviisa 1 (2037) and 2 (2040) would retire after the end of their life-time expansion (see assumptions in section 4.1.1).

Significant supply-side flexibility resources (storages) enable the integration of variable renewable generation and ensure security of supply. Batteries and Power-to-Gas-to-Power (P2G2P) are therefore important new capacity elements in the future Finnish electric system. Batteries ensure short-term flexibility whereas P2G2P delivers longer-term seasonal storage. The importance of storages grows after the phase-out of coal and other thermal capacities in 2030, and especially after 2040 when the ageing nuclear capacity retires, and onshore wind capacity continues to grow. By 2050 approximately **6 GW of P2G2P and 4 GW of batteries are deployed**. Additional flexibility is provided by expanded cross-border interconnectors and around 3 GW of clean gas (hydrogen and biogas) generation.

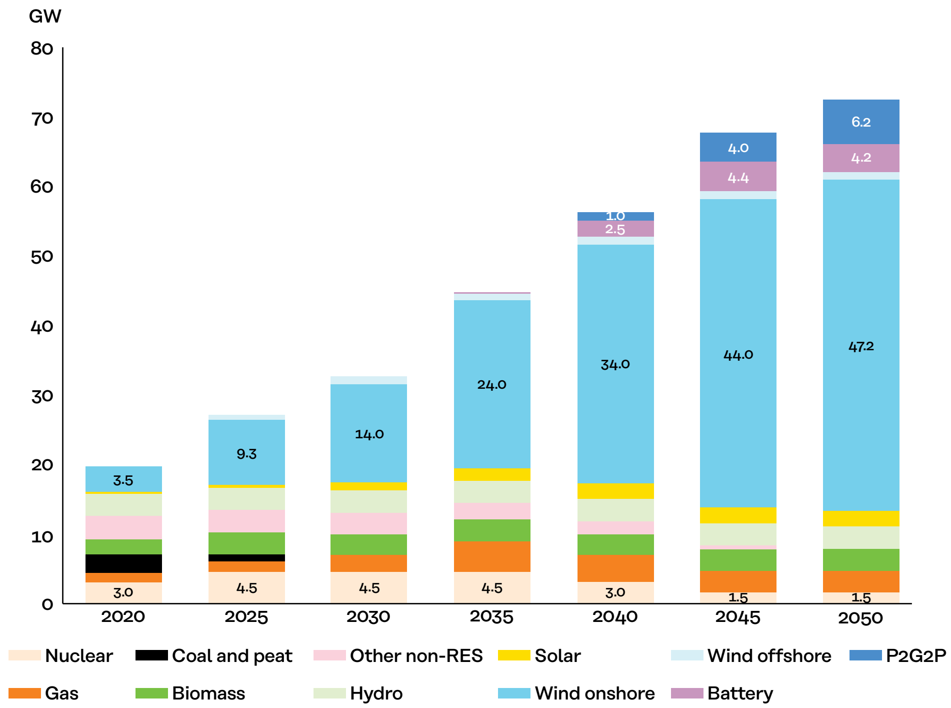
Following the capacity expansions, from 2035 onwards **power generation becomes dominated by onshore wind which would reach a 73% generation share in 2050** (Figure 40). Biomass generation remains stable in the long-term (approximately 10TWh), but increases in the short-term up to a maximum of 14 TWh in 2025[2]. Hydropower stays stable throughout the whole period, generating approximately 14 TWh annually. Nuclear power generation would peak in 2025 to cover over a third of the annual power load in Finland but declines to approximately 6% in 2050.

Two important structural changes until 2050 are apparent. First, **Finland would become a net exporter of electricity in the mid-term**. Compared to today, where approximately a fifth of the Finnish annual load is imported, the net import balance will shift to approximately 3 to 4 TWh of net exports between 2030 and 2035. Further details are discussed in section 4.3.1.

The second structural shift is represented by the **increasing divergence between the system (gross) load and the customer (net) load** as visibly pronounced from 2040 onwards (Figure 40). The system load, which includes net consumption from storages, becomes increasingly higher than the pure customer load. This difference of almost 14 TWh in 2050 is mainly made-up by losses of the P2G2P conversion process.

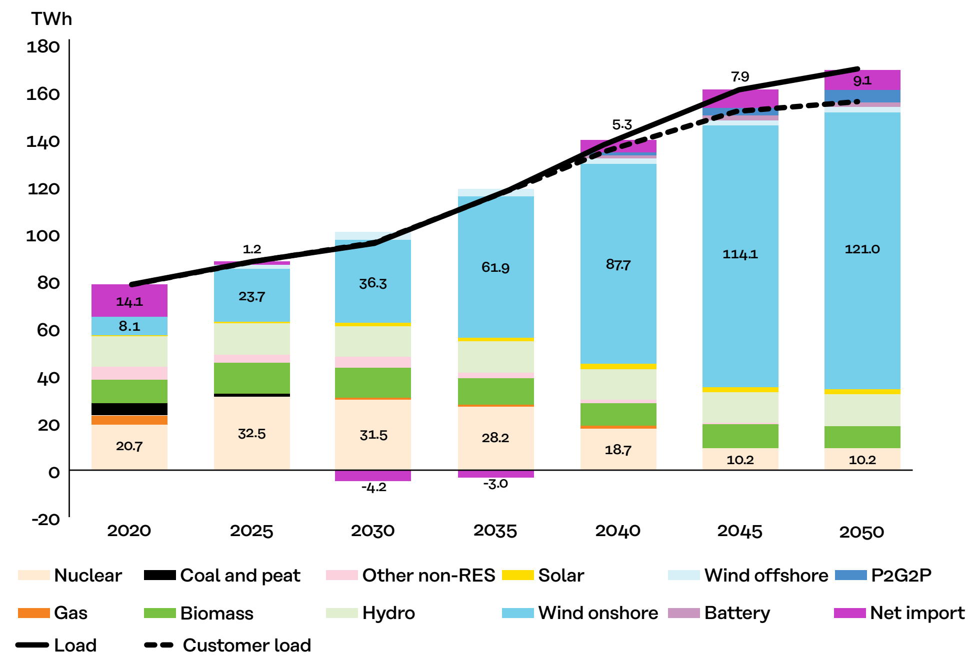
2 This is assumed to mainly involve increased biomass CHP usage and partly also re-utilising peat plants for biomass usage while no major build-up of dedicated biomass capacities are assumed.

Figure 39: Installed capacity in the Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

Figure 40: Power generation in the Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.1.3.2 Increased PtX Scenario

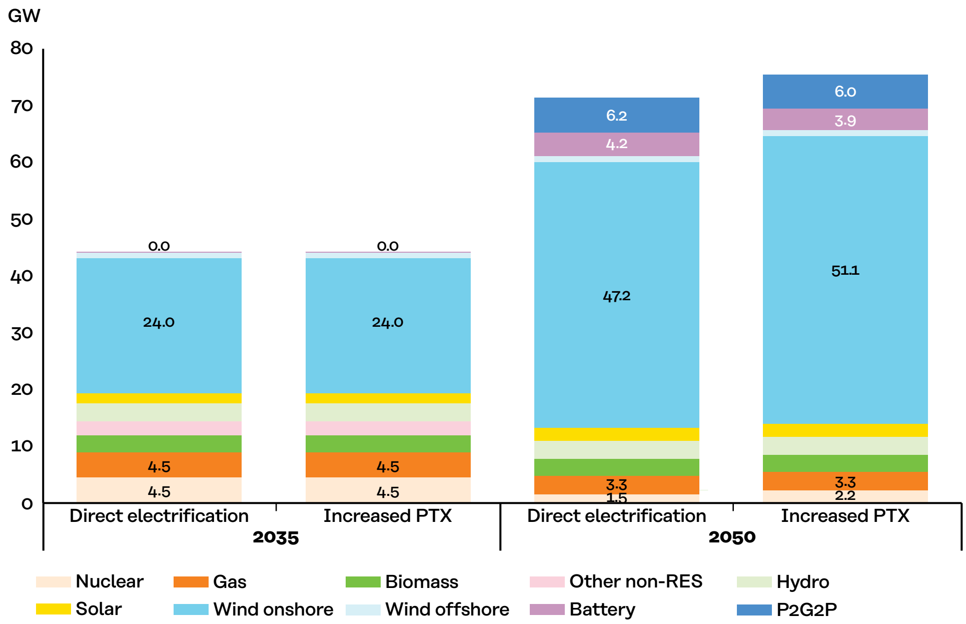
In the Increased PtX Scenario the installed capacities (Figure 41) would further increase to satisfy the additional demand compared to the Direct Electrification Scenario, with the **total generation capacity reaching 76 GW by 2050**. Compared to the Direct Electrification Scenario the additional demand would be mostly met by a combination of additional onshore wind and nuclear capacity. The additional nuclear power plant is expected to come online by 2040.

Also, in the increased PtX Scenario, generation consists mostly of **onshore wind representing 72% of to the total generation in 2050**. The additional demand (+20 TWh in 2050) compared to the Direct Electrification Scenario (Figure 42) would be met by a combination of additional onshore wind (+10 TWh), nuclear power (+5 TWh) and imports (+6 TWh).

4.1.4 Key bottlenecks and enablers for power generation

Compared to the historical average build-up in Finland (over the past decade 0–500 MW per year), the wind capacity increases in both scenarios are very significant. Wind farm construction is relatively quick, but permitting can take a couple years (Suomen Tuulivoimayhdistys, 2019). Public acceptability can be a major limitation in the permitting as the number of turbines increases. Moreover, permitting delays can lead to situations where permitted turbines are smaller than current state-of-the-art ones. Permitting time could be reduced by streamlining the process and increasing administrative resources. The scope for later-stage adaptations of e.g. turbine size or exact location within zones might reduce adverse repercussions of long permitting times. Public

Figure 41: Installed Capacity, comparison between the Direct Electrification and the Increased PtX Scenarios



Source: CL power dispatch model results by Compass Lexecon

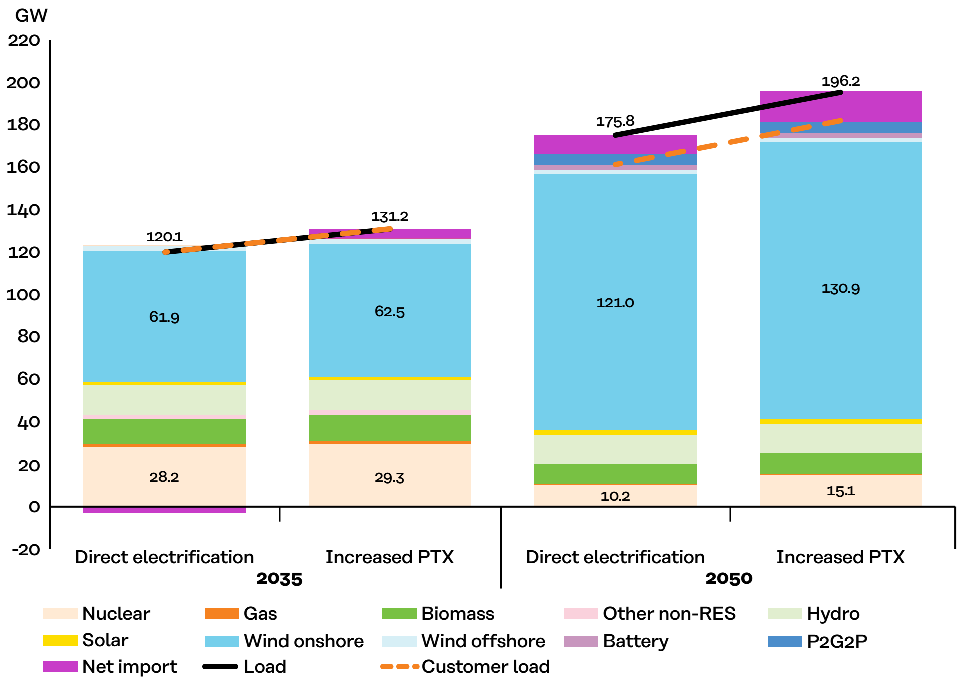
acceptability could be improved e.g., by informing about the economic benefits that wind farms bring to a municipality.

Finnish Defence Forces regularly impose restrictions on wind generation build-up to avoid radar interference. These restrictions might ultimately require significant deviations from the cost-efficient decarbonisation pathway. While there is a variety of measures discussed to reduce or avoid radar interference (new calculation models, construction of additional radars (Lauritsen et al, 2016) or to improve the capabilities to withstand electromagnetic interference (Gilman et al., 2016; Dixon, 2018), their feasibility in the Finnish context is disputed. Further analysis therefore seems mandatory. Moreover, stakeholders have voiced the need for more flexible interactions with the Defence Forces allowing for easier adaptations to initially denied wind projects. The effects of such restrictions are further explored in sensitivity analyses of the main scenarios (section 4.9).

Beyond permitting, the grid connection of wind farms can pose a significant bottleneck to large scale capacity expansion. To limit respective bottleneck that delays in building transmission grids bring, it would be beneficial to map future locations of wind farms and start planning the expansion as early as possible. This would allow connections not to a become limiting factor for new capacity. The challenges of transmission grid expansions are further explored in section 4.2.

Both scenarios rely on life-time extensions for the existing four Finnish nuclear reactors in Olkiluoto and Loviisa until the end of the 2030s. Olkiluoto 1 and 2 have already been granted the lifetime extension until 2038, but the Loviisa reactors have not yet received the extension permits beyond

Figure 42: Generation, Comparison between the Direct Electrification and the Increased PtX Scenarios



Source: CL power dispatch model results by Compass Lexecon

2030. While the permitting process for Loviisa reactors has already started, it is yet unclear if the lifetime extensions will ultimately be realised. Planning for situations where the lifetime of reactors in Loviisa are possibly not extended is therefore advisable to avoid undermining the pathway to Finnish decarbonisation via electrification.

Next steps recommendations for power generation

- Explore measures to structurally reduce the impact of the Finnish Defence Forces' requirements on the build-up wind generation capacities (e.g. setting out restrictions in advance, having more transparent discussions on building plans, researching and developing solutions to limit interference to army radars by wind turbines)
- Explore measures to reduce the effects of long permitting processes for wind parks (e.g. potential increase public administration permitting capacity or courts' resources to handle complaints)
- Follow the process of nuclear life-time extension permitting and timely explore options for substituting nuclear generation, if life-time extensions are not expected to be granted.

4.2 Supply side flexibility: Integrating intermittent wind generation will require significant traditional and novel supply side flexibility

Key takeaways

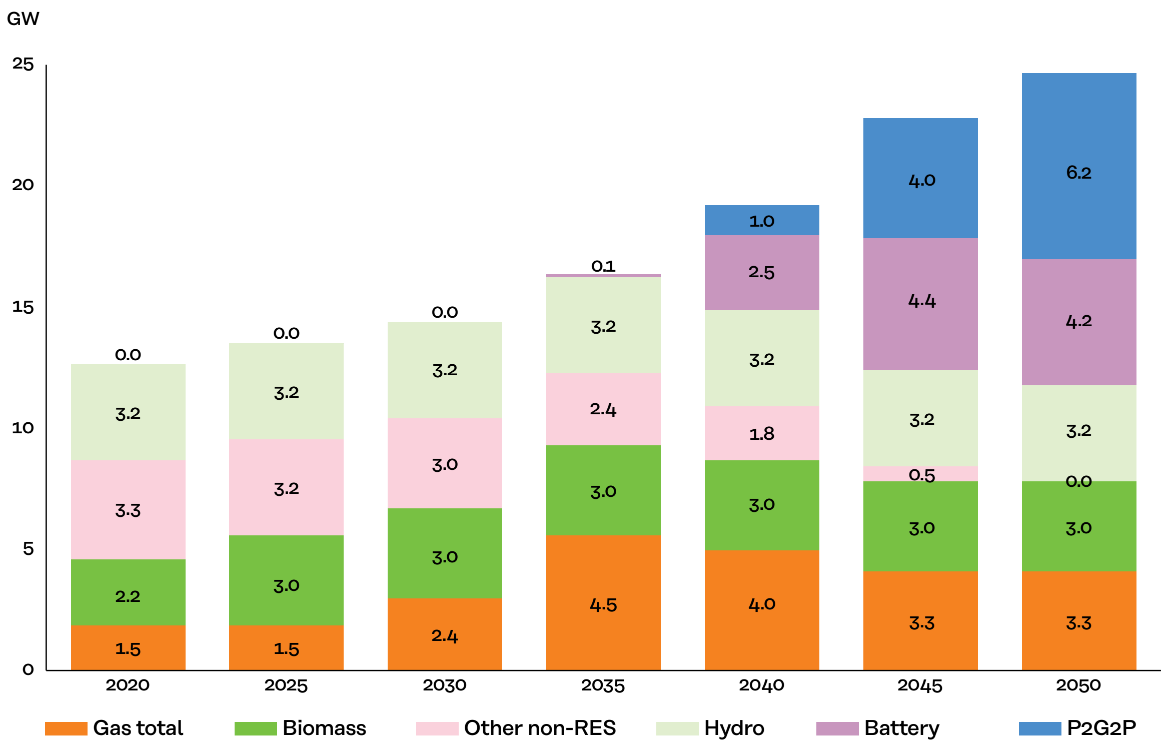
- Significant new domestic supply-side flexibilities are required to balance the increasing intermittent wind generation and replace retired fossil generation.
- From 2040 onwards power-to-gas-to-power (P2G2P) capacities will provide weekly and longer-term flexibility and batteries provide intraday flexibility to balance wind generation.
- Throughout the entire period up until 2050 significant (clean) gas fired generation is required to ensure security of supply, while producing only limited quantities of electricity.
- An important potential bottleneck might be the availability of storage capacities for hydrogen required for the P2G2P capacities – interconnection with European (clean) gas infrastructure might provide relief.

This section discusses the role of supply side flexibility based on examples of long-term (Power-to-Gas-to-Power) and short-term (battery) storage usage in the direct electrification scenario.

4.2.1 Up until 2050 significant supply side flexibility will be required

With expanding wind generation and declining dispatchable generation capacities, the importance of electricity storage increases. This is reflected in the greater storage capacities installed in the Direct electrification scenario starting in 2035 (Figure 43). These storage capacities – together with imports, dispatchable generation (hydro, biomass and clean gas as well as to some extend new nuclear generation which is assumed to be able to provide downward-flexibility of up to 80% of its name-plate capacity (Morilhat, 2019)) and demand side flexibility – balance variable wind generation. Due to limitations on the expansion of hydro and biomass generation, storage capacities make up more than 50% of domestic supply-side flexibility in the Direct Electrification scenario.

Figure 43: Installed capacity (GW) of domestic storage and dispatchable generation, Direct Electrification scenario



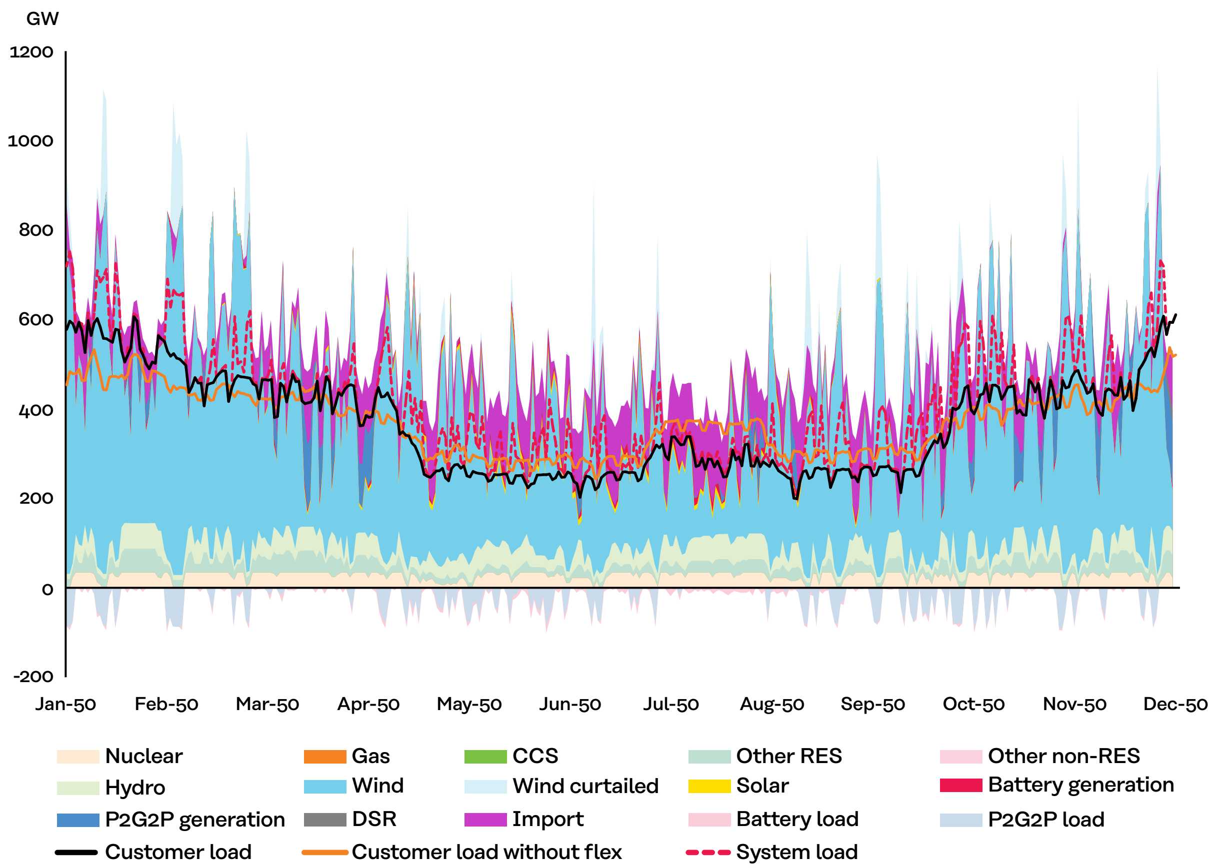
Source: CL power dispatch model results by Compass Lexecon

4.2.2 Long-term storage: Power-to-Gas-to-Power provides especially weekly flexibility to balance variable wind generation

Power-to-Gas (P2G) is utilised to store excess electricity from onshore wind power by producing and storing hydrogen. In turn, Gas-to-Power (G2P) is utilised when the generation from onshore wind power is low, ensuring – together with electricity imports – the balancing of the power system. In total hydrogen storage of almost 5 TWh by 2050 would be required for P2G2P usage. The optimal dispatch of P2G2P leads to a **multi-week** and a **seasonal arbitrage** by the P2G2P capacities. Due to the seasonality of wind generation somewhat correlating with winter peak (heating) demand, the multi-week arbitration is more pronounced. This multi-week arbitration occurs basically throughout the year (Figure 44).

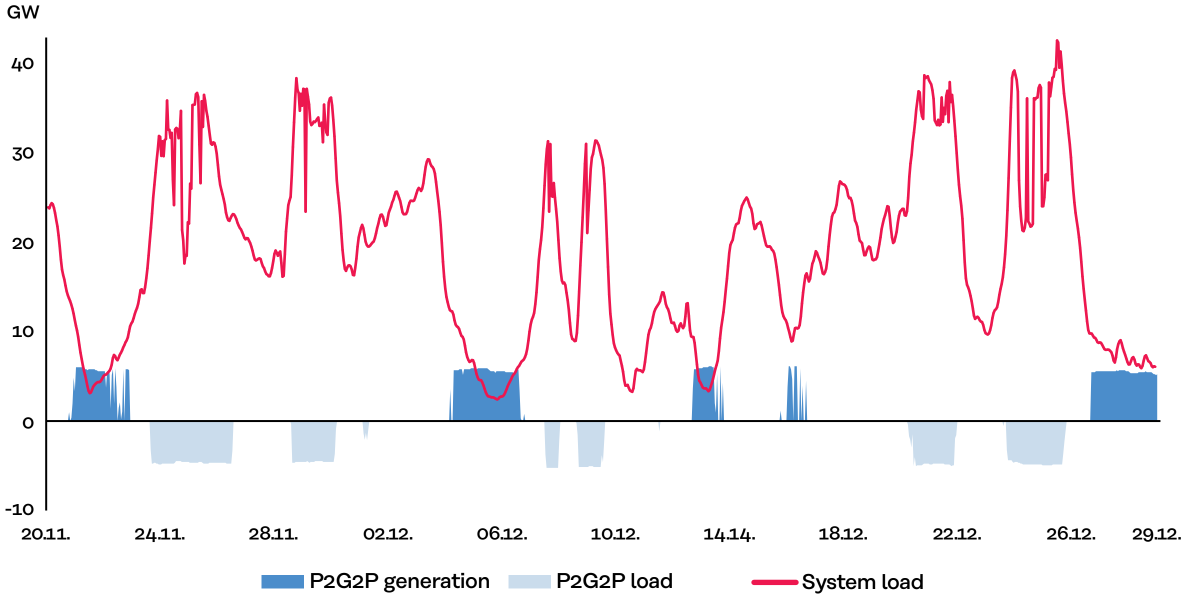
The cycle of hydrogen production during times of excess wind generation and the subsequent production of electricity from hydrogen only a few days later is nicely illustrated in November and December 2050 (Figure 45).

Figure 44: Daily generation mix for the full year 2050 (GWh/d) with the P2G2P utilisation in red – Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

Figure 45: Illustration of Finnish P2G2P generation with wind production during 40 days in November/December 2050, Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.2.3 Short-term storage: Batteries balance intra-daily generation fluctuations

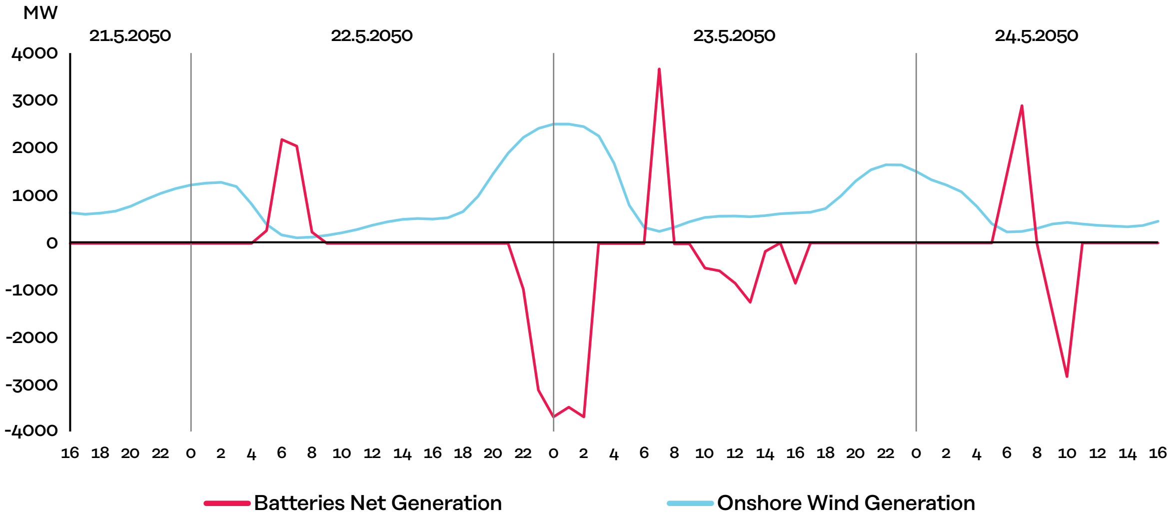
Battery capacities satisfy short-term flexibility needs of the power system. The batteries in the studied system have a storage capacity of 4 hours full injection leading to a total battery storage volume of about 17.6 GWh in 2040 and slightly less in 2050. Their charge/discharge cycle therefore fits within the same day. They can therefore be used only for intra-day arbitrage, leaving longer-term arbitrage to Finnish P2G2P capacities or pumped hydro across the Nordics.

Batteries' charge and discharge generally follows wind generation as is clearly illustrated by battery operation during three days in May 2050 (Figure 46). Batteries charge (net generation is negative) when onshore wind generation is high and discharge (net generation is positive) when onshore wind generation is low.

4.2.4 (Clean) gas-fired generation: Significant gas-fired capacities provide supply flexibility over very few hours per year

Fossil based gas-fired generation will be phased out due to the decarbonisation requirements. Clean gas-fired generation will replace them in the capacity mix, using hydrogen, biogas, and synthetic methane. They provide supply-side flexibility, however, in only a very limited number of hours per year. They also support security of supply by acting as reserve capacities. The Direct Electrification Scenario foresees new gas-fired generation capacities as late as 2035 (Figure 47). This trend is reflected in Figure 48 with an increase of gas-fired electricity generation from 2025 until 2040 followed by a sharp decrease.

Figure 46: Onshore wind generation and battery net generation profile over 3 days in May 2050 (MW), Direct Electrification Scenario



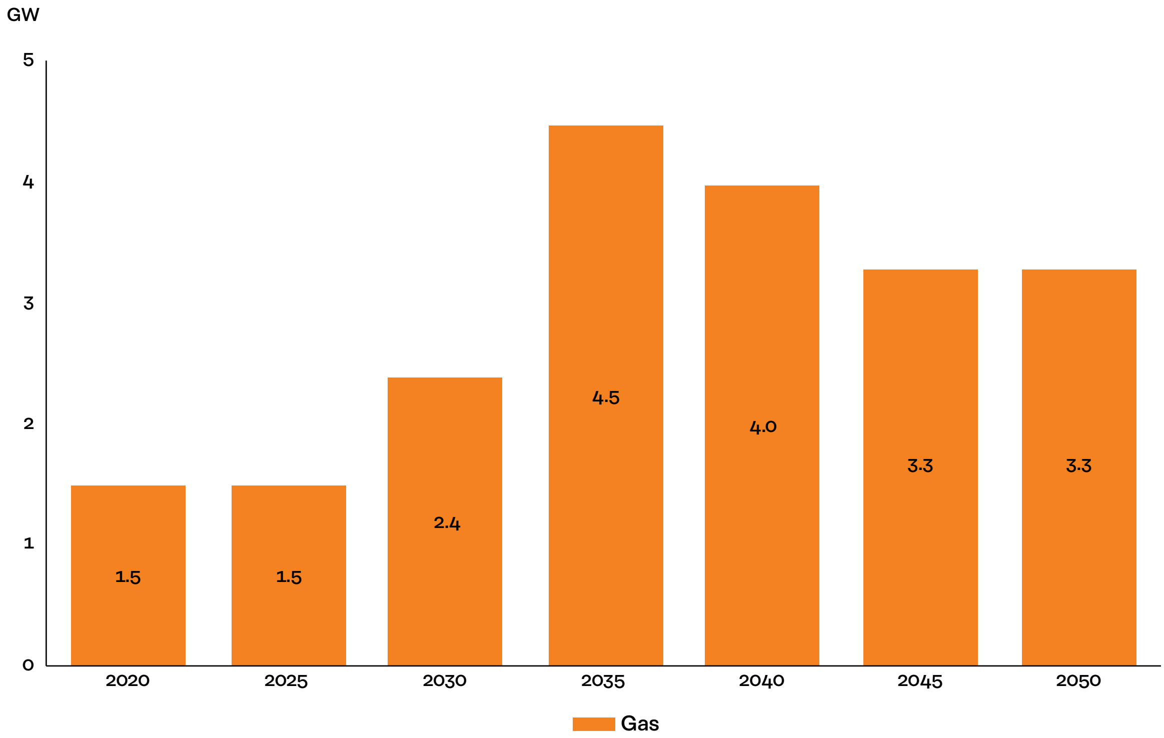
Source: CL power dispatch model results by Compass Lexecon

4.2.5 Key bottlenecks and enablers for supply-side flexibility

While the demand for additional supply-side flexibility in the ever more decarbonised Finnish electricity system would increase up until 2050, incentives to build these flexibilities might pose a challenge. As pointed out in section 4.6.2, the average captured price on the energy only market is not sufficient to cover the cost of neither batteries nor P2G2P capacities or gas turbines up until 2050. The requirement for remuneration of supply-side flexibility beyond pure market-based utilisation could turn out to be a significant bottleneck towards building up the more than 10 GW of capacity required in 2050 (Figure 43). It is therefore necessary to monitor the existing incentives and adjust or complement them in case the required build-up is lagging. This topic is further explored in section 4.6.3.

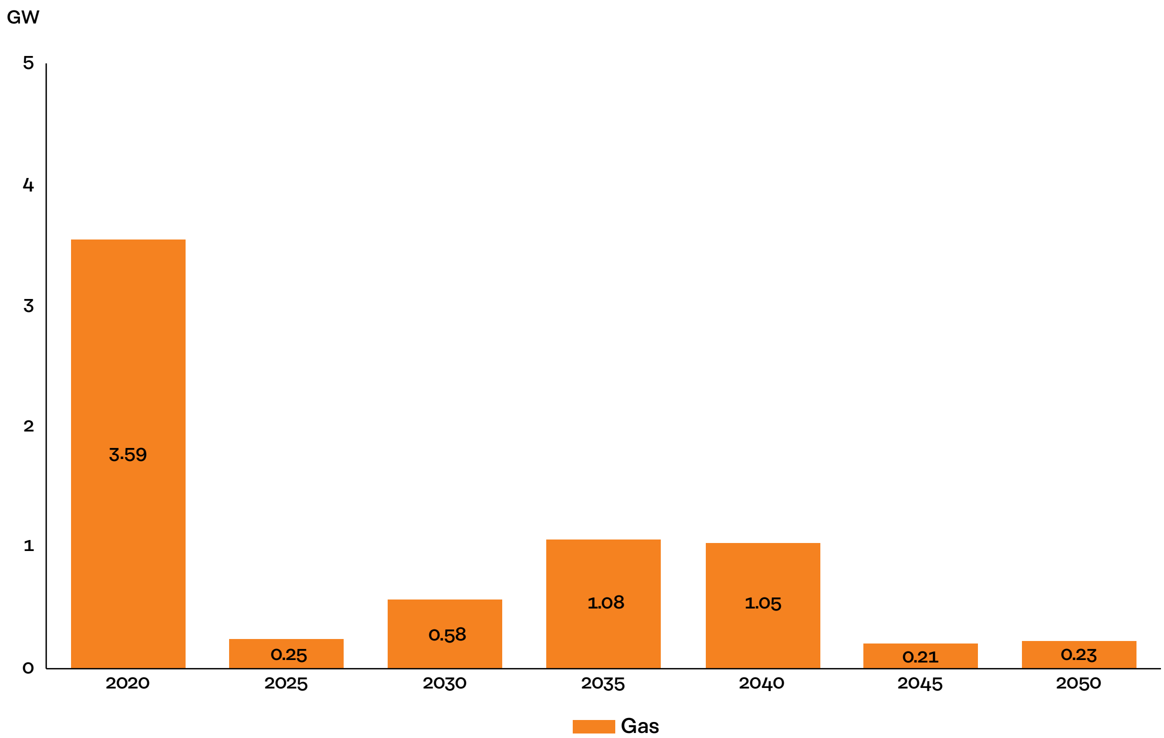
The revenue streams for batteries and seasonal storages might differ, however. Batteries could generate more steady revenues on the energy only markets, due to their higher activation rates. Moreover, batteries can offer a very fast responding increase in power output. They could therefore be utilised also in TSO's ancillary services markets (e.g. frequency containment reserve (FCR) and fast frequency reserve (FFR)) and offer local voltage control and

Figure 47: Evolution of gas fired generation capacities – Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

Figure 48: Evolution of gas fired generation – Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

improved reliability of supply in distribution networks. These additional uses could significantly improve their profitability and thereby reduce the need for remuneration complements. Ensuring the access to joint TSO and DSO flexibility markets is therefore a key measure to support the build-up of required battery capacities.

Besides investment incentives, additional bottlenecks for P2G2P capacities and gas-fired generation exist in the form of the currently limited Finnish gas grid and particularly storage infrastructure. The lack of storage could be relieved by increasing the interconnection of the Finnish gas grid to the rest of European (like e.g. the new pipeline to Estonia). Integrating a Finnish hydrogen infrastructure with the rest of Europe should also be explored.

Next steps recommendations for supply side flexibility

- Regularly review the sufficiency of investment incentives for supply side flexibilities and if necessary, explore options to improve these incentives.
- Explore necessary support for the build-up of hydrogen (storage) infrastructure supporting the build-up of P2G2P capacities required to balance intermittent wind generation
- Explore options for the (increased) interconnection of Finnish gas and future Finnish hydrogen infrastructure with the rest of Europe to further improve the availability of flexibility for the Finnish energy systems.
- Regularly review the accessibility of TSO's ancillary services markets for all types of supply-side flexibilities (particularly batteries of all types) and explore options for joint TSO and DSO flexibility markets

4.3 Cross-border exchanges: Finland will temporarily turn in to an electricity exporter in the 2030s but interconnection will be important for integrating renewable generation over the entire period up until 2050

Key takeaways

- The start-up of Olkiluoto 3 as well as the expansion of onshore wind generation and interconnection capacities will turn Finland into an electricity exporting country in the 2030s.
- Rising electricity demand and retiring nuclear capacities will turn Finland into an electricity importer again from 2040 onwards.
- Throughout the time period, flexibility from regional hydro (Norway and Sweden) and nuclear generation (Sweden) available to the Finnish System via interconnection capacities will play and important role in integrating Finnish wind generation.

4.3.1 Finland will temporarily turn into and electricity exporter in the 2030s

Continuous onshore wind expansion, the start-up of additional nuclear capacity (Olkiluoto 3) and additional interconnection capacities will temporarily turn Finland into a net exporter of electricity in the 2030s in the Direct Electrification Scenario. The annual net electricity import balances presented in Figure 49, clearly show the rapid decrease in net electricity import after 2020 and increase in net imports after 2040. In the

2040s, power demand in Finland continues to grow while parts of the Finnish nuclear capacities are retired. Consequently, Finland will turn into a net importer of electricity on an annual basis again. In the Increased PtX Scenario both the period where Finland is a net exporter is shorter (only before 2035) and the exported volumes are smaller.

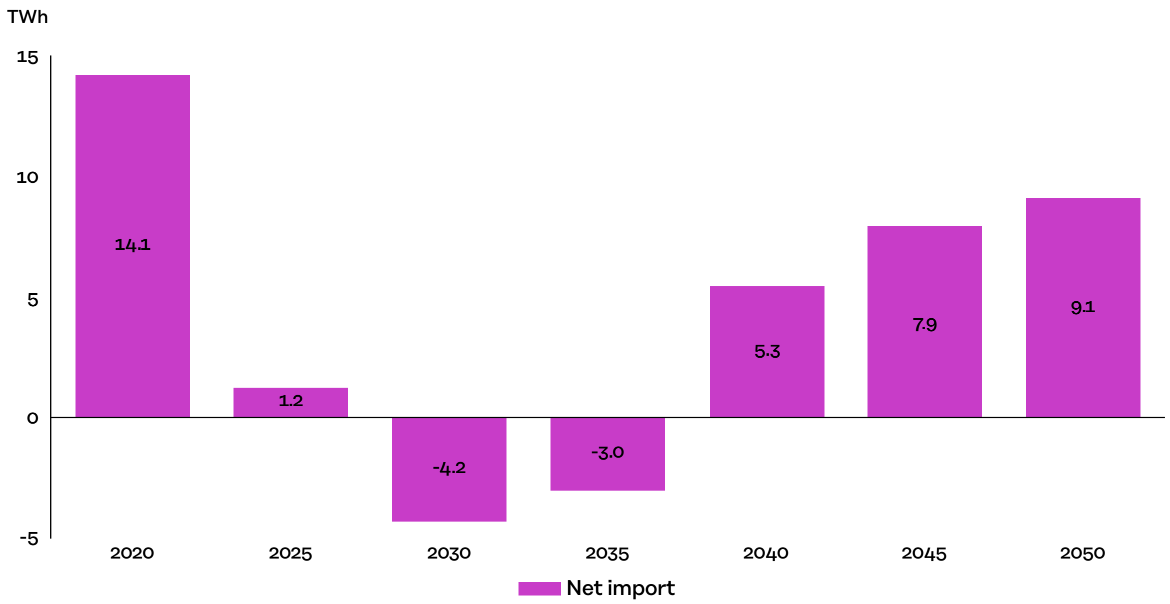
4.3.2 Interconnection capacities will provide the Finnish system with required flexibility

The continuous development of renewable energy sources across the Nordic region drives high utilisation of the interconnection capacity. Hydro capacity from Norway and Sweden will provide the required flexibility to balance increasing variable generation from (mainly) wind in the Nordic grid during the periods of low wind power generation.

In terms of the number of hours per year with net electricity imports, Finland would remain a net importer (more cumulative hours with net import than with net export) throughout the studied period except in 2030, as seen in for the Direct Electrification Scenario (Figure 50). Even during the period of annual net exports in the 2030s, Finland would import electricity over a large part of the year; only for some hours during the windy weeks would Finland be an actual exporter.

The large number of hours where Finland requires flexibility from regional hydro (Norway and Sweden) and nuclear (Sweden) generation highlights the importance of interconnection capacity in supporting the integration of Finnish onshore wind generation.

Figure 49: Finnish annual net electricity import balance [TWh/a], Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.3.3 Key bottlenecks and enablers for interconnection capacities

As we have highlighted, the expansion of interconnection capacities with neighbouring countries is critical. If the assumed interconnection capacities were much lower, this would require additional generation and flexibility in Finland. Planning and building these interconnections are long processes involving many stakeholders. To reach the scenarios described in this study, it is essential that these interconnection capacity expansions are secured.

Many of the same bottlenecks and enablers apply to both domestic transmission network and cross border interconnections. These bottlenecks are described in more detail in section 4.4.2. Potential challenges in interconnection projects have been identified as TSOs not reaching agreement in investment splitting and potentially long permitting processes (Makkonen, 2015).

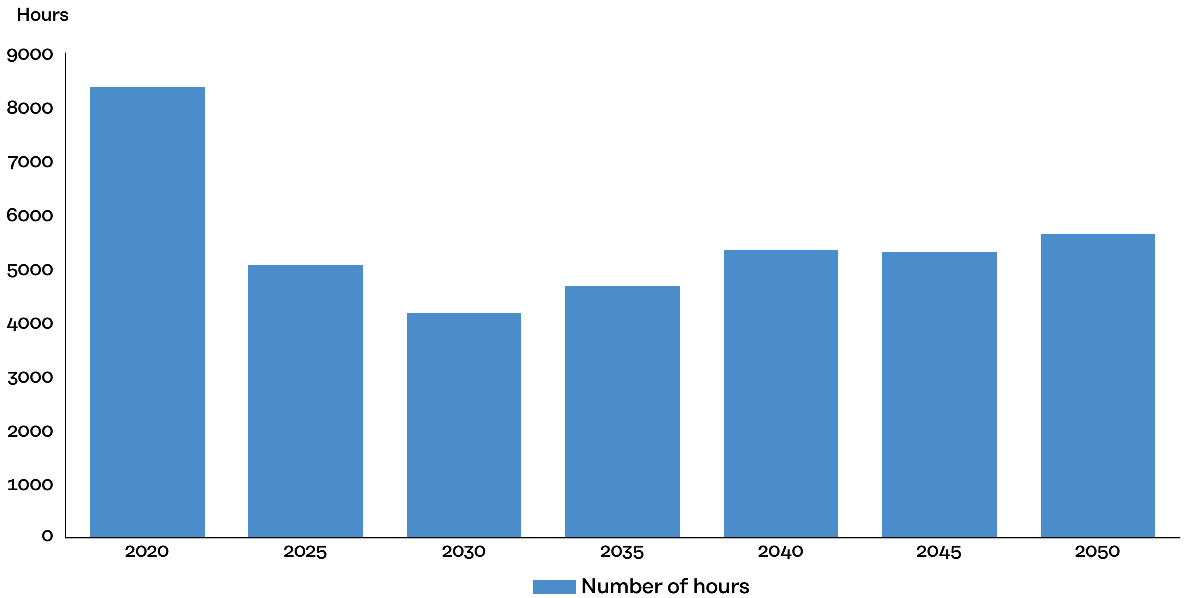
To support investments, EU funding can be acquired for projects that are in common interest of the entire EU, such as cross-border infrastructure.

To shorten the planning phase, it is important that all neighbouring TSOs continue their active communication to identify possible expansion needs early enough. This communication should also be active towards regulators.

Next steps recommendations for cross-border interconnections

- Provide political support for interconnection projects, for example by speeding-up permitting.
- Continue the active communication amongst neighbouring TSOs to identify needed expansions early enough and expand this active discussion towards regulators.

Figure 50: Number of hours per year with net electricity imports, Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.4 Electricity grids: Electrification will require significant expansion of the transmission but only limited expansion of the distribution network

Key takeaways

- Strong electrification will mainly impact the transmission network, increasing the need for transmission capacity expansion.
- Distribution networks need only limited capacity expansion, but peak demand management will become essential.

In this section, the effects of electrification are covered from the perspective of transmission and distribution networks.

4.4.1 Effects of electrification on the transmission network

Electrification will have major effects on the transmission network as the annual consumption of electricity in Finland doubles by 2050 and transmission capacity demand increases multiple times. Due to their high-power requirements a significant share of new loads resulting from widespread electrification (e.g. electric arc furnaces and electrolysers) are generally connected directly to the transmission network. In both decarbonisation scenarios, generation capacity is expected to double in the next 15 years, which sets a very fast expansion demand for the transmission network. Under the Increased PtX Scenario, these effects would be more pronounced until 2050 due to even higher electricity demand and generation.

4.4.2 Key bottlenecks and enablers for transmission network

Transmission lines cover very long distances and cross the land areas of many landowners and municipalities, causing permitting and planning to take a long time. The question of how the design and planning process could be streamlined and quickened should be explored in more detail (e.g. building on the experience of reservations for transmission lines in regional zoning). Also, the streamlining of Environmental impact assessment (EIA) should be explored e.g. by handling different sections of the assessment in parallel or in cases of two transmission lines built side by side. By identifying potential expansion needs as early as possible in cooperation with relevant stakeholders, it could be ensured that needed capacities are ready when they are needed. This early identification has already partly been done by Fingrid (2021) and could be further enhanced by regularly updating the industrial carbon neutral roadmaps.

As the demand for new transmission lines increases new technologies might be needed. The capacity of existing transmission lines could be slightly increased by utilising dynamic load monitoring and local flexibility. Local flexibility could be enabled by having location information with the flexibility bid. To reduce the required number of transmission lines (improving public acceptability) increased voltage level or high voltage direct current (HVDC) technologies could be utilised to reduce losses and increase power transfer capacity.

As far as possible, moving demand closer to generation would reduce electricity transmission needs. An interesting case could be to move part of the power-to-x production near wind farms and utilising the gas network to transfer the energy. Spatial optimisation of the energy system (also accounting for waste heat produced by electrolysers that might be useful in urban areas) and collaboration in planning of the gas and electricity grids would be supportive for achieving an energy carrier mix fulfilling both cost and acceptability considerations.

Beyond the capacity expansion of domestic transmission network, future expansion of interconnections with the neighbouring countries is critical. If the assumed interconnection capacities described in section 4.3 were much lower this would require additional generation and flexibility in Finland. Planning and building these interconnections are long processes involving many stakeholders. To reach the described scenarios detailed in this study, it is essential that these interconnection capacity expansions are secured.

The traditional kinetic inertia of the power system is decreasing, as rotating generators are no longer directly connected to the anymore. With low inertia, the power system's capability to maintain steady frequency is reduced. Synthetic inertia is one of the options to replace lowered kinetic inertia. For example, battery energy storage systems in data centres can provide very fast responding flexibility (Alaperä, 2019). In addition, inverter-connected wind turbines have the potential to utilise the rotating kinetic energy of the blades into short additional turbine output (Fairley, 2016). The needs and availability of inertia should be reviewed and projected regularly, and possible challenges identified early on.

Next steps recommendations for transmission network

- Explore streamlining the permitting process of transmission lines to ensure, that transmission capacity will not limit the uptake of energy intensive industry and new generation.
- Expand existing approaches for the early detection of connection expansion needs and respective grid upgrade requirements to be fed in network planning and permitting processes.
- Explore the need to support new electricity transmission technologies e.g. regarding permitting
- Assess the optimal spatial layout of the energy system considering alternative energy carriers
- Integrate the network development planning for electricity, gas and hydrogen

4.4.3 Electrification impacts on distribution grids

In distribution networks the electrification of demand is mostly reflected by increasing numbers of EVs (EV), heat pumps (HP), and (often behind the meter) solar photovoltaics (PV). The two developed scenarios do not differ significantly in these aspects.

Challenges to distribution grids coming from increased electrification have been case studied by Lassila et al. (2019), Haakana et al. (2018), and Belonogova et al. (2020). The impacts of EVs, HPs, and PVs were studied in rural and urban Finnish networks. Results from these case studies have been used in this section to map the potential challenges of future distribution networks. It can be generally concluded that electrification will not cause major issues for distribution networks.

The aforementioned case studies point out that PV and HP systems lead to decreased annual energy demand and decreased peak power in the studied case networks. It is also clear that EVs increase the annual electricity demand and lead to significant increase in peak power in the case networks. The increased peak power caused by EVs increases the overall peak power in the network, despite PV and HP systems. EVs, however, also offer a significant source of flexibility for the power system.

4.4.4 Key bottlenecks and enablers for distribution networks

Increased peak power sets challenges in the form of capacity constraints and potential voltage quality issues. A potential challenge can arise in a small share of distribution transformers and low voltage conductors. These are at risk of becoming overloaded, if no flexibility is applied to EV charging in particular. So smart charging will be important to enable a high penetration rate of EVs not only from a system wide but also from a DSO-perspective. It is expected that large-scale deployment of intelligent solutions for demand side response, such as smart EV charging, will be applied to avoid congestions in distribution network. A power-based tariff component could be a potential solution to incentivise the flexible charging of EVs. Other solutions to reduce peak power include utilising demand response, battery energy storage systems (BESS), and more optimised dimensioning of heat pumps.

Using BESS would also support voltage control as would the increased use of inverter-based generation, such as PV by locally producing reactive power (Fairley, 2016). In order to improve DSO's access to BESS based flexibility, possibility of having integrated TSO and DSO flexibility markets could be explored. This market should also include bids with location data to improve the locality of flexibility services.

Next steps recommendations for distribution networks

- Explore the implementation of power-based components in the network tariff for households to incentivise peak power reductions e.g. to incentivise smart EV charging
- Explore how to increase the TSO and DSO interaction regarding flexibility markets

4.5 Power System Investment: Electrification based decarbonisation by 2050 will require significant electricity system investments

Key takeaways

- Building up Finnish **generation and electricity storage capacities** in line with the results for the cost-optimal generation mix would require investments until 2050 of about 64 billion $€_{2020}$ in the Direct Electrification Scenario and about 70 billion $€_{2020}$ in the Increased PtX Scenario (both undiscounted sums); the by far biggest share of investment (almost 70%) in both scenarios is thereby directed towards onshore wind capacity expansion.
- Based on Fingrid scenarios, investment in the **domestic transmission network** required to accommodate additional demand and generation in line with the two scenarios (i.e. beyond Fingrid's current 2 billion $€_{2020}$ plan) were estimated to be between 1.5 and 3 billion $€_{2020}$ up until 2050 (undiscounted sums).
- Besides, additional investment of about 0.9 billion $€_{2020}$ for the years 2020–2035 and about 2.6 billion $€_{2020}$ for the years 2035–2050 (undiscounted sums) would be required for the expansion of **interconnection capacities** in line with the scenario assumptions.
- Large scale electrification is not expected to require **distribution grid investments** as capacity expansions would generally be covered by regularly required renewal and upgrade investments.

This section presents the investments (CAPEX) in power generation, storage, transmission, and distribution required up until 2050 to implement the wide-spread electrification charted by the two decarbonisation scenarios.

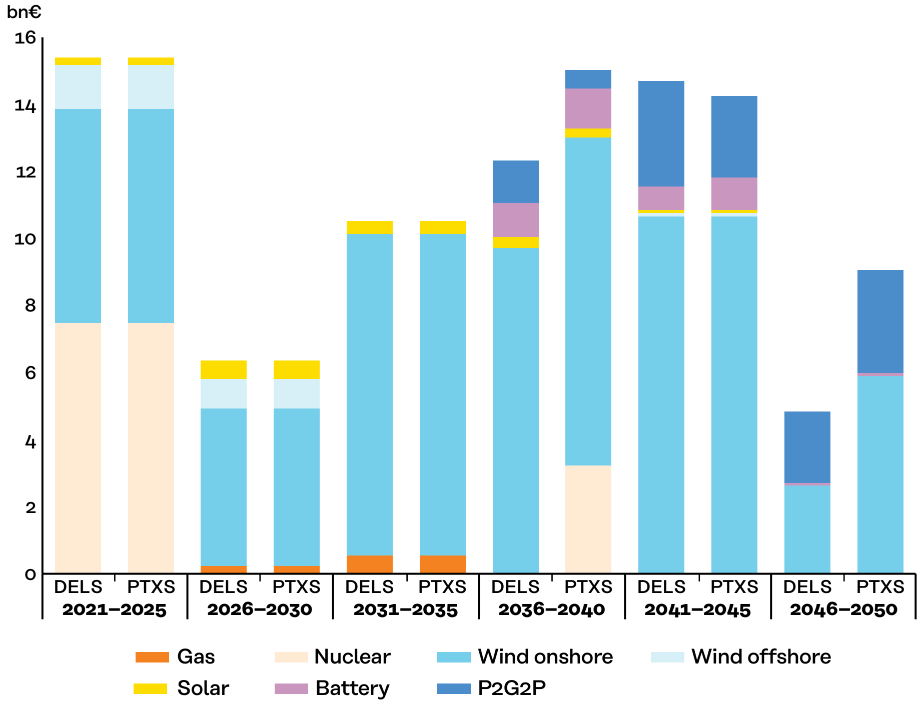
4.5.1 Generation & storage investment: Both scenarios require significant investments in generation and storage capacities

Both analysed scenarios require a **significant expansion of generation and storage capacities** until 2050. When evaluating investment needs the cost reduction assumptions outlined in section 4.1.1 were applied to the determined capacity expansion requirements.[3]

Figure 51 shows the resulting capital expenditures (CAPEX) summed-up (non-discounted) per technology over five-year periods. Investments follow similar trajectory in both scenarios in the short-term, but the total CAPEX investments in the Increased PtX Scenario (total of 70 billion $€_{2020}$ between 2021-2050) exceed those of the Direct Electrification Scenario (total of 64 billion $€_{2020}$ between 2021-2050) by 2050. The differences result from the additional capacities needed to meet the increased demand in the Increased PtX Scenario. In line with the capacity expansion needs outlined in section 4.1.3 the biggest share of investments (almost 70%) will be needed to build-up onshore wind generation capacities followed by longer-term storage and nuclear capacities.

3 Required investments in gas or hydrogen infrastructure (including storage) where not considered.

Figure 51: CAPEX per technology (bn€$_{2020}$, non-discounted sums), Direct Electrification (DELS) and Increased PtX (PTXS) Scenarios



Note: Investment into nuclear capacity in 2021-2025 represents Olkiluoto 3 and the timing is matched with the expected start of commercial operation (i.e. 2022)
Source: CL power dispatch model results by Compass Lexecon

4.5.2 Transmission grid investment: Fingrid estimates significant investment needs in the transmission grid to allow for the widespread electrification underlying the two scenarios of this study

Fingrid (2021) has analysed future challenges and investment needs of the transmission network in their study *Verkkovisio*. The study focuses on effects of increasing wind power and strongly increasing electricity demand in four different scenarios until 2045. The results from the *Verkkovisio* study are used to estimate investment needs in **the domestic transmission network** required for the two scenarios developed in this study.

Northern Ostrobothnia and Lapland have high wind potential while a large part of the Finnish population and most of the electricity demand is in southern parts of Finland. Electrification therefore puts pressure on north-south transmission capacities, further amplified by increasing electricity imports from Northern-Sweden. Consequently, the biggest share of transmission network investments result from increasing north-south transmission capacities. Additional investments are needed on the west coast and the eastern border – generally to connect wind farms.

Concerning electricity demand and electricity generation, the two scenarios presented in this study fall in-between Fingrid's *Sähköä Vientiin* and *Ilmastoneutraali Kasvu* scenario. The estimated 2045 electricity demand and wind power generation in the *Ilmastoneutraali Kasvu* scenario are higher than the respective 2050 figures in the Increased PtX Scenario.

For 2021–2030, Fingrid has already planned network renewals and upgrades for a total of 2 billion €$_{2020}$. Fingrid has analysed additional domestic network investments based on their own scenarios. Depending on the scenario, estimated north-south capacity demand in 2035 is 10–14 GW and in 2045 about 14–29 GW. Based on the capacity demand in 2035, the total resulting additional investments to 2035 in Fingrid's study range from 0.75 billion to 1.5 billion $€_{2020}$.

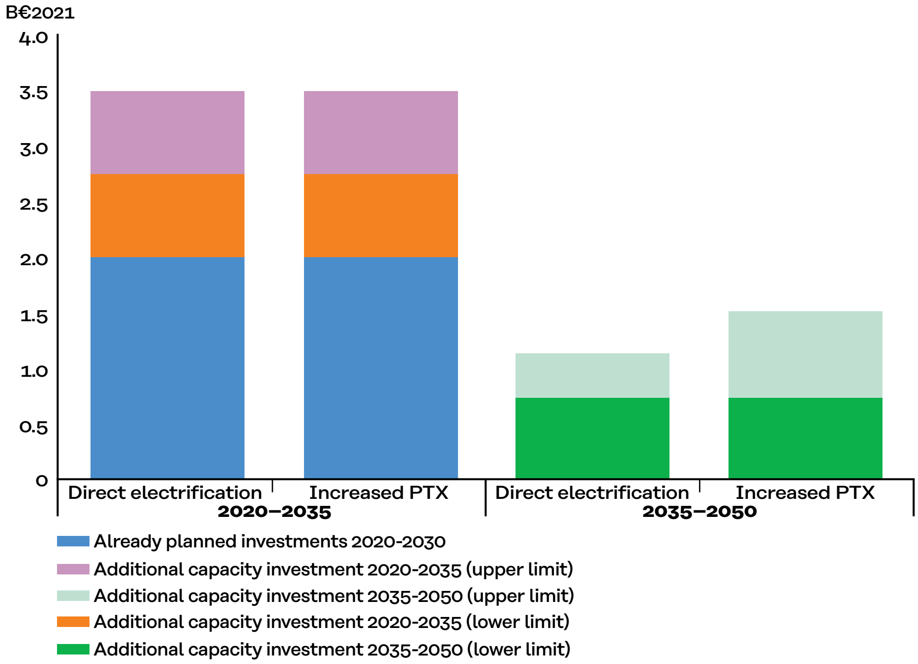
The two scenarios in this study have relatively similar demand increases until 2035, leading to the expectation of similar investment demands. They are, moreover, within the assumptions of the Fingrid scenarios. For the period to 2035, the additional investments (CAPEX) in the domestic transmission network (i.e. going beyond Fingrid's current 2 billion $€_{2020}$ plan) for the two scenarios presented in this study are therefore estimated to be similar to the results presented in the Fingrid study – i.e. in the range of 0.75 billion to 1.5 billion $€_{2020}$.

Post 2035, the biggest differences in transmission demand between the two scenarios of this study are in 2045–2050. Wind generation and electricity demand expand significantly in the Increased PtX Scenario compared to the Direct Electrification Scenario. It can be estimated, that without some form of additional flexibility or other means of transporting the added electricity demand, the Increased PtX Scenario would have slightly higher transmission capacity demand and thus also higher investment needs.

By comparing the expected increase in transmission capacity demand up until and following 2035 in the Increased PtX Scenario with the assumptions of the Fingrid study, it was assumed that the investment need in 2035–2050 would be at the same order of magnitude – i.e. also in the range of 0.75 billion to 1.5 billion $€_{2020}$. From this comparison, however, lower investment needs were deducted for the Direct electrification scenario.

Based on this analysis the total additional **investment** (going beyond Fingrid's current 2 billion $€_{2020}$ plan) **in domestic transmission networks for the two scenarios is estimated to be in the range of 1.5 to 3 billion $€_{2020}$** (undiscounted sums) **up until 2050** (Figure 52).

Figure 52: Future investment needs to domestic transmission network (CAPEX). Included are uncertainties in the investment amounts.



Source: LUT analysis based on Fingrid (2021).

4.5.3 Interconnection investments: The expansion of interconnection capacity also requires significant investments – particularly post 2035

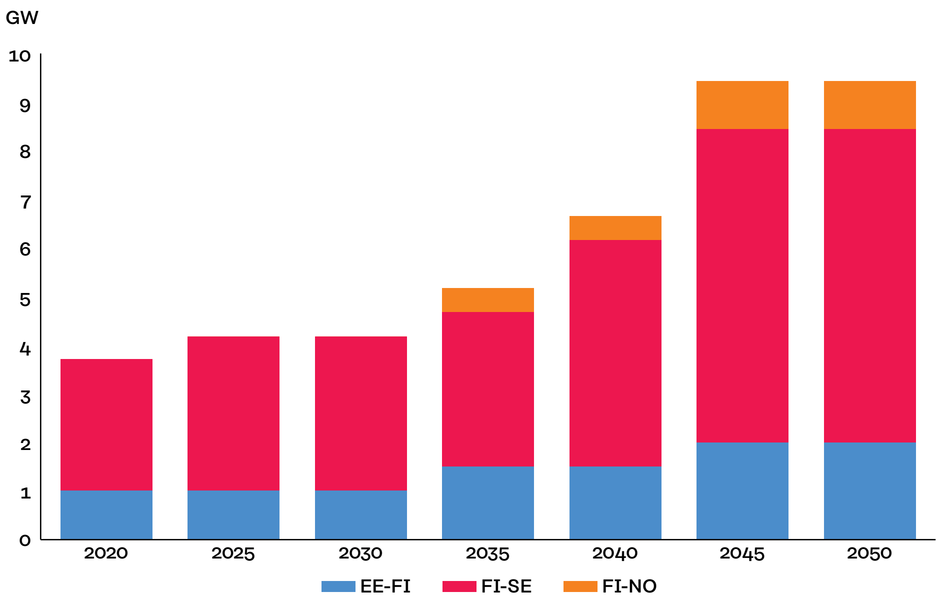
In addition to investments in the domestic transmission network, **investments in interconnection capacities to neighbouring countries** are required to arrive at the values assumed in the scenario definitions (section 4.1.1 and Figure 53). Cross border capacities are assumed to increase by 1.5 GW by 2035 and 5.8 GW by 2050 from the 2020 capacity level.

Investment needs were assessed based on the study by Svenska Kraftnät, Fingrid, (2019) on the cost of HVDC interconnections between Finland and Sweden. The specific investments (€/MW) from this aforementioned study were used to assess investment needs for future HVDC interconnection to Sweden, Norway, and Estonia. In the current study, **the total investments in interconnections would be about 0.9 billion €$_{2020}$ for 2020–2035 and about 2.6 billion €$_{2020}$ for 2035–2050**. It has to be noted, however, that investments in cross-border capacities are typically shared among the adjacent TSOs.

4.5.4 Distribution investment: Large scale electrification is not expected to require distribution grid investments as capacity expansions would generally be covered by regularly required renewal and upgrade investment

Near future investment demand in Finnish electricity distribution infrastructure was studied by Partanen (2018), among others. Investment demand is mainly driven by renewal of ageing network infrastructure (including transformers, conductors, poles). This investment demand is estimated to be about 6.6 billion €$_{2020}$ in 2016–2028. Addi-

Figure 53: Cross-border transmission capacity assumptions [GW]



Source: Compass Lexecon, based on Ten-Year Network Development Plan (TYNDP) (ENTSO-E, 2021) tional investment demand comes from new regulation regarding the security of supply in distribution networks. The regulation sets time limits for customer interruptions to 6 hours in urban areas and to 36 hours in rural areas. This new regulation must be fulfilled by 2028, excluding few network operators. Estimated required investments represent an additional 3.1 billion $€_{2020}$ by 2028. (Partanen, 2018.)

The average techno-economic lifetime of network components is usually about 40 years. When distribution companies are designing their upcoming network updates, they should already consider upcoming effects of distributed energy resources (DER) and new loads in their network. This way they can include potential capacity upgrades in their already mandatory investments and reduce the need to make additional investments to the capacity in future. As we saw in section 4.4.3, some distribution transformers and conductors might need upgrading to handle increased peak power. In near future, when utilities upgrade their ageing network, they will most likely also upgrade these smaller transformers to larger ones, mostly to improve short circuit current and voltage quality – but also significantly reducing capacity constraints. The same can be done for the conductors, as overhead power lines are replaced with underground cables to improve security of supply. Overall, it can be concluded, that no major investments beyond the planned renewal and upgrade of ageing network equipment estimated at 9.7 billion $€_{2020}$ (LUT analysis, based on Partanen (2018)) would be required. It can be estimated that these investments are done by 2035.

4.6 Electricity cost: Electricity production costs (LCOE) decline, rising wholesale prices are not sufficient to incentivise all required investments, and end-users are largely shielded from higher energy costs

Key takeaways

- In both scenarios overall electricity production costs in Finland (LCOE) would decline by almost 30% in 2050 compared to today. When factoring in imports, cost of electricity consumed in Finland in 2050 still declines by 20% compared to today.
- Higher intermitted renewable penetration will change the wholesale power price dynamics compared to today, increasing the number of hours with high but also low to zero prices.
- Captured revenues from day-ahead electricity market are insufficient for storage and peaking technologies (batteries, P2G2P, new OCGT) to build economically viable capacity even in 2050.
- From an end-user perspective, increased usage of electricity – and associated costs – are balanced with a steep decline in fossil fuel usage and imports.

This section first presents the relative (LCOE) and absolute power system costs for the two scenarios, relates the electricity production costs (LCOE) to the wholesale power prices, and then outlines remuneration incentives for different technologies. The section ends with a presentation of energy costs from an end-user (industry and households) perspectives.

4.6.1 Electricity production cost: Overall electricity production costs (LCOE) decline by a third up until 2050

Power system costs, which here refer to the cost of power generation and storage[4] (without the cost of networks) consist of the following four cost components:

- Annualised **CAPEX**[5], represents the annualised capital expenditures of all capacities present in a given year (i.e. new as well as invested in earlier years but still operational);
- Annual **fixed operation and maintenance** (FOM) **costs;**
- Annual **variable operation and maintenance** (VOM) **costs;** and
- Annual **fuel-costs** if applicable; omitting CO_2 costs but including the cost of energy (pumping, charging) for storage technologies, i.e. losses during storage operations.

The power system cost results for the two scenarios, presented in real $€_{2020}$ terms are shown in Table 9 (DELS) and Table 10 (PTXS).

Table 9: Power System costs, Direct Electrification Scenario

Annualised power system cost (bn$€_{2020}$/y)	2025	2030	2035	2040	2045	2050
Annualised CAPEX	3.56	3.85	4.46	4.46	5.06	4.71
Annual FOM Cost	1.26	1.25	1.47	1.55	1.66	1.75
Annual VOM Cost	0.25	0.27	0.22	0.16	0.18	0.21
Annual Fuel Cost	0.51	0.52	0.46	0.41	0.41	0.46
Sum of Annualised Costs (excl. commercial balance*)	5.58	5.90	6.61	6.58	7.32	7.14
Sum of Annualised Costs (including commercial balance*)	5.70	5.92	6.96	7.75	8.82	8.48
LCOE ($€_{2020}$/y/MWh)	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Sum of the Annualised costs per MWh generated in Finland (excl. commercial balance*)	61.6	56.5	53.7	48.0	47.7	44.8
Sum of the Annualised costs per MWh consumed in Finland (including commercial balance*)	62.0	59.3	58.3	55.0	56.2	52.1

Notes: * Commercial balance is the value or cost of net imports or net exports.
Source: CL power dispatch model results by Compass Lexecon

4 Storages refer to batteries (short-term storage) and P2G2P (long-term storage). For P2G2P the cost of gas/hydrogen infrastructure are not included.
5 Note that the annualised CAPEX reported in 5-year intervals (2025, 2030, etc.) reflects all new capacities built during the 5-year periods (2021-2025, 2026-2030, etc.) as well as the capacities built previously and still in operation.

Table 10: Power System costs, Increased PtX Scenario

Annualised power system cost (bn€$_{2020}$/y)	2025	2030	2035	2040	2045	2050
Annualised CAPEX	3.56	3.85	4.46	4.62	5.21	5.13
Annual FOM Cost	1.26	1.25	1.48	1.60	1.70	1.88
Annual VOM Cost	0.25	0.28	0.25	0.24	0.23	0.26
Annual Fuel Cost	0.51	0.53	0.50	0.48	0.45	0.47
Sum of Annualised Costs (excl. commercial balance*)	5.58	5.91	6.69	6.93	7.59	7.75
Sum of Annualised Costs (including commercial balance*)	5.71	5.98	7.43	8.62	9.92	9.53
LCOE (€$_{2020}$/y/MWh)	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Sum of the Annualised costs per MWh generated in Finland (excl. commercial balance*)	61.6	56.5	52.9	48.0	47.4	44.4
Sum of the Annualised costs per MWh consumed in Finland (including commercial balance*)	62.0	58.9	56.7	54.9	56.4	52.1

Notes: * Commercial balance is the value or cost of net imports or net exports.
Source: CL power dispatch model results by Compass Lexecon

While it is interesting to observe the slightly increasing trend in annualised CAPEX and FOM costs over the studied period, the split of these fixed costs by technology provides us with further insights, as shown in Figure 54 for both scenarios. In the 10 years up to 2030 these costs are almost equally dominated by nuclear and onshore wind technologies. From 2035 onwards, however, onshore wind dominates annualised CAPEX and FOM expenditures.

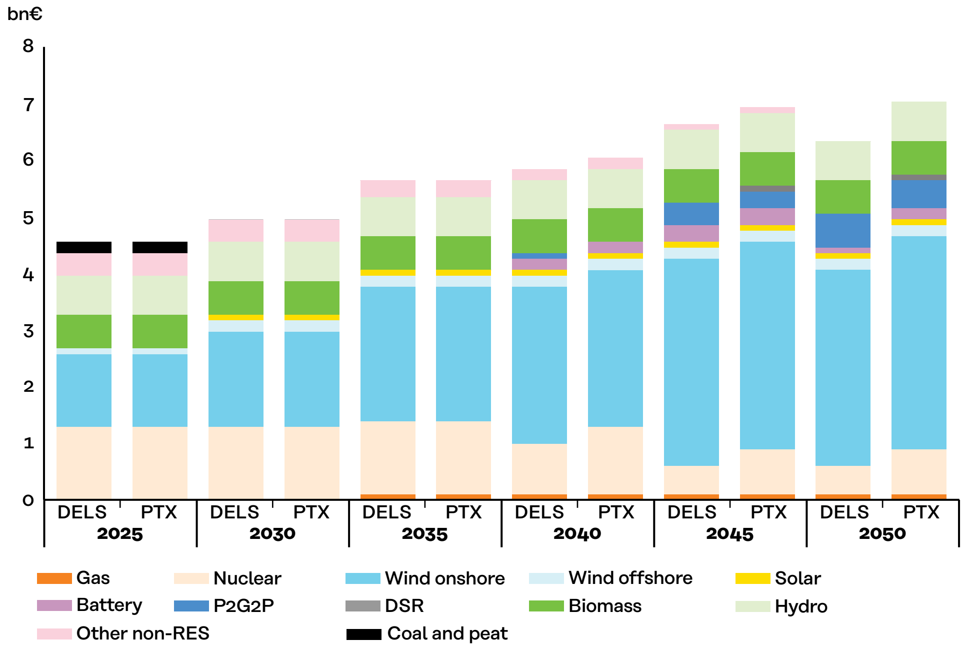
The variable costs (i.e. fuel and VOM costs) shown in Figure 55 are low throughout the entire period as the Finnish generation mix is made up predominantly of technologies with low variable cost (wind and nuclear).

Table 9 and Table 10 also show two additional cost measures: 1. **sum of annualised costs**, and 2. **sum of annualised costs per MWh**. The first measure sums all the annualised costs in a given year and gives the total costs for electricity generation and storage.[6] The second measure relates the summed annualised costs to power generation (or consumption, explained below) in Finland giving a relative cost measure. Before interpreting these key comparative cost measures, two important and interrelated points need to be explained.

The first is that despite the fact that the customer (net) load is the same in each scenario and its sensitivities[7] the power generated in Finland (structure and level) meeting this demand is different in every scenario and sensitivity. The second point is that not only the Finnish generation is different due to the difference in scenario or sensitivity, but also the level of cross-border power imports and exports differs. To highlight the point on differing imports and exports (which have an impact on the power system costs) between the scenarios, see Table 11 (DELS) and Table 12 (PTXS). The key difference is that in DELS the import volumes are systematically lower from 2035 onwards while exports are approximately

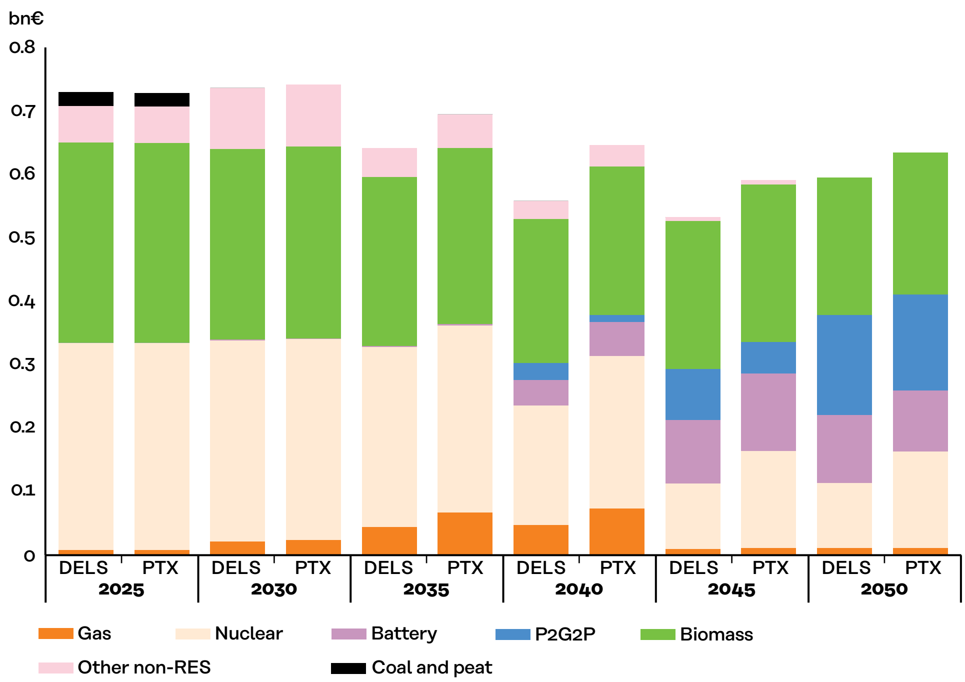
6 Excluding costs for gas or hydrogen infrastructure.
7 There are, however, differencs between the two scenarios mainly due to the demand of electrolysers producing PtX fuels more than offsetting reduced direct electrification demand.

Figure 54: Annualised CAPEX and FOM Costs per technology (bn€$_{2020}$/y), Direct Electrification and Increased PtX scenarios



Notes: DSR refers to Demand Side Response. The DSR costs are shown for the following load shedding DSR types (requiring additional investment) as defined in the section on demand side flexibility: DSR of last resort, DSR of direct electrification of industry, and DSR of industrial hydrogen production. Embedded DSR flexibility from EVs and heat pumps is assumed to be delivered at no cost via time of use (TOU) tariffs.
Source: CL power dispatch model results by Compass Lexecon

Figure 55: VOM and Fuel Costs per technology (bn€$_{2020}$/y), Direct Electrification and Increased PtX scenarios



Source: CL power dispatch model results by Compass Lexecon

Table 11: Volume and value of imports and exports in the Direct Electrification Scenario

	2025	2030	2035	2040	2045	2050
Imports (TWh)	13	11	16	25	34	35
Imports Value per MWh imported (€/MWh)	41	51	63	73	76	72
Exports (TWh)	12	15	19	20	27	26
Exports Value per MWh exported (€/MWh)	35	36	35	34	42	45

Table 12: Volume and value of imports and exports in the Increased PtX Scenario

	2025	2030	2035	2040	2045	2050
Imports (TWh)	13	11	20	30	41	39
Imports Value per MWh imported (€/MWh)	40	52	66	77	81	74
Exports (TWh)	11	15	15	17	22	24
Exports Value per MWh exported (€/MWh)	34	36	38	36	42	45

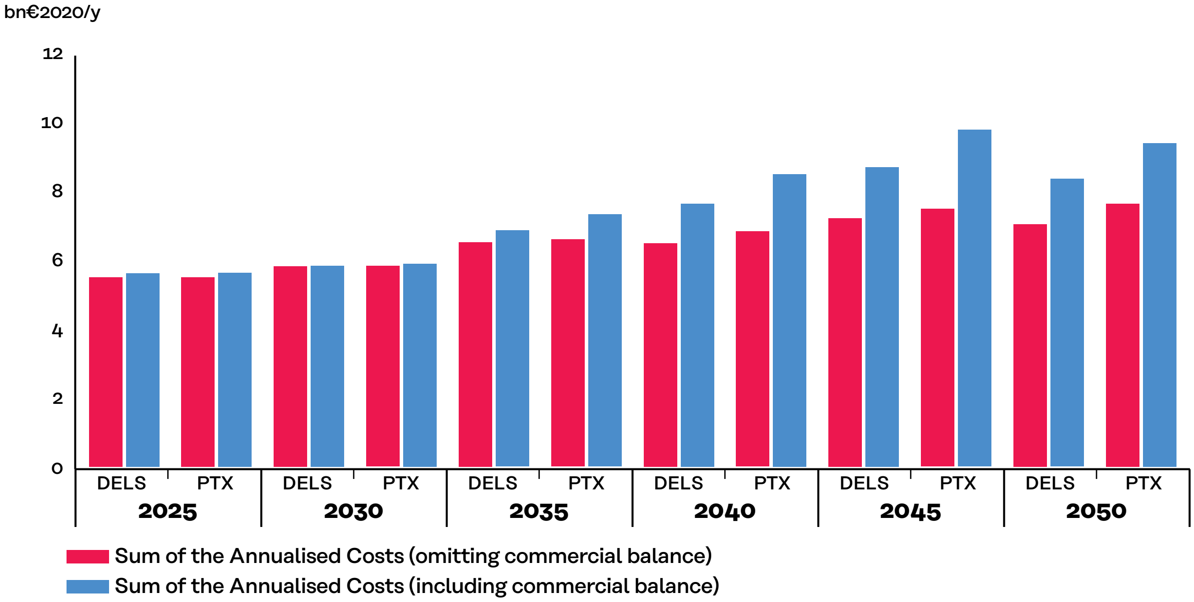
equal between the scenarios. This means that imports are more relied on in PTXS to meet the higher demand. The average values of imports show that Finland imports in high demand periods (higher €/MWh and increasing over time) and exports in periods of supply surplus (lower €/MWh implies exporting excess wind generation during its regional abundance).

Because the volume and value of imports and exports differ in the two scenarios, we should consider their impact on power system costs. For this reason, Table 9 and Table 10 also show, in addition to the sum of the annualised costs, and **sum of the annualised costs per MWh,** their modified versions reflecting the **value (cost) of commercial balances.** Commercial balances mean that the value or cost of net exports or net imports priced at the Finnish day-ahead spot prices are added to the power system costs. When including the value of commercial balances, the costs of imports (Finland is mostly a net importer) are included, which makes the comparison of power system costs between scenarios with very different import volumes more representative.

The first comparative cost measure, **sum of the annualised costs**, is shown in Figure 56 for both scenarios with and without the commercial balances. This absolute cost measure shows that in the short term until 2030 the costs are similar between the scenarios and the impact (costs) of commercial balances is relatively small. From 2035 onwards – when the demand starts growing and more so in the PTXS – the PTXS scenario becomes systematically more expensive mainly due to the needed higher CAPEX investments. Without the commercial balances, the absolute difference between the scenarios varies between 10 to over 600 million $€_{2020}$/year. The impact of commercial balances on the absolute power system costs becomes clear especially in the PTXS scenario, which can be up to 30% higher (2045) compared to costs omitting the commercial balances.

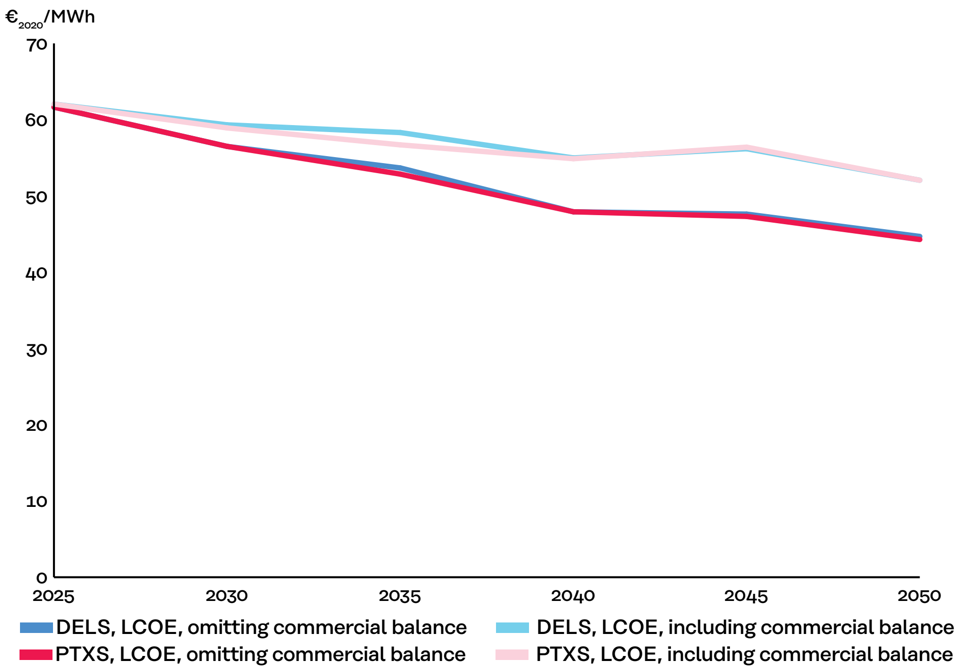
The second comparative cost measure is a relative measure comparing the sum of annualised costs in a given year to the total MWh generated in Finland. This cost measure is called the **Levelized Cost of Electricity (LCOE)**, expressed in $€_{2020}$/year/MWh. The LCOE measures the lifetime costs of energy generating assets in relation to (ratio of) the total electricity these assets generate over the assumed lifetime. It can be understood as the average total cost of building and operating the generating assets per unit of total electricity generated over the assumed lifetime. The LCOE's key benefit is its ability to **compare the electricity production costs across scenarios (sensitivities) on a MWh basis** allowing comparison between different

Figure 56: Total power system cost (absolute), Sum of the annualised costs [bn€$_{2020}$/y]



Notes: * Commercial balance is the value or cost of net imports or net exports.
Source: CL power dispatch model results by Compass Lexecon

Figure 57: Total power system cost (relative) per MWh, LCOE, [€$_{2020}$/MWh/year]



Notes: COE refers to levelized cost of electricity. Commercial balance is the value or cost of net imports or net exports.
Source: CL power dispatch model results by Compass Lexecon

technologies (technological mixes) with unequal life spans, capital costs, and capacities.

The value of commercial balances (imports & exports) should be considered also in the LCOE measure for the same reasons as mentioned above, i.e. a smaller local power generation system heavily dependent on "costless" imports would not provide the full picture of the total power system costs. Figure 57 presents LCOE with and without commercial balances for the two scenarios.

Two key points can be observed in Figure 57. First, note that LCOE values are declining in all the shown trajectories. In the DELS scenario **the LCOE drops by 27% (without commercial balances) and by 19% (with commercial balances) between 2025 and 2050.** In the PTXS scenario LCOE drops by 28% (without commercial balances) and by 19% (with commercial balances) between 2025 and 2050. The **reduction in the LCOE is** explained mainly by ever more dominant **wind generation** having **generation cost below** the **current generation mix** and assumed **cost decreases for onshore wind**. Modest increase in the total annualised system costs in all scenarios (and sensitivities) are therefore driven down by significant annual increases in power generation.

Second, the impact of commercial balances on LCOE is increasing over time, having only a minor (1% increase) impact in 2025 but 13-17% impact (increase) from 2040 onwards, depending on the scenario and year. This shows that including the cost of commercial balances reduces slightly the declining trend of LCOE, but nonetheless the relative €/MWh costs still decline by almost 1/5 from 2025 to 2050 in both scenarios. Importantly, the LCOE relative costs for both scenarios follow a very similar path throughout the entire studied period.

In sum, the power system costs are lower in the DELS scenario in absolute (because DELS power system is smaller than PTXS while still being more than 3x larger than now), but on relative MWh basis (LCOE) the two scenarios carry similar costs.

4.6.2 Electricity wholesale prices: Higher intermittent renewable penetration will change the wholesale power price dynamics

This section discusses the fundamental drivers of the resulting wholesale power prices and contrasts them with the LCOE costs. Understanding the differences between power prices and the LCOE costs is necessary because the intuition of increasing wholesale prices (when the system has ever more increasing shares of low or zero marginal cost generation) and decreasing the LCOE is not self-evident.

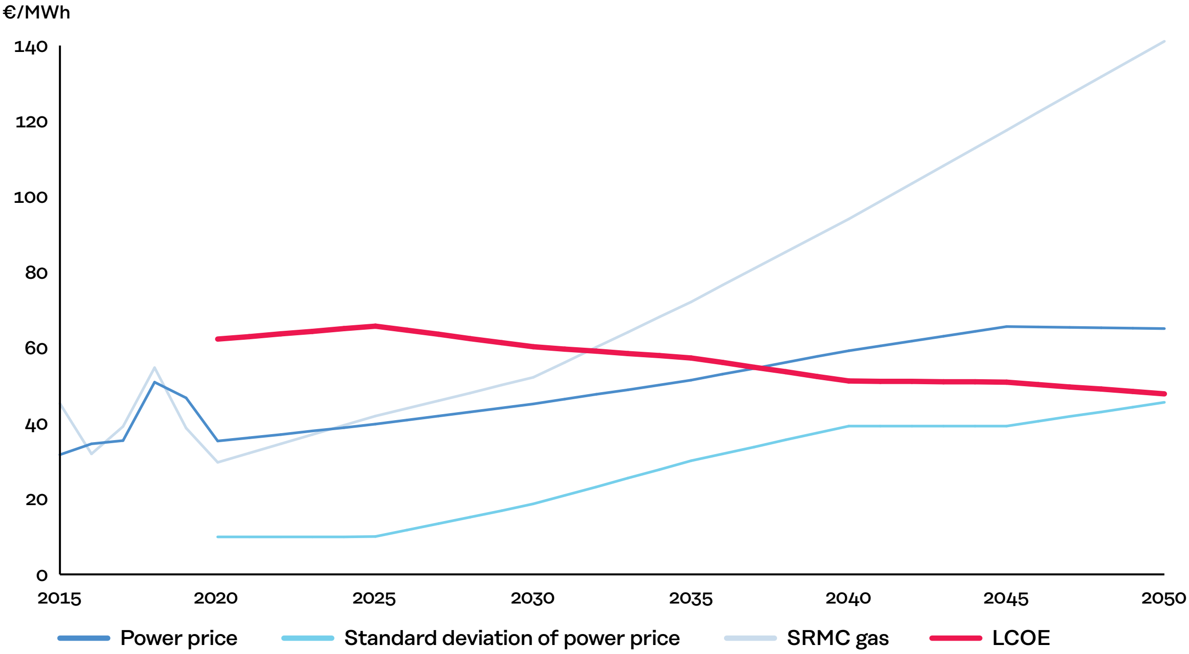
There are two important differences between the LCOE and the average wholesale power prices that explain the diverging price (cost) trajectories:

— First, the LCOE does not include the cost of CO_2 (see Appendix B.2 for detailed assumptions on CO_2 prices), which power prices do, because taxes are not considered as costs to the power system but are understood as a redistributive mechanism. The CO_2 costs are reflected in the power prices either explicitly (thermal unit sets the marginal price) or implicitly (non-thermal unit sets the marginal price by following a bidding strategy of a gas peaking unit based on its short-run marginal costs (SRMC)).

— Second, the LCOE here represents the average cost of building and operating all power generating assets over their lifetime, whereas the power prices reflect average marginal costs of the most expensive units needing to satisfy demand in every hour.

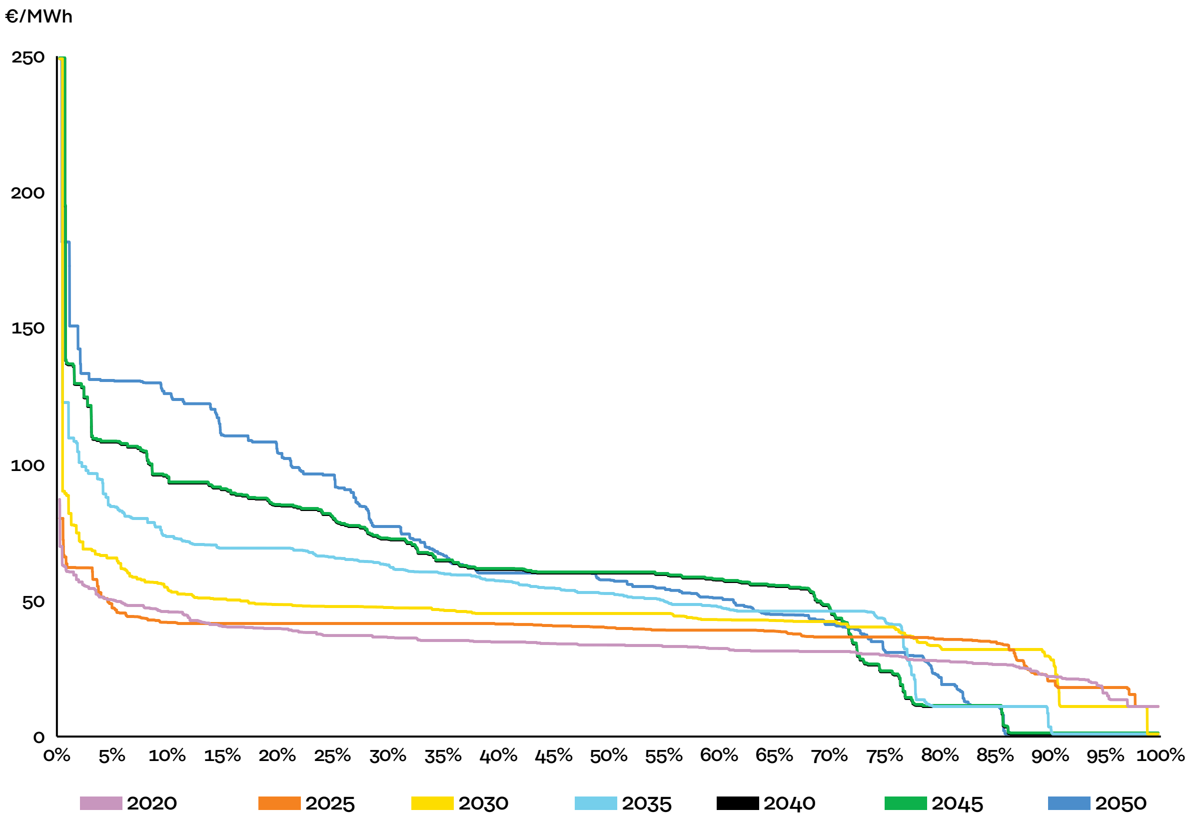
Figure 58 shows these price dynamics for the Direct Electrification Scenario together

Figure 58: Comparison of power prices, the LCOE and SRMC for gas-fired generation in Finland in the Direct Electrification Scenario (€$_{2020}$/MWh)



Source: CL power dispatch model results by Compass Lexecon

Figure 59: Price Duration Curves in the Direct Electrification Scenario (€/MWh)



Source: CL power dispatch model results by Compass Lexecon

with two additional price measures (explained below) providing further explanations of the power price development.

Of the two additional measures shown in Figure 58 one is the **short run marginal cost (SRMC) of gas power plants,** which shows a strong historical (2015-2020) correlation with the power prices in Finland because of the key role of gas as the marginal technology. However, this relationship disappears after 2030 when the SRMC rises sharply against only slowly rising wholesale power prices because of the strong and continuous increase of low variable cost renewable generation. The gas SRMC here is driven-up by rising CO_2 price.[8]

One reason for the nevertheless rising wholesale power prices is that despite the little actual gas power generation in the long term, the gas SRMC is still used by some assets for bidding strategy, for example nuclear and storages. Another reason is the increasing volatility of power prices driven by the increasing share of intermittent renewable generation. The evolution of **power price volatility,** expressed as standard deviation, is also shown in Figure 58. It can be seen that the volatility begins to increase from 2025 but starts plateauing in 2040s when the short-term and long-term storages are better positioned to arbitrage away the underlying price fluctuations. But to fully understand the impact of volatility on the increase of power prices, the changes in distribution of power prices, expresses as price duration curves, need to be discussed next.

Figure 59 presents the price duration curves in the Direct Electrification Scenario, showing an ordered distribution of power prices as a proportion of hours in a year. The key message of this figure is that compared to 2020 when price spikes and very low (zero) prices are relatively rare, in 2050 price spikes will be much more frequent – so will hours with very low prices. The more frequent price spikes (due to the large share of intermittent generation needing balancing) contribute to the increasing average wholesale power prices in the future.

4.6.3 Remuneration complements: rising wholesale prices support renewables deployment but are not sufficient to incentivise all capacity investment required for the transition

After better understanding the LCOE and power price results, it is useful to verify the economic incentives to invest in and build **the new sources of flexibility** (storages and peaking units) required in the modelled scenarios.

To indicatively quantify the investment incentives, “remuneration complements” **for peaking and storage technologies** (batteries, P2G2P, and OCGT) were determined in $€_{2020}$/kW. The remuneration complement (Table 15) compares the **average captured price** by the respective technology on the wholesale day-ahead market[9] (Table 13) with corresponding generation costs, here based on the **sum of annualised costs** per technology (Table 14).

On the revenue side, the average captured prices show that flexible technologies are able to capture (benefit from) the

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8 Despite the assumed Finnish switch from fossil to clean gas, the SRMC link to fossil gas and CO_2 was maintained because (a) the commodity pricing of clean and synthetic fuels is currently very uncertain, and (b) wholesale marginal power prices can be set by cross-border imports which may be based on fossil gas anyhow.

9 This is one source of revenue for a generation technology, particularly for peaking and storage technologies this is regularly topped-up by other sources of revenue that form (part of) the revenue complement required to incentivise the investment.

Table 13: Captured Price per technology in the Direct Electrification Scenario (€/MWh)

Price Received ($€_{2020}$/MWh)	2025	2030	2035	2040	2045	2050
P2G2P				101.3	120.0	131.4
Battery, large scale				74.9	80.3	84.7
New OCGT		102.4	114.1	134.3	174.6	197.8

Source: CL power dispatch model results by Compass Lexecon

Table 14: Sum of annualised costs for storage and peaking technology in the respective year, Direct Electrification Scenario (€/kW)

Sum of Annualised Costs per technology ($€_{2020}$/kW)	2025	2030	2035	2040	2045	2050
P2G2P				132	115	110
Battery, large scale				77	80	
New OCGT		47	54			

Note: LCOE for Batteries and OCGTs rise over time due to declining annual operating hours.
Source: CL power dispatch model results by Compass Lexecon

Table 15: Remuneration complements for new storage and peaking technologies required in a respective year, Direct Electrification Scenario (€/kW)

Remuneration Complement ($€_{2020}$/kW)	2025	2030	2035	2040	2045	2050
P2G2P				-8	27	5
Battery, large scale				40	36	
New OCGT		30	31			

Source: CL power dispatch model results by Compass Lexecon

increasing and more volatile wholesale prices due to their innate nature to dispatch (charge) during the most beneficial (profitable) hours.

On the cost side, these are based on the sum of the annualised CAPEX and OPEX values and the variable costs (i.e. fuel and VOM costs) for the respective new technologies. It is important to note that costs reported in **Table 14 comprise only costs for capacities installed in the respective year. Cost figures presented earlier in this report (e.g. Figure 54 and Figure 55) included costs for all capacities active in a respective year.**[10]

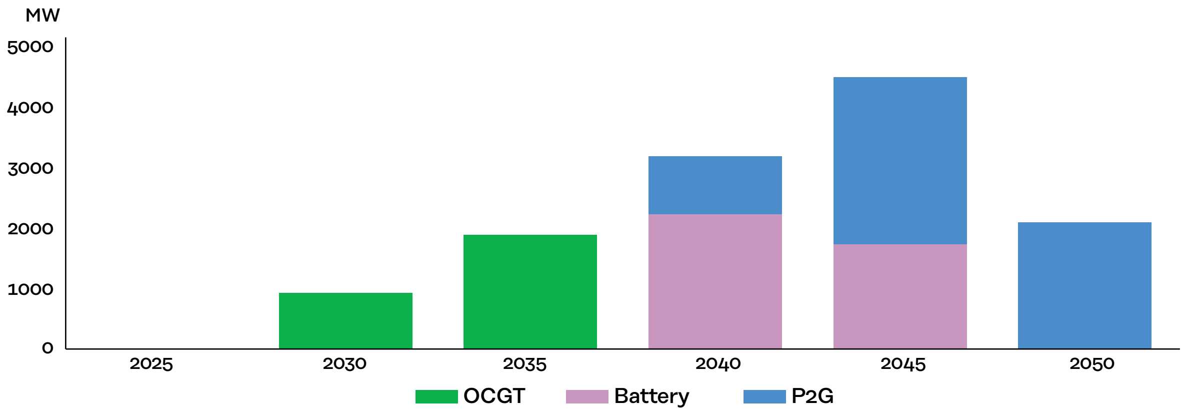
Because new flexible capacity additions do not occur in every studied year the associated costs with the new additions and therefore the remuneration complements are presented only for those years when the new investments actually happen, but additional remuneration might be actually required throughout the entire lifetime of the capacity and/or in the form of initial investment support. These new flexible capacity additions for OCGT, batteries, and PTG2P are shown in Figure 60.

To derive the indicative remuneration complement for storage and peaking technologies (Table 15), the captured prices from Table 13 are transformed from €/MWh to €/kW[11].

The positive values in Table 15 imply that the storage and peaking technologies (batter-

10 To derive the capacity costs in €/kW the sum of annualised costs per new technology is divided by the capacity of the newly installed capacity of corresponding technology
11 The transformation is based on multiplying the actual generation of a given technology with the captured prices and dividing by the corresponding newly added capacity.

Figure 60: New flexible capacity additions by technology [MW]



Source: CL power dispatch model results by Compass Lexecon

ies, P2G2P, new OCGT[12]) would not have sufficient economic incentives to add the required new capacities based on the assumptions of this study and the resulting uses of these resources in the day-ahead market. The results show that in the mid-term new OCGTs would need to enter the market in 2030s but later in 2040s these would be complemented by short-term (batteries) and mainly long-term (P2G2P) storages. An exception to the lack of remuneration incentive is P2G2P in 2040 when it would temporarily become profitable due to higher demand for flexibility.

In order for the needed flexible capacities to enter the market in the future the development of economic incentives should be carefully monitored. The indicative remuneration complement quantified here is based only on the day-ahead market revenues from energy (traditionally the main market and main source of revenues), but other revenue streams, such as from different ancillary services, would have to be assessed in their entirety to ensure that adequate incentives stimulate future investments into the needed flexible capacity.

4.6.4 End-user prices: End-users are largely shielded from higher energy bills

While electricity wholesale prices rise in the cost-efficient Direct Electrification Scenario the end-users are largely shielded from higher energy bills mainly because:

- the wholesale power prices make-up less than a quarter of electricity (related) costs borne by households;
- energy efficiency measures reduce electricity consumption compared to today, which dampens the impacts of price rises;
- changes in tariffs and expanded demand side flexibilities would allow end-users to reduce electricity off-take during expensive times or even profit from offering their flexibility to the network operators; and
- the increased usage of electricity – and associated costs – are balanced with a steep decline in fossil fuel usage saving the Finnish economy (and end-users) several billion Euros per year.

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12 New peaking units (OCGT) are needed in the model to supply demand peaks and provide security of supply – see sections 4.2.4 and 4.7.

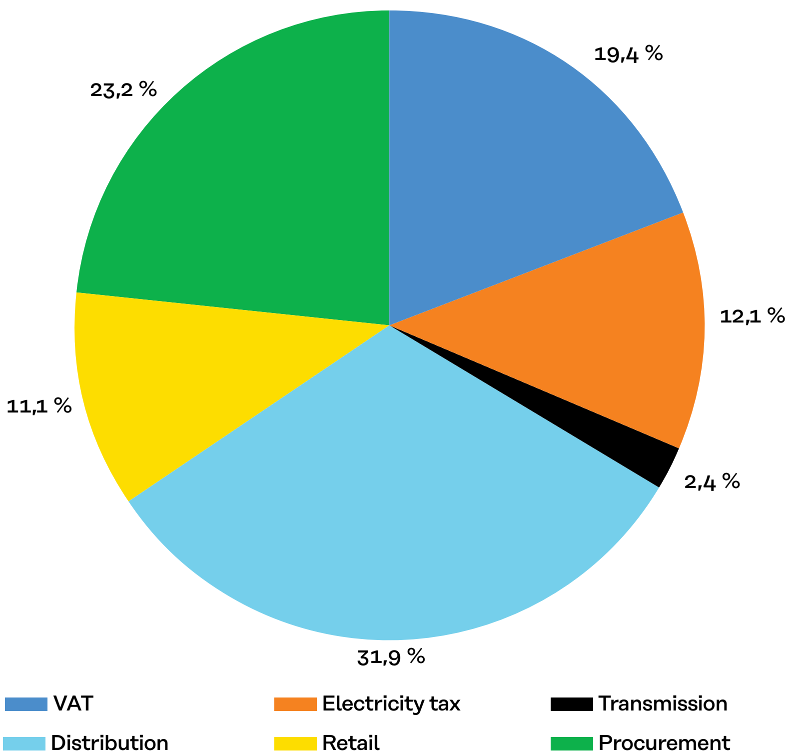
Currently, the **household electricity prices** of a customer in Finland are lower than the EU average, and, relative to purchasing power, are among the cheapest in Europe (Eurostat, 2020). The cost components of the final electricity bill of a household customer are illustrated Figure 61. As can be seen, the cost of energy procurement makes-up only 23% of the total bill. This means that even if the wholesale price were to double, the total bill paid by customer would increase only by less than a third.

Another interesting point is that the network cost represents one-third of the total cost, and currently this share is mostly made up of electricity distribution costs. Transmission cost contribute less than 3 % to the total bill. So even costly investments in the transmission infrastructure have only very minor impact on the bill paid by household consumers.

The last main cost component are taxes representing one-third of the total bill.

For **industry,** the basic structure of the total electricity cost is very similar to households consisting of energy, network costs, and taxes. Industry electricity users can buy electricity from the market like households or make a power purchase agreement (PPA) with electricity suppliers. Network costs for industry are slightly different from household consumers, as industry users pay for both active and reactive power in addition to the basic monthly fee and the consumed energy. The structure of industry electricity taxation is the same as for households, but the tax is lower. Taxation consists of lowered electricity tax (0.05 €ct/kWh), supply reliability payment (0.013 €ct/kWh), and 24% value added tax (VAT), totaling 0.078 €ct/kWh (Ministry of Finance, 2021). Sectors that are included in this lowered tax rate are

Figure 61: Components in a consumers' final electricity bill (5,000 kWh/a)



Notes: Situation as of 1.1.2021
Source: Finnish Energy based on the data of Energy Authority

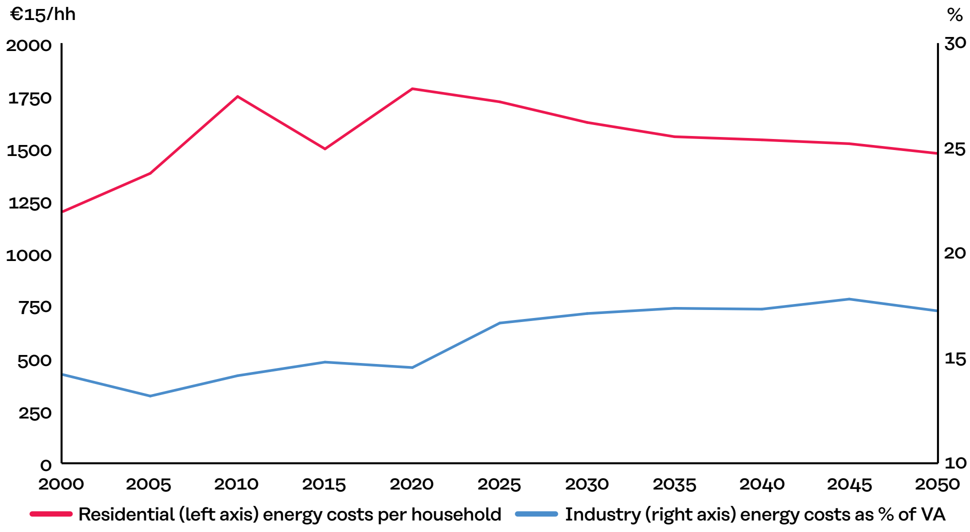
industry, mining, large greenhouses, and data centres with a capacity above 5 MW (Ministry of Finance, 2021). It is expected that heat pumps in district heating network are added to the lowered tax rate during 2021–2022.

The impact of the electricity price increase on households and the industrial sector in Finland can be analysed by looking at the **projected evolution of the energy expenses**[13], as shown in Figure 62. The industrial energy costs, expressed as a ratio to the industry value added, are increasing by around 25% from 2019 to 2050, while they were roughly stable historically. The Power to X fuels needed to fully decarbonise the sector and the electricity price increase contribute to this effect. However, this increase is moderate and likely to be in line with the EU trend, therefore the impact on industry competitiveness is likely to be much lower (and mitigated).

Thanks to significant energy efficiency improvements, especially through heat pump development, the average energy bill[14] of households would decrease between 2019 and 2050, despite the increasing electricity prices. It decreases by 14% over this period compared to its 2015 level, while it was historically following a generally increasing trend (+44% between 2000 and 2019).

Beyond changes in annual average energy costs, the changing temporal structure of energy prices is likely to lead to cost saving or even revenue generation options for end-users. As the volatility of wholesale power prices is expected to increase significantly, it is also likely that the **distribution system tariffs** will be partly based on the power-based price component, which is based on the highest power taken from the network. This means that end-users can reduce costs by flexible electricity use. In addition to implicit demand response, customers can also profit from explicit

Figure 62: Energy costs analysis in the residential and industry sectors, Direct Electrification Scenario



Source: POLES-Enerdata model results by Enerdata

13 The energy costs are the product of the consumed energy by the price of this energy. The investment in new equipment is not included in this figure. Taxes were assumed to keep a constant share of the price over the forecast period.

14 By energy bill, we mean the average energy costs per household. Energy costs are the household's energy consumption multiplied by its average price.

demand response, which means offering flexibility directly to balancing and ancillary service markets via a flexibility aggregator. There are also already existing demand response programs for heating, in which water-based storages, in addition to natural heat storage capacity of the buildings, enable flexibility in power consumption. Also, charging of EVs is very flexible, as charging can be scheduled to low demand hours.

To sum up, higher energy efficiency and flexibility in power use could reduce the electricity bill of end-users. It is therefore likely that the electricity bill of a household in the future would be lower than today, even if the wholesale price and electricity transmission costs would increase.

Finally, the full decarbonisation of the Finnish energy system also enables to progressively **phase out fossil fuels** thereby reducing – and ultimately eliminating – associated costs for end-users and the Finnish economy as a whole (Figure 63). The share of domestically supplied energy will thus be much higher by 2050. The fossil fuel imports are estimated to drop from around EUR_{2015} 3.5 bn in 2015 to 0 in 2050.

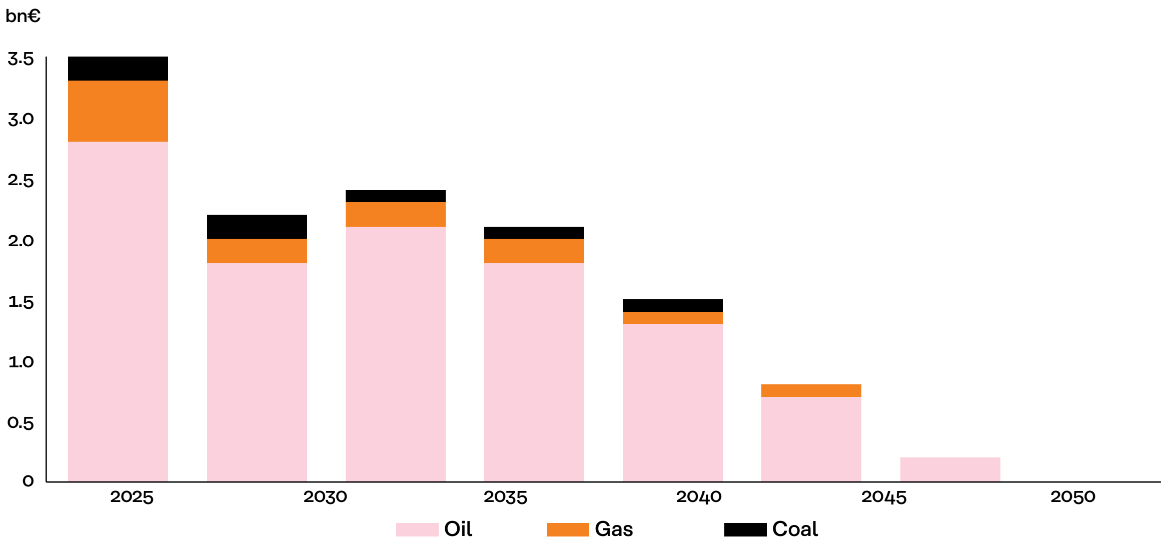
4.7 Security of supply (SoS): SoS is ensured by traditional and novel flexibility sources – with significant cross-border support

Key takeaways

- A fully decarbonised Finnish electricity system requires significant domestic flexibilities and import capacities to balance the system during phases of reduced domestic wind generation.
- The required domestic generation and storage capacities to ensure security of supply are already included in the cost-optimal generation mix.

The issue of security of supply already receives significant attention today as illustrated by globally reported recent black-out events. In electricity systems with high shares of renewable generation, provisions to keep-up security of supply are even more important.

Figure 63: Estimates of fossil fuels import costs (billion $€_{2015}$), Direct Electrification scenario



Source: POLES-Enerdata model results by Enerdata

Security of supply is inherently ensured when deriving the generation expansion pathways for the two scenarios, as capacity margins are considered as a constraint in the optimisation. Capacity margins ensure that the capacity available over a specific year always exceed the expected peak load in the respective year. Intermittent renewable capacities are not considered in calculating the available capacities, thereby also preparing for times of limited intermittent renewable generation.

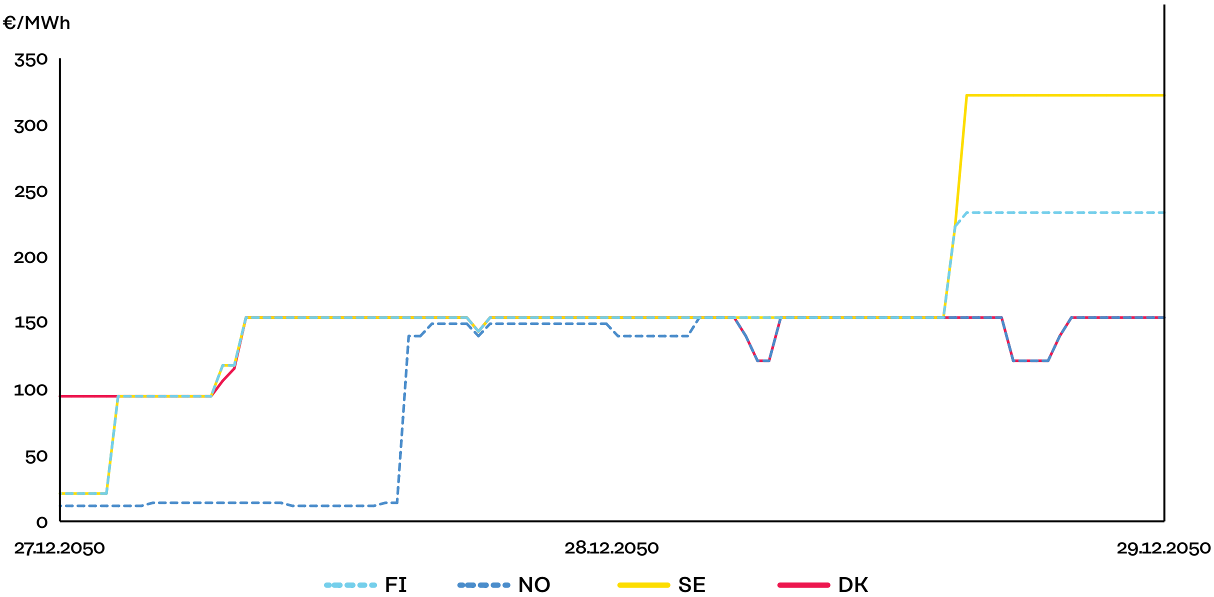
In this section, the resulting security of supply within the Finnish electricity system is discussed based on the Direct Electrification Scenario over a sample four-day situation in 2050 (from 27 to 30 December 2050) marked by high winter demand and a prolonged low generation of onshore wind, the largest power generation source by 2050.

It is first relevant to observe the price dynamics in the Nordic region (FI, NO, SE, DK) during the sample period (Figure 64). Prices exceed 150 €/MWh in the Nordic countries, with the lowest prices in Norway followed by Denmark, and the highest in Sweden and Finland peaking on 30 December 2050.

The Nordic market is tight over the sample period because wind generation is low at that time, representing only 27% of the region's total generation, while it typically (over the full year) represents 53% (Figure 65). The lack of wind generation is predominantly compensated by hydro power. Other low-carbon flexible sources (Biomass, P2G2P, DSR, and thermal power plants based on clean gas) play a smaller but still significant role in covering the wind shortfall.

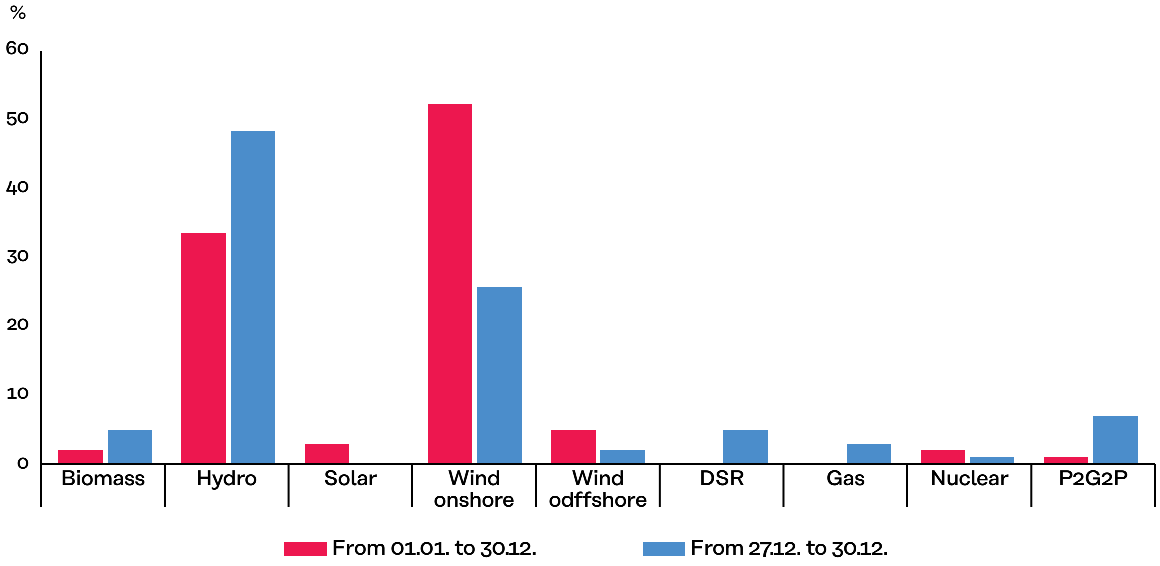
Despite limited wind generation, the Nordic countries remain net exporters to the other European countries, which are also subject to low wind generation over this period (Norway's exports exceed imports by other Nordic countries). In this situation, the Nordic region delivers the needed flexibility to the whole system via hydro generation, as illustrated by the higher than usual hydro generation.

Figure 64: Power prices in the Nordics 27 to 30 December 2050, Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

Figure 65: Percentage of generation per technology in the Nordics over the whole year 2050 and only 27-30 December 2050, Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

During the sample four-day period, extreme price spikes do not occur in the Nordic region, where the highest price in Finland is 250 €/MWh. This price level does not differ from price spikes during a typical 2020s winter (Finnish area price has been 250 €/MWh for instance on 30.11.2020 or 12.02.2021). This indicates that a market-based demand-supply balance is achieved also during a tight market situation.

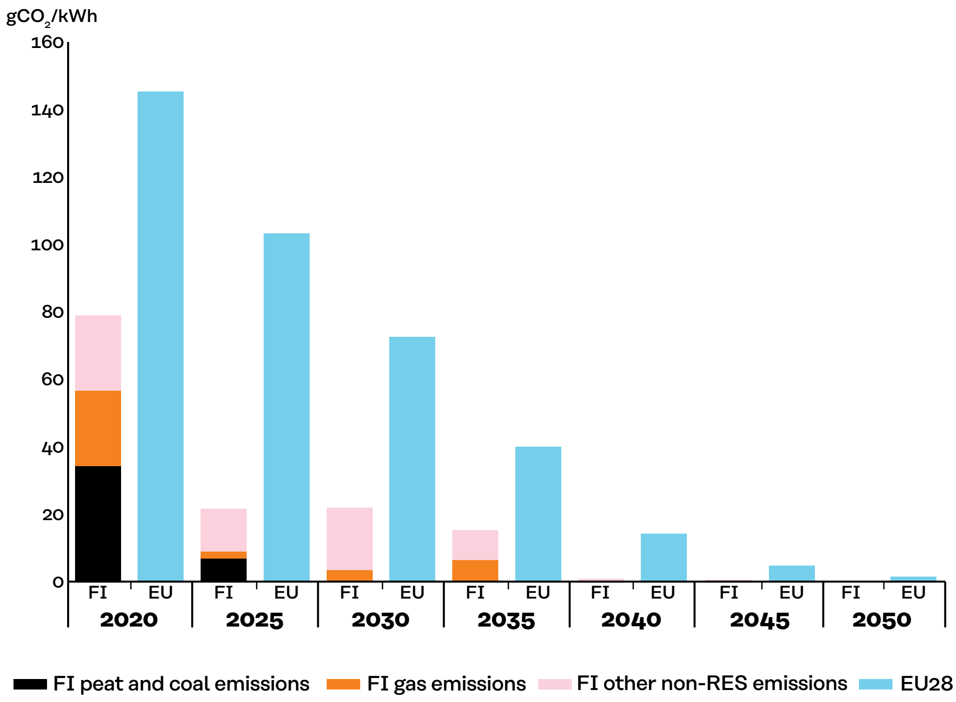
4.8 Carbon emissions: Finnish Power sector emissions fall well ahead of the EU-28 average

Key takeaways

- Both scenarios would almost eliminate electricity sector CO_2 emissions already by 2040.
- The Finnish CO_2 reduction trajectory in both scenarios would be well ahead of the EU average.

The Finnish electricity sector emissions are already well below EU-28 average emissions. A large part of the Finnish electricity sector emissions is currently made up from coal and peat-fired electricity generation. In both scenarios the phase-out of peat-fired generation would lead to a significant drop in electricity sector emissions already by 2025. Then, these emissions would decrease gradually until 2050 to reach the decarbonisation target. From 2040, emissions will be very low, at less than 1 $MtCO_2$ per year. This development of Finnish the electricity sector emissions is further illustrated in Figure 66. In both scenarios, Finnish electricity will be decarbonised well ahead of the EU-28 target.

Figure 66: Carbon content of Finnish and European electricity (gCO_2/kWh), Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.9 Reduced wind potentials: Limiting onshore wind potentials drives additional nuclear & battery capacities in 2050 – thereby increasing electricity cost in Finland

Key takeaways

- Restricting onshore wind build-up would shift the cost-optimal generation capacity mix in the Direct Electrification Scenario towards significantly more nuclear capacities and batteries while reducing longer-term P2G2P storage as longer-term flexibility is provided by nuclear generation.
- While increased imports would lead to slightly reduced Finnish domestic system costs, the total costs considering these imports increase compared to the baseline scenario.

Both of the analysed scenarios require a significant expansion of onshore wind generation capacities up to about 50GW in 2050 in both scenarios. Currently, however, the Finnish Defence Forces are limiting the build-up of wind turbines in parts of Eastern, Southern, and Northern Finland to avoid potential interference with radar. Additional restrictions may arise from limited public acceptability, especially in recreational areas. To assess the impact of such restrictions the onshore wind potential was limited to 25 GW (compared to 54 GW in the baseline scenario) in a sensitivity analysis outlined in this section.

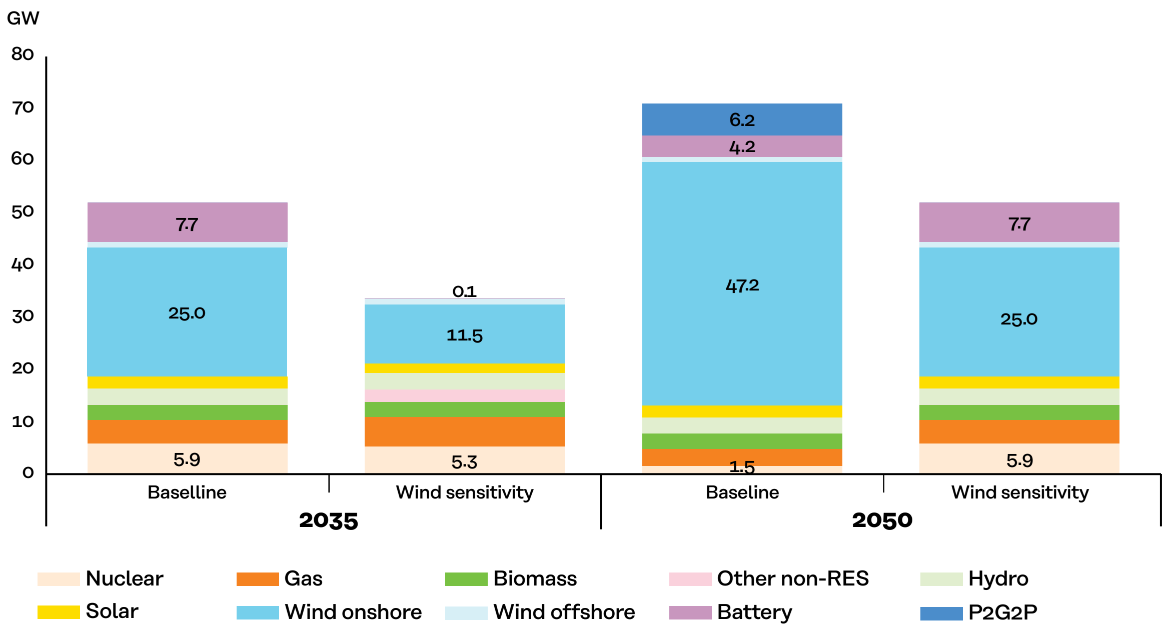
4.9.1 Reducing onshore wind potentials to 25 GW significantly increases the nuclear generation and battery capacities while reducing longer term storage capacities

As a result of the constrained onshore wind development, the capacity mix in the Direct electrification Scenario includes significantly more nuclear capacities (+4.5GW by 2050) compared to the baseline scenario (Figure 67) as this is the second cheapest generation technology based on the LCOE (Table 8).

Additional batteries (+4GW by 2050) offset P2G2P reduction (-6GW by 2050) as additional longer-term flexibility would be provided by nuclear generation.

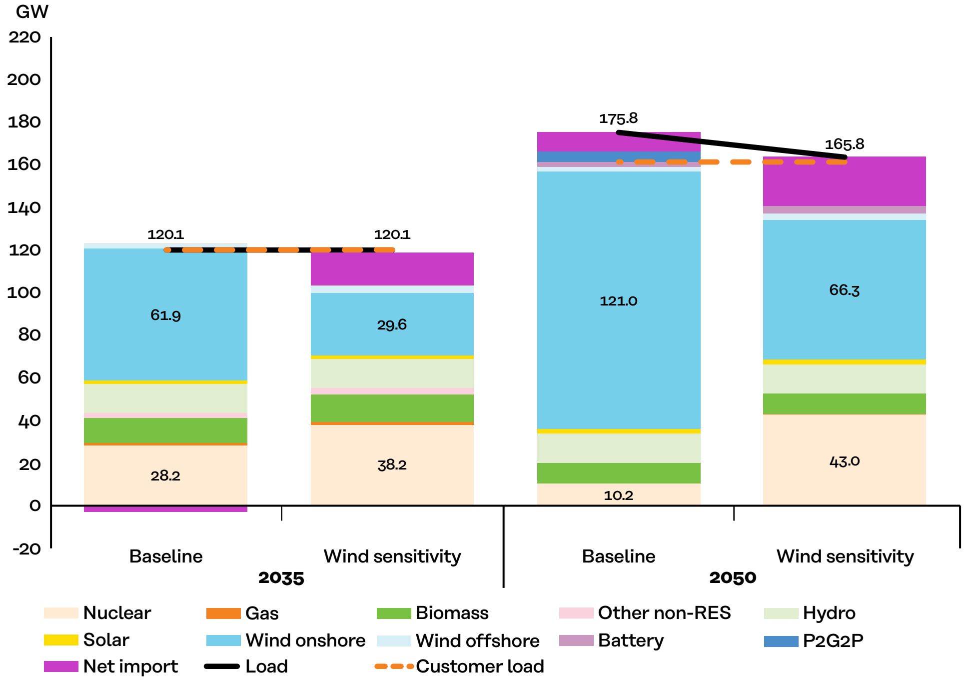
Despite the reduced onshore wind capacity, onshore wind would still provide 40% of the Finnish generation by 2050. Nuclear generation and imports would increase, representing 26% and 14% of Finnish demand by 2050, respectively. With the decrease of seasonal storage, storage losses decline, reducing gross consumption (Figure 68).

Figure 67: Impact of reduced onshore wind potential on storage and generation capacity in the Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

Figure 68: Impact of reduced onshore wind potential on gross consumption and generation storage and generation in the Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.9.2 Reducing onshore wind potentials to 25 GW would increase the cost of electricity in Finland and increase Finnish import dependency

The change in the capacity and generation mix due to limitations of onshore wind potentials slightly reduce total electricity system costs. Additional nuclear and battery capacities add to the system costs but are balanced-off by reduced costs associated by less wind and P2G2P capacities. Reduced domestic production due to reduced storage losses and increased imports lead to overall increasing costs of electricity consumed in Finland. This composite effect is evident both in 2035 and 2050 (Table 16).

Table 16: Impact of reduced onshore wind potential on electricity system cost

	2035			2050		
	Baseline	Reduced onshore wind potential	Differential	Baseline	Reduced onshore wind potential	Differential
Gross demand (TWh)	120.1	120.1	0	175.8	165.8	-10
Imports (TWh)	16.2	25.5	**9.3 (+56%)**	35.4	41.9	**6.5 (+18%)**
Annualised generation & storage cost (bn €$_{2020}$/a)	6.61	6.01	-0.6 (-9%)	7.14	6.87	-0.3 (-4%)
Annualised generation & storage cost including import balance (bn €$_{2020}$/a)	6.96	7.13	+0.2 (+2%)	8.48	8.71	+0.2 (+3%)
LCOE (€$_{2020}$/MWh)	53.7	57.6	**+3.9 (+7%)**	44.8	49.6	**+4.8 (+11%)**
Annualised costs per MWh consumed in Finland (€$_{2020}$/MWh)	58.3	59.7	**+1.4 (+2%)**	52.1	53.5	**+1.4 (+3%)**

Source: CL power dispatch model results by Compass Lexecon

4.10 Demand side flexibility (DSF): Cross-sectoral uptake of DSF is crucial for cost efficient decarbonisation via electrification

Key takeaways

- High uptake of demand side flexibility would be crucial for a cost-efficient decarbonisation via electrification.
- Reduced availability of demand side flexibility would increase the need for supply-side flexibility (storage) as well as additional generation capacities to cover storage losses – all leading to significantly increased overall system and electricity costs.
- The limited availability of gas storage capacities and suitable sites in Finland underlines the importance of using DSF up to their full potential.
- Ensuring the DSF potentials are used, might require additional incentives and information as well as broad deployment of respective digitalisation solutions.

Replacing dispatchable fossil-fired power plants with intermittent renewable generation would drive the need for system flexibility to maintain the balance between electricity consumption and production at all times. This flexibility can either be provided on the supply side (e.g. dispatchable renewable generation like hydropower or grid-level storage) or on the demand side with end-users shifting consumption away from peak-demand times.

This section focusses on demand side flexibility, its importance for electricity sector decarbonisation, the costs associated with reduced availability of DSF and potential bottlenecks leading to a reduced uptake of DSF potentials.

4.10.1 Demand side flexibility is available across all end-user segments – the impact analysis is based on two sets of assumptions for actual DSF offering

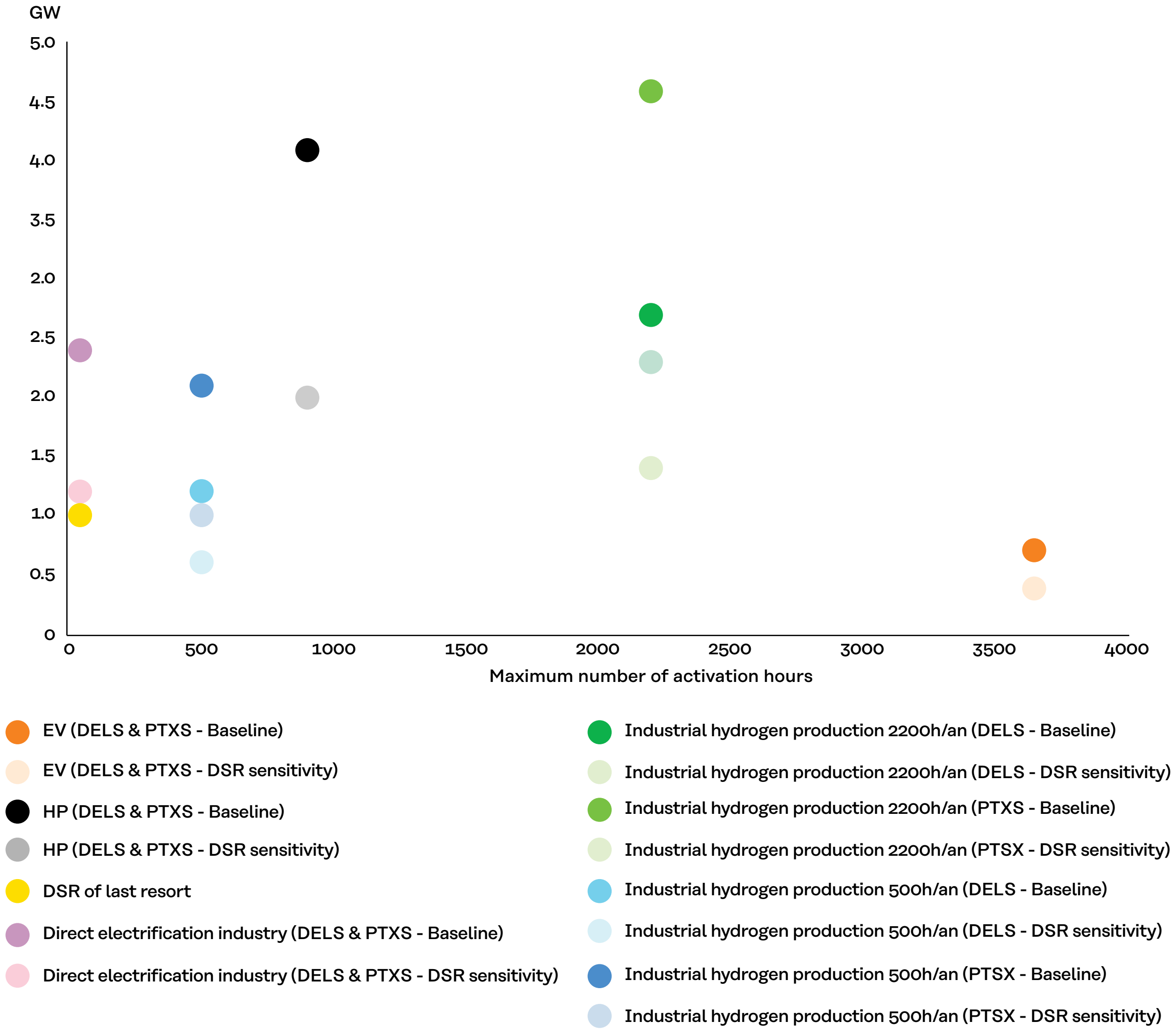
Demand side flexibility potentials are characterised by two parameters: (a) the load reduction potential and (b) the time over which the load can be reduced. Both parameters are characteristics of the respective end-user type offering flexibility.

To assess the impact of demand side flexibility on the Finnish electricity system, two sets of assumptions regarding its uptake ("baseline" and "reduced uptake") were compared regarding their effects on generation and storage capacity and the resulting electricity system cost differentials. Thereby, demand side flexibility across all sectors is analysed:

- in the building sector electricity demand for heat pumps is considered;
- in the mobility sector shifting charging times of EVs provides DSF;
- in the industrial sector parts of the electricity demand for industrial processes are already flexible in the form of demand side response (DSR) of last resort (i.e. interruptible supply) and with increasing electrification parts of the new process demand can also provide flexibility; but in the industrial sector the ability of continuous process industries (like steel production or the chemical industry) to provide DSF remain limited;
- in the energy sector shifting the times for hydrogen production provides flexibility.

Assuming that once an end-user offers their flexibility to the system they do so to their full potential, the two analysed DSF assumption sets vary only with respect to the available load reduction potential (Figure 69). For all demand types, total load reduction potential is halved in the reduced uptake assumptions – only the DSR of last resort is kept at the same level.

Figure 69: Demand-side flexibility potentials in 2050 – baseline (higher values) and reduced uptake (lower values)



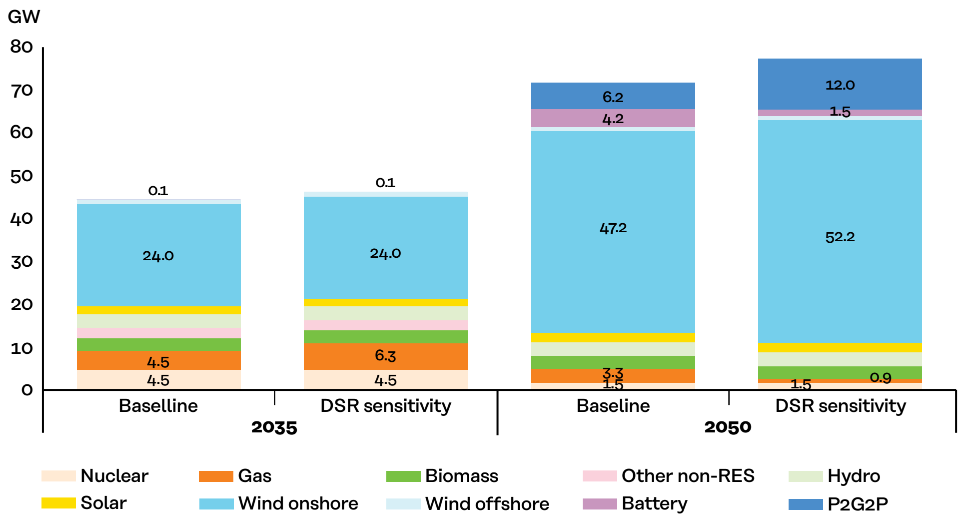
Source: Compass Lexecon

4.10.2 Reduced uptake of demand side flexibility increases the need for both supply side flexibility and additional generation (capacity)

Limiting the demand side flexibility would lead to the need for additional supply-side flexibility. Given limited potentials for additional hydro generation, this flexibility would be provided by batteries and P2G2P capacities. Given the limited efficiency (<40%) of long-term storage, also additional generation capacity would be required (Figure 70). The increased gross consumption is made up with additional wind generation (Figure 71).

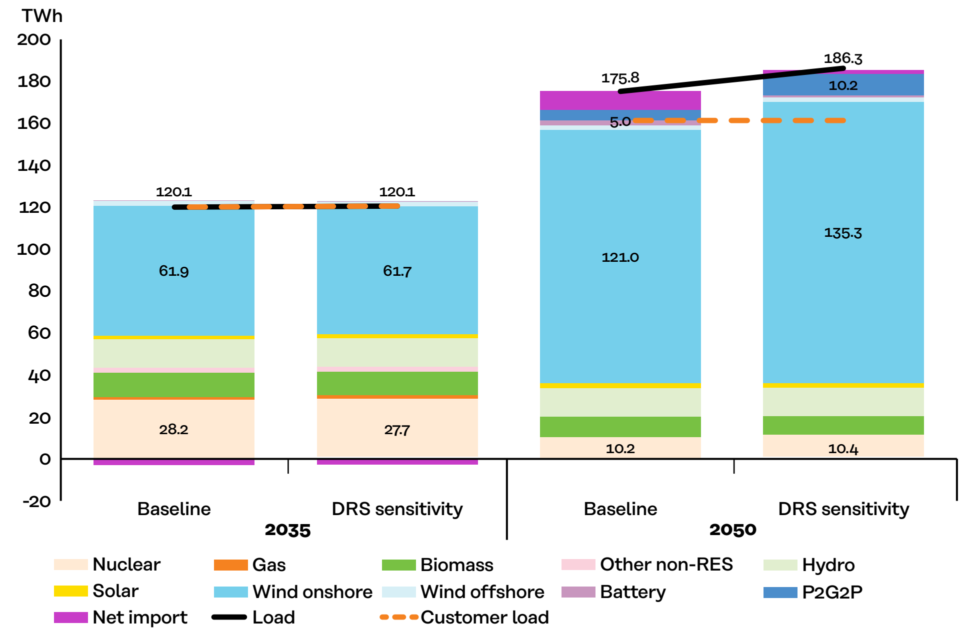
While the annual customer load remains the same under both assumption sets, limited demand-side flexibility leads to increased gross consumption due to storage losses.

Figure 70: Impact of reduced DSF uptake on storage and generation capacity in the Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

Figure 71: Impact of reduced DSF uptake on gross consumption and generation storage and generation in the Direct Electrification Scenario



Source: CL power dispatch model results by Compass Lexecon

4.10.3 Reducing DSF uptake by half would increase overall Finnish electricity system cost by almost a billion Euros$_{2020}$ per year in 2050 – but this effect would largely be balanced-off by decreased imports

A reduced uptake of demand side flexibility and the associated need for additional capacity and generation would significantly increase the electricity system costs. VOM and fuel costs are almost equivalent because the additional generation required in the sensitivity is provided by onshore wind. Under the reduced uptake assumptions, only about half of the DSF potential is offered to the system compared to the baseline scenario. The resulting annualised generation and storage costs would increase by 14% or more than a billion Euros per year (Table 17).

4.10.4 Key bottlenecks and enablers for demand side flexibility

While the importance and system-wide benefits of comprehensive offering of demand-side flexibility are highlighted above, there are significant hurdles towards achieving significant end-user participation.

Currently, financial incentives for this offering are generally limited. Spot price-based remuneration of flexibility has historically offered limited profit margins for both customers and aggregators (Belonogova, 2018). The changes in the spot price structure (higher peak prices with near-zero prices over extended periods of time – Figure 59) will provide some inherent mitigation already. Further improvement of incentives could be achieved by changes in grid tariffs (power-based, variable over time or dynamic). Also, the participation of DSF in

Table 17: Impact of reduced DSF uptake on system cost

	2035			2050		
	Baseline	Reduced DSF	Differential	Baseline	Reduced DSF	Differential
Gross demand (TWh)	120.1	120.2	+0.1	175.8	186.3	+10.5
Imports (TWh)	16.2	16.2	0	35.4	31.6	-3.8 (-11%)
Annualised generation & storage cost (bn €$_{2020}$/a)	6.61	6.72	+0.11 (+2%)	7.14	8.11	**+0.97 (+14%)**
Annualised generation & storage cost including import balance (bn €$_{2020}$/a)	6.96	7.14	+0.18 (+2%)	8.48	8.75	**+0.27 (+3%)**
LCOE (€$_{2020}$/MWh)	53.7	54.6	+0.9 (+2%)	44.8	46.9	**+2.1 (+5%)**
Annualised costs per MWh consumed in Finland (€$_{2020}$/MWh)	58.3	59.7	**+1.4 (+2%)**	52.1	53.7	**+1.6 (+3%)**

Source: CL power dispatch model results by Compass Lexecon

ancillary services markets (via aggregators – potentially also by offering demand increase flexibility) could open-up additional revenues streams and allow for much higher annual profits for DSF offerings. Finally, digitalisation (including machine learning) and automation could improve the uptake of DSF. New tools making controlling and aggregating flexibility resources easier and allow for the building of larger pools dynamically active on multiple marketplaces could increase remuneration and improve the attractiveness of DSF (Belonogova, 2018).

Complexity adds to end-user's reluctance to offer DSF potentials. Perceived complexity results from limited information about the availability of flexibility markets and the benefits of a participation as well as from multiple different marketplaces and difficulties to optimise profits from these marketplaces. Providing more information on the benefits of offering demand side flexibility could increase participation. The information aspect is thereby of particular importance for households (e.g. regarding the flexibility from heat-pumps and EVs) as they – unlike industrial end-users – generally lack energy sector expertise or access to respective services.

Power-to-X (PtX) adds significant future demand – and significant potential for demand response to the Finnish electricity system (Figure 69). DSF-induced reductions in electrolyser utilisation could, however, decrease the profitability of these significant investments. Again, the changing wholesale price structure might provide some inherent mitigation as production during periods of very high prices might not be profitable in the first place. A second limitation might arise from a continuous demand for the PtX product (generally hydrogen). Various forms of storage (local or centralised) would provide mitigation but also add to cost. Regarding larger scale storage in Finland, the limitations already identified with respect to supply-side flexibility (section 4.2.5) also apply here.

Policy recommendations

- Provide more information on the individual and system-wide benefits of demand side flexibility for the average consumers.
- Explore options to support end-consumers in their choice of aggregators or flexibility markets.
- Explore options to improve financial incentives for the uptake of demand side flexibilities (e.g. within the tariff and balancing system design)
- Explore making the demand side flexibility uptake a priority in the national energy and climate plan (NECP).
- Explore options to structurally improve the availability of demand side response potentials (e.g. the requirement for controllability of loads in building regulations)

5 Conclusions and next steps

The present study contributes to the ongoing Finnish decarbonisation debate by presenting a cost-efficient pathway in line with these targets and towards the full decarbonisation of the Finnish economy by 2050.

Our study finds that achieving these ambitious climate and energy targets is possible with foreseeable technologies, without overly optimistic energy efficiency gains, and without sustained increase of biomass use compromising the carbon sink if Finnish forests. Instead, strong direct and indirect electrification across the economic sectors avoids most of the historical greenhouse gas (GHG) emissions. The remaining GHG emissions from agriculture, industrial processes, and waste in 2050 are compensated by negative emissions from the deployment of bioenergy with carbon capture and storage (BECCS).

The role of indirect electrification using electricity-based hydrogen and other synthetic fuels ("power-to-X", PtX) in Finland's future energy system was specifically studied. PtX fuels are competitive in the heavy transport segment, and in the industrial sector PtX enables full decarbonisation of hard-to-electrify industrial processes. Industrial non-energy uses, notably chemical feedstocks, are decarbonised using bioenergy, for example feedstock based on industry waste liquids, and power-to-X fuels, as well as increased recycling.

The major cost-efficient source of decarbonised power in Finland under the specified scenarios is onshore wind, strongly supported by supply and demand side flexibility sources. Not developing the full economic potential of onshore wind or demand side flexibility therefore has large and costly consequences for the Finnish power system. Significant new domestic supply-side flexibilities will be required to balance the increasing intermittent wind generation and replace retired fossil generation. Specifically, power-to-gas-to-power (P2G2P) capacities provide weekly and longer-term flexibility and batteries provide intraday flexibility to balance wind generation especially from 2040 onwards. Electrification strongly impacts the transmission network, increasing the need for transmission capacity expansion. Distribution networks on the other hand need only a limited capacity expansion, but peak demand management will become essential. Both scenarios point out that the overall electricity production costs in Finland (LCOE) would decline by almost 30% by 2050 compared to today. Finally, the study shows that the increased usage of electricity – and associated costs – would be balanced by a steep decline in fossil fuel imports.

The study identifies several important **next steps** for enabling the cost-efficient decarbonisation in Finland. For industry, options for implementing needed incentives for carbon neutral processes and feedstock on the national and EU-level should be explored. Schemes for incentivising negative emissions should be analysed and a corresponding market established at national or EU-level. A favourable and competitive investment environment for industrial actors aiming for decarbonising investments should be ensured, which includes fast permitting and predictable regulation. Broad EU-level regulatory framework supporting the build-up of a hydrogen industry in Finland, including infrastructure should be developed. Finland should also develop a clear national hydrogen strategy. As wind power will play a significant role in the future Finnish power mix, measures to structurally reduce the impact of the Finnish Defence Forces' requirements on the build-up of wind generation capacities should be explored. Also, measures to reduce the length of permitting processes for wind parks should be analysed. To ensure the future availability of supply and demand side flexibilities the sufficiency of investment incentives should be regularly reviewed, and if necessary, options to improve these incentives should be explored.

Despite using comprehensive quantitative modelling frameworks, this study has some limitations: the sectoral energy demand of the paper and forest industry is not modelled separately, district heating is not modelled in detail, gas and hydrogen infrastructure and related costs are not explicitly modelled and bioenergy is modelled in aggregate. In the power sector the domestic transmission capacities were not modelled in detail and the interconnection capacities to Russia were not considered. Moreover, certain topics are beyond the scope of this study even though they may influence Finland's path to decarbonisation. Most notably, the availability and pricing of materials (e.g. rare earths) and of sustainable biomass were not studied in detail. And finally, as with any modelling work, the presented results depend on the assumptions used, particularly regarding energy efficiency gains, future technology costs and biomass availability.

During the development of this study close interaction with key Finnish stakeholders via workshops, interviews, and questionnaires provided valuable feedback on the study inputs and outputs as well as regarding the next steps required to enable cost efficient decarbonisation in Finland (summarised in Table 20).

Table 20: Next steps to enable cost efficient decarbonisation in Finland

Sector	Next step recommendation
Industry	
	Explore implementation of needed incentives for carbon neutral processes and feedstock on the national and EU-level.
	Explore national and European schemes for incentivising negative emissions and establish a respective market.
	Develop a clear national hydrogen strategy.
	Develop a broad EU-level regulatory framework supporting the build-up of a hydrogen industry in Finland, including the required infrastructure.
	Promote industrial companies to develop carbon neutrality roadmaps to help develop clear views of needed actions to decarbonise their operation and to enhance the discussion with stakeholders.
	Ensure a favourable and competitive investment environment for industrial actors aiming for decarbonising investments – including fast permitting and predictable regulation.
	Continuously assess re-investment cycles of major fossil energy users and incentives to switch to decarbonised technologies to avoid long-term lock-ins
Transport	
	Explore balanced support measures for the investments into carbon neutral vehicles – especially for low-income rural areas
	Explore options to increase incentives for switching to low-carbon vehicles (e.g. renewing the transport tax and payment system and/or implementing an emission trading scheme including the transport sector)
	Explore the support for piloting of synthetic fuel and hydrogen production
	Explore options to support the build-up of hydrogen refuelling stations in Finland – essential for enabling decarbonisation of heavy road traffic.
	Explore options to enable levelling synthetic fuel cost on par with fossil fuels.

Sector	Next step recommendation
Buildings & services	
	Explore the support of (piloting) projects for the transformation of existing district heating networks for the utilisation of heat pumps.
	Explore the support of (piloting) projects for waste heat capturing for district heating, e.g. data centres and electrolysers.
	Explore (additional) support for improving energy efficiency in buildings as well as investments into automation, distributed energy resources, or other energy efficiency improvements.
	Increase information provision and education for energy consumers about energy efficiency and related benefits.
	Explore measures to structurally reduce the impact of the Finnish Defence Forces' requirements on the build-up of wind generation capacities (e.g. setting out restrictions in advance, more transparent discussions on building plans, research and develop solutions to limit interference between army radars and wind turbines).
	Explore measures to reduce the effects of long permitting processes for wind parks (e.g. potential increase public administration permitting capacity or courts' resources to handle complaints)
	Follow the process of nuclear life-time extension permitting and timely explore options for substituting nuclear generation, if life-time extensions are expected to be not granted.
Supply side flexibility	
	Regularly review the sufficiency of investment incentives for supply side flexibilities and if necessary, explore options to improve these incentives.
	Explore necessary support for the build-up of hydrogen (storage) infrastructure supporting the build-up of P2G2P capacities required to balance intermittent wind generation
	Explore options for the (increased) interconnection of Finnish gas and future Finnish hydrogen infrastructure with the rest of Europe to further improve the availability of flexibility to the Finnish energy systems.
	Regularly review the accessibility of TSO's ancillary services markets for all types of supply-side flexibilities (particularly batteries of all types) and explore options for joint TSO and DSO flexibility markets.
Demand side flexibility	
	Provide more information on the individual and system-wide benefits of demand side flexibility for the average consumers.
	Explore options to support end-consumers in their choice of aggregators or flexibility markets.
	Explore options to improve financial incentives for the uptake of demand side flexibilities (e.g. within the tariff and balancing system design)
	Explore making demand side flexibility uptake a priority in the national energy and climate plan (NECP).
	Explore options to structurally improve the availability of demand side response potentials (e.g. the requirement for controllability of loads in building regulations)
Transmission network and cross-border lines	
	Provide political support for interconnection projects, for example by speeding-up permitting
	Continue the active communication amongst neighbouring TSOs to identify needed expansions early enough and expand this active discussion towards regulators.
	Explore streamlining the permitting process of transmission lines to ensure, that transmission capacity will not limit uptake of energy intensive industry and new generation.
	Expand existing approaches for early detection of connection expansion needs and respective grid upgrade requirements to be fed in network planning and permitting processes.
	Explore the need to support new electricity transmission technologies e.g. regarding permitting
	Assess the optimal spatial layout of the energy system considering alternative energy carriers
	Integrate the network development planning for electricity, gas and hydrogen
Distribution network	
	Explore the implementation of power-based components in the network tariff for households to incentivize peak power reductions e.g. to incentivise smart EV charging
	Explore how to increase the TSO and DSO interaction regarding flexibility markets

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APPENDICES

A. POLES-Enerdata full-energy balance model

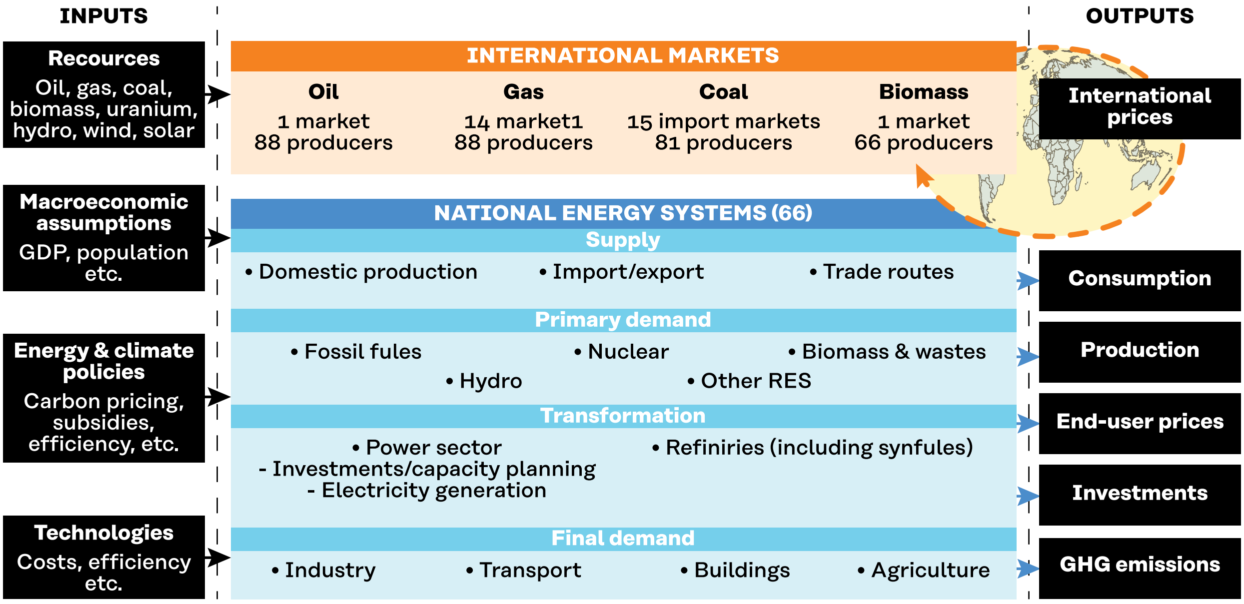
A1 General presentation of the model

The POLES-Enerdata (Prospective Outlook on Long-term Energy Systems) model is a recognised multi-issue energy model (similar to PRIMES) that relies on national energy balances combined with economic, policy and technological scenarios to withdraw energy production, consumption, and greenhouse gas (GHG) emission projections. POLES-Enerdata's geographical coverage includes the EU28 countries. Figure 29 show the general structure of the model, with its main inputs, outputs and covered sectors.

Enerdata co-develops and uses the internationally recognised POLES-Enerdata model to provide quantitative, scenario-based, empirical and objective analyses. Because the POLES-Enerdata model is used for many members of the energy sector (industry, governments, European Commission, etc.), it is very well adapted to forecast the effects of different energy-related engagements (demand-supply, GHG emissions limitations, promotion of renewables and energy efficiency, energy security issues, etc.). In addition, with its global coverage and the endogenous calculation of demand, supply and prices of numerous energies including oil, gas, and coal, the POLES-Enerdata model is very relevant to capture all the impacts of energy policies and climate change measures and to ensure that all the forecasts are coherent within the global environment.

POLES is used and developed by Enerdata, the European Commission's JRC in Seville and the CNRS GAEL Energy (formerly EDDEN of the University of Grenoble). It is used to provide quantitative, scenario-based, empirical and objective analyses

Figure 72: POLES-Enerdata multi-issue energy model



Source: Enerdata

by many members of the energy sector (private companies, governments, European Commission).

The model is a world energy-economy partial equilibrium simulation model of the energy sector, with complete modelling from upstream production through to final user demand and greenhouse gas emissions. The simulation process uses dynamic year-by-year recursive modelling, with endogenous international energy prices and lagged adjustments of supply and demand by world region, which allows for describing full development pathways to 2050. Figure 73 presents the geographical coverage of the POLES-Enerdata model, with a global coverage including 66 countries or country aggregates. All EU Member States are covered individually, including Finland.

The use of the POLES-Enerdata model combines a high degree of detail for key components of the energy system and a strong economic consistency, as all changes in these key components are influenced by relative price changes at the sectoral level. The model provides technological change through dynamic cumulative processes such as the incorporation of Two Factor Learning Curves, which combine the impacts of "learning by doing" and "learning by searching" on technologies' development. As price induced diffusion mechanisms (such as feed-in tariffs) can also be included in the simulations, the model allows for consideration of key drivers to future development of new energy technologies. One key aspect of the analysis of energy technology development with the POLES-Enerdata model is indeed that it relies on a framework of permanent inter-technology competition, with dynamically changing attributes for each technology.

The model provides a complete endogenous calculation from upstream activities (supply, prices of several energies including oil, gas and coal) to final user demand. Figure 74 provides a graphical view of the various model features on the energy demand, supply and transformation sides. POLES-Enerdata offers a mixed approach based on:

Figure 73: POLES-Enerdata geographical coverage

		66 countries	
REGIONS	**SUB-REGIONS**	**COUNTRIES**	**COUNTRY AGGREGATES**
North America		USA, Canada	
Europe	EU15 EU25 EU28	France, United Kingdom, Italy, Germany, Austria, Belgium, Luxembourg, Denmark, Finland, Ireland, Netherlands, Sweden, Spain, Greece, Portugal, Hungary, Poland, Czech Republic, Slovak Republic, Estonia, Latvia, Lithuania, Slovenia, Malta, Cyprus, Croatia, Bulgaria, Romania, Iceland, Norway, Switzerland, Turkey	Rest of Europe
Japan – South Pacific		Japan, Australia, New Zeland	Rest of South Pacific
CIS		Russia, Ukraine	Rest of CIS
Latin America	Central America South America	Mexico Brazil, Argentina, Chile	Rest of Central America Rest of South America
Asia	South Asia South East Asia	India China, South Korea, Indonesia, Malaysia, Thailand, Viet nam	Rest of South Asia Rest of South East Asia
Africa/Middle East	North Africa Sub-Saharan Africa Middle East	Egypt South Africa Saudi Arabia, Iran	Rest of North Africa X2 Rest of Sub-Saharan Africa Gulf countries: Rest of Middle East

Source: Enerdata

— a "top-down" modelling for sectorial demand, which is directly related to activity, prices and technologies through econometric equations; for each key economic sector energy consumption is distinguished between substitutable fuels and electricity[1]; and
— a "bottom-up" approach for the power sector (explicit representation of each type of technology as well as their costs).

Key features of the POLES-Enerdata model are summarized in the following:
— long-term (up to 2050) simulation of world energy scenarios/projections and international energy markets;
— world energy supply scenarios by main producing country/region with consideration of reserve development and resource constraints (88 producing countries/regions);
— outlook for energy prices at international, national and sectoral level;
— disaggregation into 15 energy demand sectors, with over 40 technologies (power generation, buildings, transport);
— detailed national/regional energy balances, integrating final energy demand, new and renewable energy technologies diffusion, electricity, hydrogen and Carbon Capture and Sequestration systems, fossil fuel supply, and uranium (66 consuming countries/regions, see Figure 73);
— full power generation system (and feedback effect on other energies);
— impacts of energy prices and tax policies on regional energy systems;
— national greenhouse gas emissions and abatement strategies; costs of national and international GHG abatement scenarios with different regional targets/endowments and flexibility systems;
— CO_2 emissions Marginal Abatement Cost Curves and Emission Trading System analyses by region and/or sector, under different market configurations and trading rules;
— technology diffusion under conditions of sectoral demand and inter-technology competition based on relative costs and merit orders; and
— endogenous developments in energy technology, with impacts of public and private investment in R&D and cumulative learning experience. Induced technological change of climate policies.

Figure 74: POLES-Enerdata main issues and topics covered

ENERGY DEMAND	ENERGY SUPPLY	TRANSFORMATION
• 66 countries • 15 detailed sub-sectors: industry, buildings & transportation, incl. detailed description of large Energy Intensive Industries: steel, aluminium... • All key energies: oil, gas, coal, power, biomass, solar, wing • End consumer prices • Detailed demand technology description (buildings, transport) • Demand function based on activity levels, prices, effects, autonomous technological change	• Oil, gas, coal and reneweables • Recources, discoveries and reserves for 88 producing countries • Production strategies (countries) • Unconventional oil and gas • International and regional prices: oil, gas, coal, biomass • Development potential for renewables • Oil, gas, coal and biofules, imports & exports	• 30 different power generation technologies • Simulation of future power generation mix by country • Power capacity planning • Electricity load forecasting • Power price analysis • Technology availability scenario: nuclear revival or phase-out, CCS, wind & intermittency... • Impact of support schemes for renewables (feed-in tariffs...) • Hydrogen

Source: Enerdata

1 POLES-Enerdata uses a "putty-clay" approach to determine the inter-fuel substitution process.

A2. Final energy demand: sector and fuel coverage

A2.1 Sector coverage

Final energy demand is detailed in the POLES-Enerdata model for all countries and country groupings covered, by sector, sub-sector and by energy. The sectoral coverage comprises 15 sub-sectors in buildings, agriculture, transportation and industry, including a detailed description of large energy intensive industries such as steel. International bunkers are also covered.

Industry

The industry sector includes mining and quarrying activities, the manufacturing industry, as well as the construction and public works industry. It excludes all modes of transport, even those used by the industry.

The industry sector is split into five sub-sectors:

— 4 energy-use sectors
    - **Iron & Steel** (NACE division C24 - excl. group C244, classes C2453 & C2454): manufacture and casting of iron and steel
    - **Non-metallic minerals** (NACE division C23): includes e.g. the production of glass, ceramic and cement
    - **Chemicals** (NACE divisions C20 and C21): includes petrochemicals, but excludes petrochemical feedstocks
    - **Other industry** (NACE divisions B07, B08, sections F and C – excluding divisions C19, C20, C21, C23, C24 but including group C244 and classes C2453 & C2454): encompasses all other industrial branches not mentioned otherwise, e.g. construction, food and tobacco, mining, machinery, non-ferrous metals, paper and pulp, transport equipment, textile and leather, wood and wood products.

— *A non-energy use sector*, i.e. products used in the petrochemical industry (e.g. naphta), for the production of ammonia (natural gas), for electrodes (carbon) and all other products used for their physical-chemical properties (bitumen, paraffin motor oils, etc.)

Buildings and agriculture

Buildings are split into two categories:

— **Residential**: energy consumption of households

— **Services**: energy consumption of commercial and publics services (NACE sections G, I to N and S)

The agriculture sector (NACE section A) covers all energy-related activities of the sector but excludes the livestock and the corresponding emissions.

Transport

The transport sector includes all modes of transportation regardless of to whom they belong, and to what purpose the transport serves. Air and marine bunkers (international transport) are excluded. Generally, transport consumption includes the consumption of the transport infrastructures (stations and airports), pleasure boats and the consumption of dock side loading and unloading services. Transport is broken down according to the four main types of infrastructures:

— **Road**: includes fuels used in road vehicles, agricultural and industrial highway use, but excludes military consumption
    - Private road transportation of passengers (cars)
    - Public road transportation of passenger (buses)

— Road transport of goods (light-duty vehicles and trucks)

— **Rail**: transportation of passengers and goods in trains, including industrial railways

- **Air**: transportation of passengers in planes
- **Other transport**: domestic navigation

Bunkers

International bunkers are represented at world level and split into two categories:

- **International aviation**: fuels for aircraft for international air transport
- **International sea transport**: fuels for international marine navigation (sea, lakes, waterways, coastal waters)

A2.2 Fuel coverage

Overall, all relevant fuels are considered in the individual subsectors, including electricity, oil, gas, coal, biomass, biofuels, heat and hydrogen. In the building subsectors (residential and services), specific electricity uses (lighting & appliances) are modelled differently from substitutable energy uses, enabling to precisely represent difference in drivers and trends between these uses, e.g. digitalisation driving the specific demand up.

A2.3 Technology coverage

In addition to this, the transport sector benefits from a more detailed, bottom-up oriented technology description.

POLES-Enerdata represents four main vehicles technologies: conventional, electric, hybrid, and hydrogen fuel cells. The total stock of vehicles is endogenously projected, and broken down by technology, a defined rate of cars is replaced each year and vehicles types are in competition for new sales. Modal share depends on the existing stock of vehicle, fixed and variable costs, and the maturity of the technology. Bioenergy (including biogas and biofuels) is considered as an option to offset fossil fuels in conventional and hybrid vehicles.

A3 Electricity sector: main features and technology coverage

The modelling of the electricity sector in POLES-Enerdata follows truly a multi-issue approach, from top-down econometric characterisation of demand to bottom-up calculation of future capacity additions and dispatch of power generation. The diagram below provides an overview of the main considerations accounted for in the representation of the electricity sector.

The modelling approach accounts for 30 power plant types. These cover existing technologies such as conventional fossil-fuel, nuclear and existing renewable-based generation assets, as well as new technologies (e.g. carbon capture and storage for coal, gas and biomass, generation IV nuclear reactors).

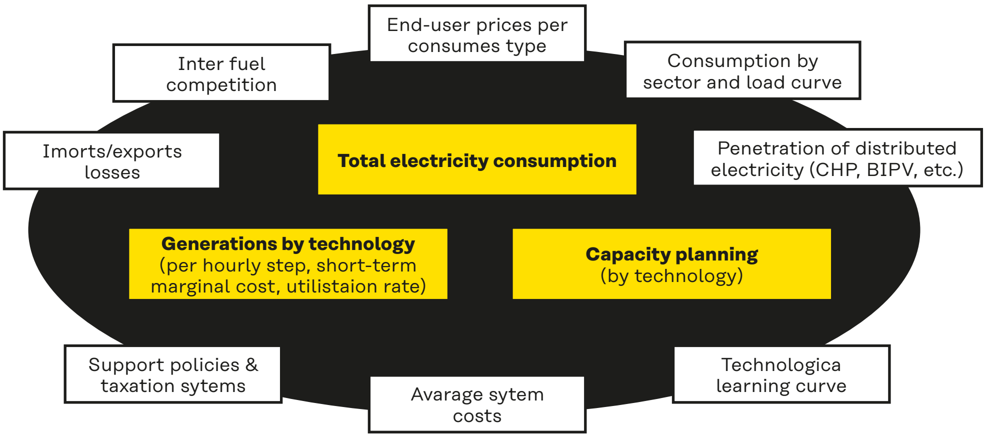
Coal and lignite: 6 technologies

- Gas: 5 technologies
- Oil: 2 technologies
- Nuclear: 2 technologies
- Renewables: 15 technologies across various sources (bioenergies, geothermal, hydro, solar, wind)

With this large coverage, the modelling framework allows to distinguish must-run from merit-order technologies, competing from non-competing options, as well as distributed, decentralised and centralised generation means. Multi-fuel is not explicitly modelled, but rather accounted for using respective shares of fuels in the generation planning.

Each technology is characterised by various economic, technical, and environmental parameters:

- Input fuel
- Lifetime
- Efficiency of transformation
- Auto-consumption rate
- CO_2 capture rate (for technologies equipped with CCS)
- Fixed costs
- Variables costs
- Discount rate



A4 GHG emissions

The POLES-Enerdata model covers all CO_2 emissions from fuel combustion, in final energy demand sectors, as well as energy supply and transformation (including power generation). It also includes GHG emissions from industrial processes (e.g. CO_2 emissions from chemical industry processes) and energy sectors (e.g. CH_4 fugitive emissions from gas transport). Overall, POLES-Enerdata endogenously represents all GHG emissions except emissions from agricultural activities (livestock, etc.) and Land-Use, Land-Use Change & Forestry (LULUCF).

A5 Input database

The POLES-Enerdata model relies on a robust input database, including historical series for energy demand, supply, prices and GHG emissions, exogenous forecast series (macroeconomic drivers, energy resources) and techno-economic data. The main input data sources are presented below:

- macroeconomic data: World Bank, IMF, CEPII, UNPD;
- historical data on energy demand, supply, and prices: Enerdata databases (derived from IEA, harmonised and enriched by national statistics);
- energy resources: BGR, IEA, CEDIGAZ, FAO, national sources;
- techno-economic data (costs of energy technologies, equipment rates, etc.): gathered both from international and national statistics over the course of several projects (buildings, transport, industry). Power generation technologies data: multiple datasets available (IEA WEO data currently used).

In the framework of the current study, this default POLES-Enerdata input database was updated and complimented for some series based on research from the consortium (LUT in particular), for instance for socio-economic projections. These specificities are presented below.

Macroeconomic assumptions:
Finnish population projections used in the study are based on the Population forecast 2019 from the Official Statistics of Finland 2019, shown on Figure 75 below. Economic projections, including GDP evolution and sectoral breakdown, were derived from a LUT analysis based on Tilastokeskus, 2020; Ministry of Finance, 2020; VATT Institute for Economic Research, 2016. They are presented on Figure 76 below.

Figure 75: Finnish population projections, in Millions (source: Official Statistics of Finland, 2019)

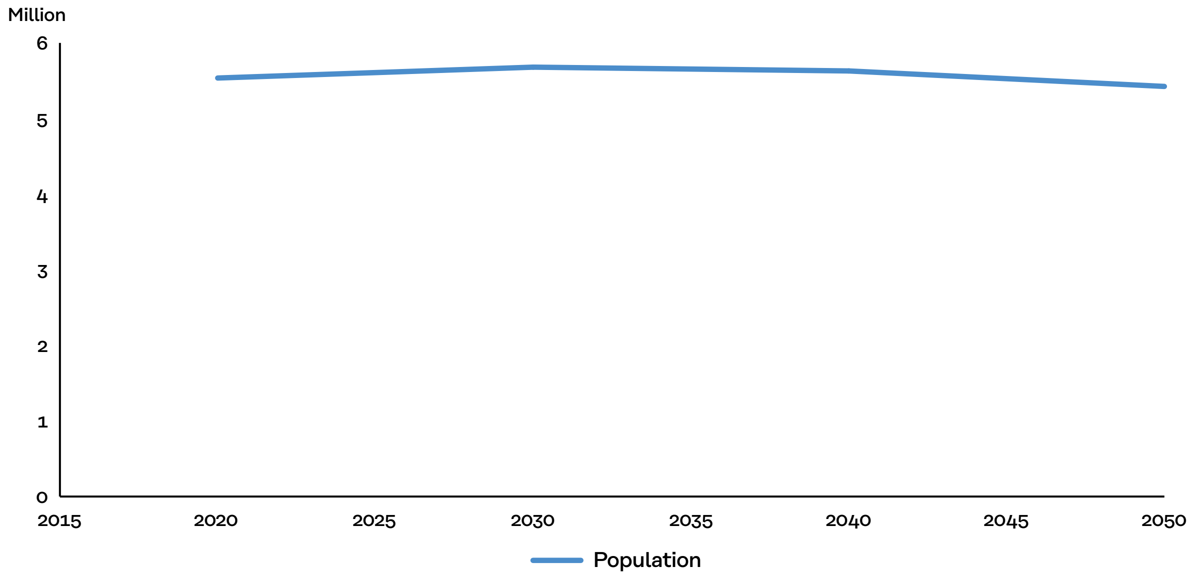


Figure 76: Sectoral and total Finnish real GDP projections, in Billion EUR2013 (source: LUT analysis based on Tilastokeskus, 2020; Ministry of Finance, 2020; VATT Institute for Economic Research, 2016)

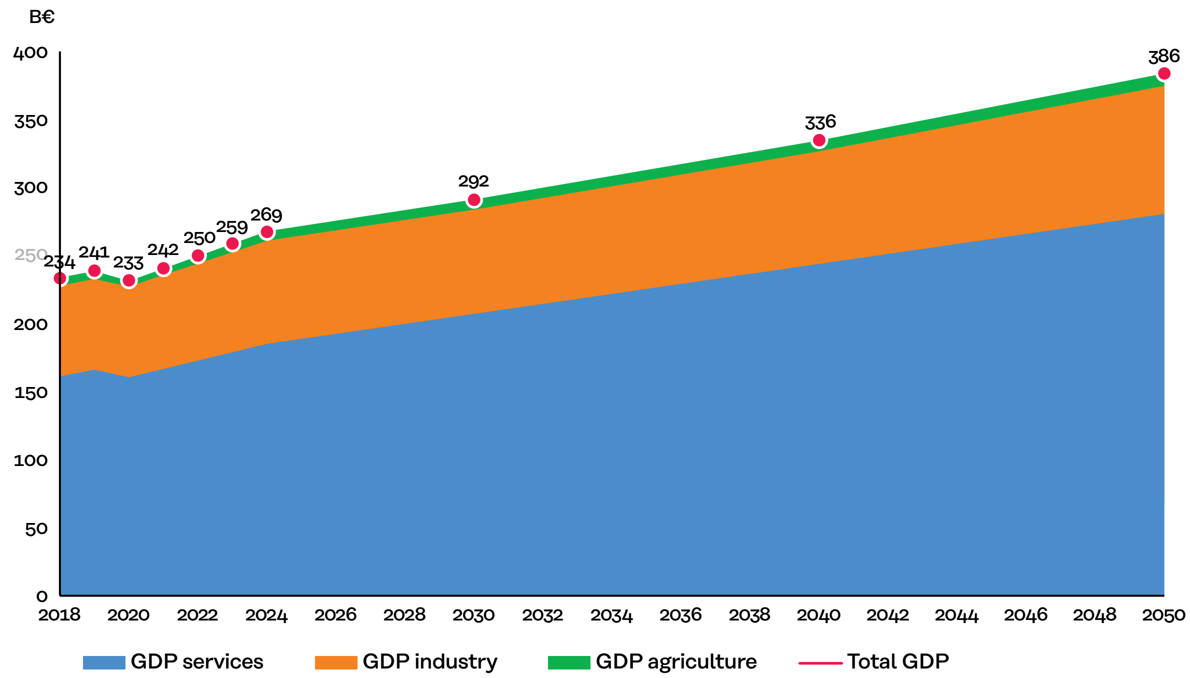
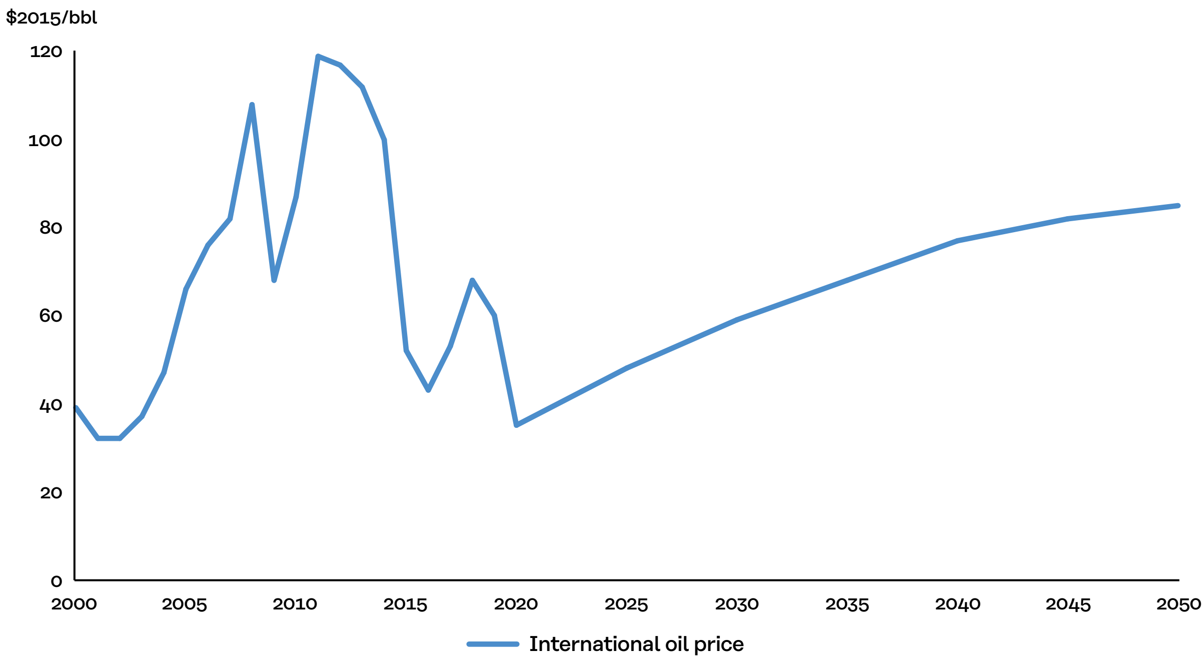


Figure 77: International oil price evolution (source: Enerdata's EnerFuture projections)



Regarding the rest of the world, population forecasts are based on the Medium Fertility Scenario of the United Nations, while the source of GDP projections is Oxford Economics[2]. The recent evolutions of the global economy (COVID-19 pandemic, recovery) are considered by these figures. These forecasts feature an average yearly growth of 1.7% over 2020-2050 at the EU level, and of 2.8% at the global level.

Commodity prices:

Assumptions considered for international fossil fuel market prices come from Enerdata's EnerFuture projections (updated Fall 2020 following Covid crisis, to take into account effects of the global pandemic on prices) and are presented on Figure 77. Developments up to 2030 are comparable to World Bank projections.

A6. Modelling overview & key assumptions

Residential sector:

In the residential sector, activity drivers are:

- Population, from which a number of households is derived.
- GDP per capita, used in the model as a proxy for household income, given that the evolution only is relevant here.

Based on these activity drivers, along with the consideration of an energy price effect and energy efficiency gains, the model calculates projections for specific electricity consumption (appliances, lighting, AC) and thermal uses consumption (space heating, water heating, cooking).

2 Oxford Economics, Date of Update: 6th November 2020. Oxford Economics updates their forecasts monthly and more up-to-date forecasts are available upon enquiry.

For thermal uses, based on the relative costs of each solution (including equipment and fuel costs), the model derives the energy mix between oil, gas, coal, electricity, district heat, bioenergy and H2/PtX. This process takes into consideration the existing equipment and their lifetime.

The model also includes an endogenous development for distributed solar panels (both PV and heaters) based on cost competitiveness and technological maturity.

Services sector:
The main driver is the added value of the services sector. Based on this driver, along with the consideration of an energy price effect and energy efficiency gains, the model calculates projections for specific electricity consumption (appliances, lighting, AC) and thermal uses consumption (space heating, water heating, cooking).

For thermal uses, based on the relative costs of each solution (including equipment and fuel costs), the model derives the energy mix between oil, gas, coal, electricity, district heat, bioenergy and H2/PtX. This process takes into consideration the existing equipment and their lifetime.

The model also includes an endogenous development for distributed solar panels (both PV and heaters) based on cost competitiveness and technological maturity.

Road transport – private vehicles:
The following assumptions have been derived from historical values and projections from VTT:
— number of private vehicles, i.e. cars & motorcycles;
— average annual kilometres per car;t
— otal private vehicle traffic in passenger-kilometre and vehicle kilometre (a constant occupancy rate per vehicle of around 1.6 passenger per car was assumed over the period);
— efficiency of new cars, per vehicle category.

Given the total number of cars, vehicle traffic, and the characteristics of each technology, the model calculates the share of each technology in the fleet, based on relative costs (equipment and fuel). Then, it derives the energy consumption by fuel.

Road transport – Freight:
The following assumptions have been derived from historical values and projections from VTT:
— number of light & heavy trucks;
— average annual kilometres per truck;
— total freight traffic in ton-kilometer per truck category (a constant load per truck of around 0.7 ton per light truck & 7.2 ton per heavy truck was assumed over the period).

Model calculations are similar to those for private vehicles.

Rail transport:
The Rail transport activity (passenger-kilometres and ton-kilometres) is endogenously derived from the GDP evolution, as well as the Road transport traffic evolution, both for passenger and freight. Based on these activity drivers, the model computes the total required energy demand. This energy demand is met by the different fuels depending on their relative costs and maturity, taking into account the rigidities associated to existing equipment lifetime.

Industrial sector:
The industrial sector is divided into four subsectors: chemicals, steel, non-metallic minerals and other industry. Main drivers in the industry sector are the evolutions of the value added of each subsector, except for steel, for which a trajectory for physical

production is assumed and used as the main activity driver. Based on these activity drivers, an energy price effect and energy efficiency gains, the model calculates projections for total energy consumption.

Based on the relative costs of each solution (including equipment and fuel costs), the model derives the energy mix between oil, gas, coal, electricity, district heat, bioenergy and H2/PtX. This process takes into consideration the existing equipment and their lifetime.

Since the POLES-Enerdata model does not cover every individual industrial branch and the associated precise technologies, benchmarks and roadmaps have been used to verify and adjust the results, which allowed to take into consideration specificities of the Finnish industrial context.

Agriculture & LULUCF emissions:
Population and GDP are the main drivers for the Agricultural energy consumption. As with the buildings sectors, the total required energy consumption is projected, and a competition process based on the relative costs between fuels is used to derived the energy mix.

LULUCF net GHG emissions are assumed to be constant at -21 $MtCO_2e$ (historical level).

Non-energy agricultural emissions are derived from Statistics Finland (historical data) & from VTT for forecast values. Main sources of emissions are farm animals, farmland fertilizers and cultivation, and manure.

Power sector:
The power module of the POLES-Enerdata model relies on two main sub-modules:

- a capacity planning module that calculates future power capacity needs based on the evolution of base and peak demand, and allocates the necessary capacity additions between technologies based on their relative costs and technological maturity;
- a dispatch module allocating the electricity generation based on installed capacities and the competitiveness of technologies (relative marginal costs of production), and ensuring that electricity generation matches the total demand of electricity at each step of the load curve. A simplified load curve representation (1 average summer day and 1 average winter day, by 2-hour steps) is used.

Assumptions for nuclear capacity evolution are: Olkiluoto 3 available for full operations in 2022, no additional plants commissioned before 2035, and after that the development is based on economic competition with other technologies.

Assumptions for wind capacities are onshore wind potential corresponding to 160 TWh and 21 TWh for offshore wind (based on Fingrid study). The capacity factors (from Forsman et al. 2021) are the following: onshore 34.2% and offshore 42%.

Finally, assumptions for solar potential are: 11 GW for centralized PV, 5 GW for distributed PV (based on Fingrid study), and a capacity factor of 11% (from ENTSOE).

B. Compass Lexecon power dispatch model

The European Power Market Model developed by Compass Lexecon (CL) is implemented in the commercial modelling platform Plexos® Integrated Energy Model. This modelling platform is most commonly used in the European electricity industry by utilities, regulators and transmission system operators. Plexos® allows finding solutions quickly using advanced optimisation procedures considering a large number of variables and complex constraints of transmission network and power plants. It also provides a flexible and user-friendly interface allowing testing multiple scenarios, to perform stochastic sampling and optimisation, and to present the results in a graphical form.

B1 European power plants database

CL has developed a European power plants database. It contains technical specificities (e.g. power plant types, capacities, efficiencies) of all European thermal plants and is used as the basis of the power dispatch model.

The database is regularly updated to include the latest announcements from plants operators, utilities and regulators.

It is completed by a range of scenarios on decommissioning dates for existing plants, commissioning dates for current and future projects, and projection on renewable developments.

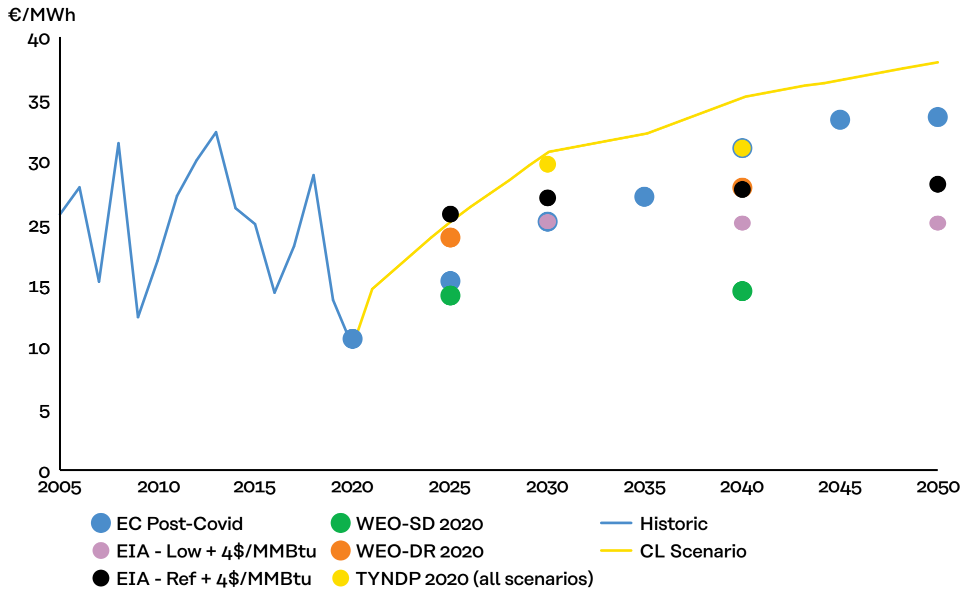
B2 European power market assumptions

The CL European Power Market model runs on a set of key inputs developed in-house. For the forward price assessment, a consistent set of assumptions based on public data as well as on CL's European expertise has been used. The power dispatch model uses:

- Demand projections. CL's long-term power demand projections in European countries are derived from a combination of GDP growth (based on the assumptions aligned with Sitra for usage in Enerdata's POLES model), policy effectiveness, and the expected technological change. In the reference case, the uptake of energy efficiency measures drives down electricity demand, but the electrification of the transport and heat sectors (together with GDP growth) offsets this reduction.
- Supply projections. These are based on climate and energy policies and technology development cost. In particular, future capacity mix scenarios in European countries are based on the existing thermal plants retirement or mothballing based on released publication, energy policies or economic modelling (including Large Combustion Plants Directive (LCPD) and Industrial Emissions Directive (IED) decisions), existing Low Carbon technologies retirement or life extension based on current and future energy policies, new thermal plant capacity scenarios based on economic modelling and new Low Carbon technologies scenarios based on future energy policies.
- Transmission projections. Based on the ENTSO-E data and CL's expertise on European power market, a transmission database referencing historic NTCs and future interconnection projects has been created.
- **Commodity and carbon price projections**. Commodity prices are one of the main determinants of the Short Run Marginal Cost (SRMCs) of most power generators, and thus a primary driver of wholesale power prices. We have developed internal scenarios based on publicly and privately released data

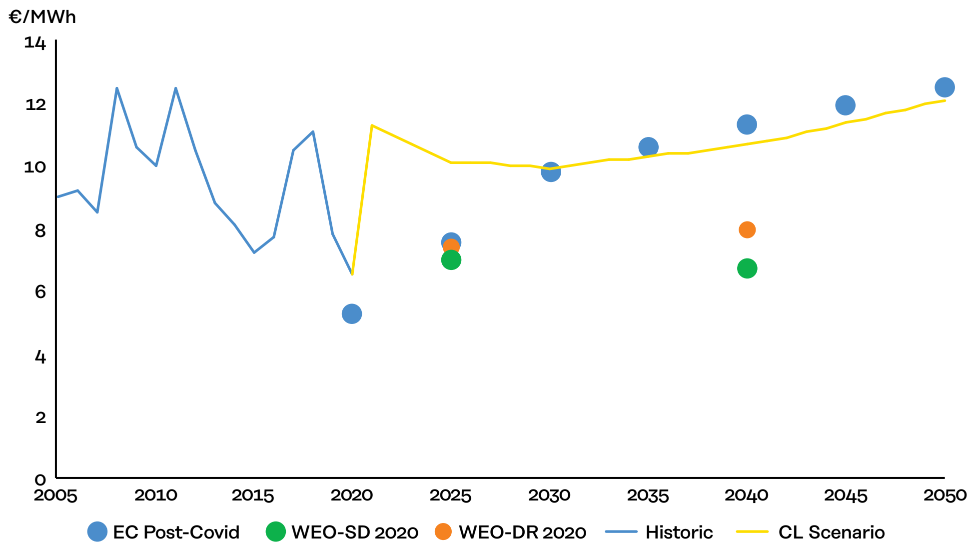
from IEA's World Energy Outlook and EIA's Annual Energy outlook projections. Commodity price projections are regularly reviewed to account for latest changes in energy regulation. See the gas and coal price assumptions in Figure 78 and Figure 79, respectively. The carbon prices used (Figure 80) reflect the European Commission's EUCO3232.5 scenario as well as imposed carbon price floors.

Figure 78: Gas prices assumption (CL Scenario) with multiple benchmark [€/MWh]



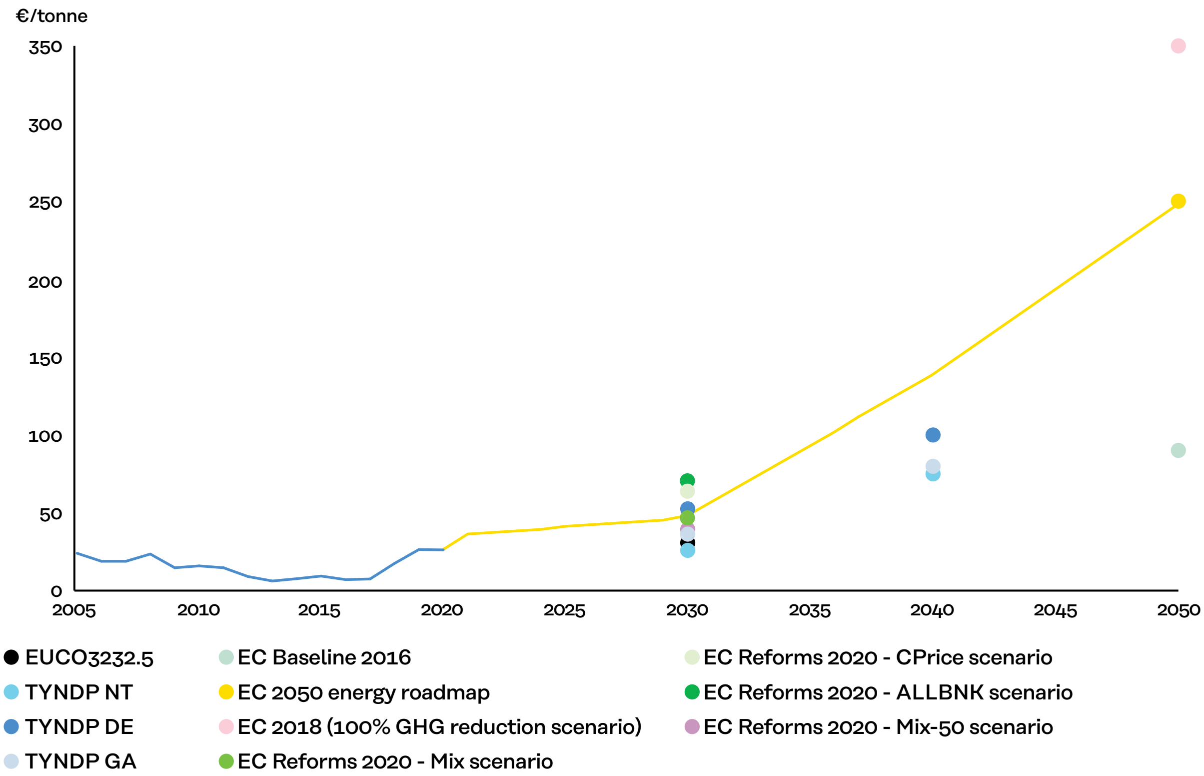
Source: Compass Lexecon scenario based on the sources listed in the legend

Figure 79: Coal price assumption (CL Scenario) with multiple benchmarks [€/MWh]



Source: Compass Lexecon scenario based on the sources listed in the legend

Figure 80: CO_2 price assumption (CL Scenario) with multiple benchmarks [€/tCO_2]



Source: Compass Lexecon scenario based on the sources listed in the legend

Each scenario is internally consistent and represents a plausible combination of assumptions on the considered variables.

B3 Geographic scope of the model

In conjunction with these proprietary datasets, CL has developed a European power dispatch model. It covers the EU-28 countries as well as Switzerland, Norway, the Balkans and Turkey. Countries beyond this geographic scope are modelled at an aggregate level. The geographic scope of the model is shown in Figure 81.

Figure 81: CL's European Power Market model

B4 Price calculation

This model uses a detailed bottom-up methodology: the supply from flexible thermal power plants is modelled to meet the demand net of the supply of must-run renewable generators. The dispatch is determined to minimise the costs of generation in the North-West Europe while satisfying the unit commitment constraints of generators as well as the flow constraints over the European transmission network. The model uses the zonal transmission network representation that matches with the price zones currently implemented in Europe and the commercial transmission boundaries.

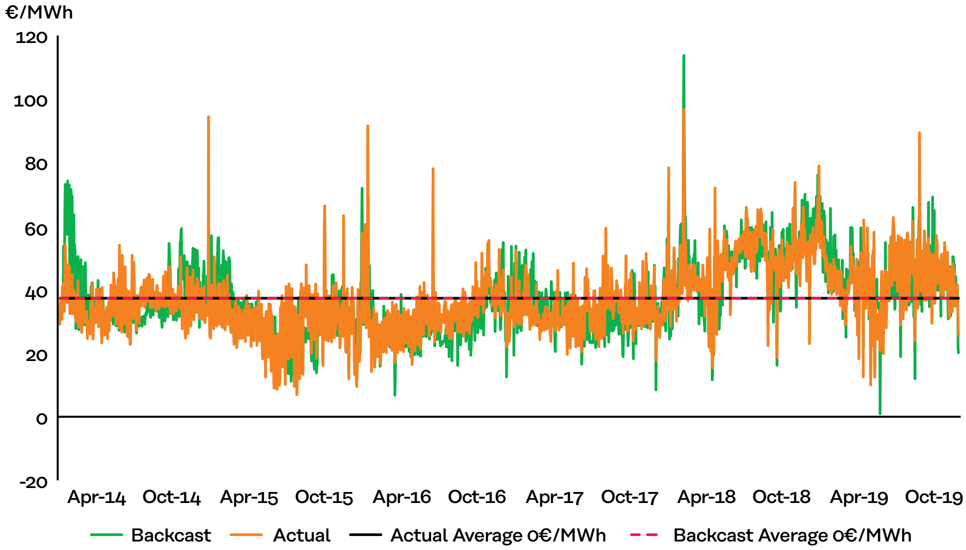
The model calculates the price in each price zone as the marginal value of energy delivered in that zone based on the simulated bids of flexible generators. In reality these bids closely follow the estimated short-run variable cost of power generation. Therefore, the estimated clearing prices correspond to the marginal cost of electricity. Such estimation of electricity prices based on the marginal cost is reasonable when the capacity margin above the demand is high and there is high competition between generators to serve the demand.

B5 Back-casting calibration

Our model has been calibrated with respect to the historical price profiles (including Nordpool prices in Finland) observed in several European countries. Back-casting is a process by which we use our model to forecast prices over a historic period and then compare to the actual prices observed over the same historic period. The closer the modelled results to the actual results, the greater comfort we can draw that our model will produce reliable forecasts over the future.

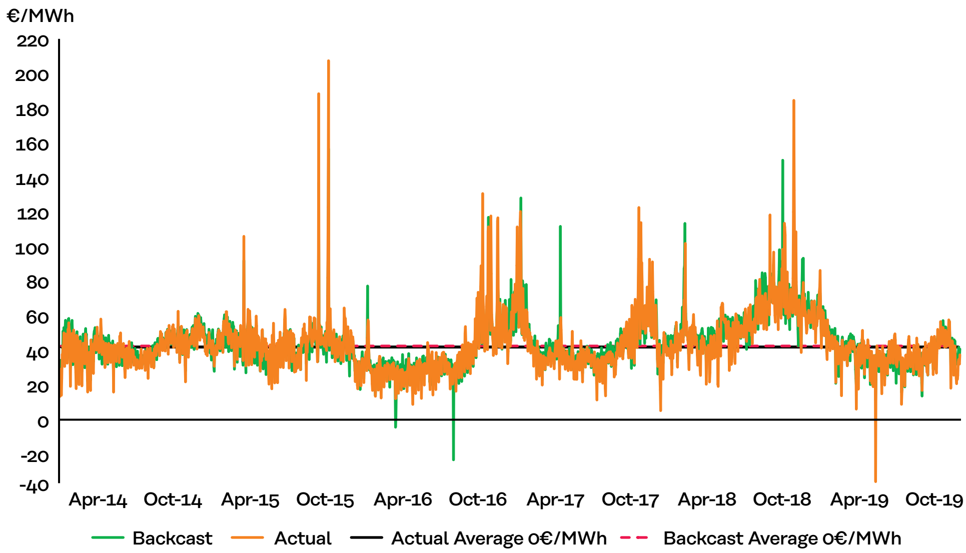
For example, the figures below show the results of the back-casting calibration of the prices calculated by the model against the realised wholesale prices in Finland (Figure 82) and Germany (Figure 83).

Figure 82: Back-casting calibration – Finnish historic and modelled prices (2014-2019)



Source: Compass Lexecon

Figure 83: Back-casting calibration – German historic and modelled prices (2014-2019)



Source: Compass Lexecon

B6 Renewable power generation modelling

Given the impact of renewable variability on future power system, we have developed specific methodologies to represent and forecast wind and solar production and model hydro flexible generation. The model also includes pumped storage modelling and has the flexibility to model on site storage. The renewable power forecast methodologies are completed by an in-depth understanding of the economic impact of renewable production on power prices.

B6.1 Wind – Power production

Following extensive analysis on the impact of wind variability on future power systems, for multiple clients such as TSOs, interconnection operators and European utilities, a specific wind model – the "CL Hybrid wind model" – has been developed. It combines:
- wind manufacturers theoretical power curve applied on historic re-calibrated wind speed data collected from weather stations across Europe; and
- historic wind power production.

This combined methodology strengthens the wind modelling capability as it goes beyond wind turbine manufacturers' data and uses historic technical performances at the heart of the "wind speed to power converter" algorithm. The methodology is derived from research papers on the statistical difference between theoretical wind power output and realised output.

B6.2 Solar – Power production

As solar technical performances are continually improved, solar production with great details has been modelled to include future technical improvements and technologies.

Besides using historic solar production, a dedicated methodology to model the impact of future technical improvements, such as capturing diffuse solar irradiation has been developed.

As for wind modelling, we collect irradiation data from weather stations scattered around Europe and convert the irradiation values into power values by using a statistical analysis on the relationship between average solar irradiation and national solar production. This relationship captures the inverter efficiency and diffusion coefficient.

B6.3 Wind & solar bids in wholesale market

To capture the fatal characteristic of renewable generation, the wind and solar production as a must-run generation have been modelled. Existing and under construction sites are allowed to bid negatively up to their renewable incentives level, creating occasionally negative prices.

Following work on the negative price impact and regulation, we have adapted our model to include a number of wind and solar sites vintages in order to accurately model the level down to which renewable plants will bid before being curtailed. This acknowledges that over time renewable generation will be merchant-only and won't have external incentives to create negative prices.

B7 Power dispatch model credentials

The CL's dispatch power model has been initiated internally by our experts to provide a robust and reliable source of market intelligence. Recognising that the best source of market insights stems from stakeholders, it has been developed collaboratively using our experts' insights and stakeholders' contributions.

Recently, the model has been fine-tuned on two principal components:
- CL team closely worked with utilities in the Nordic countries to further improve

their hydro modelling in order to understand the impact of increased flexibility sources on the power systems;
— CL team closely worked with TSOs and interconnector's developers to further improve their wind modelling in order to model the impact of increased variability on the power systems and cross-border flows.

Having been used extensively with clients, the European dispatch model is now widely recognised as a robust and reliable source of power market intelligence.

B8 Nordic and Alps hydro modelling

The model specifically focuses on an explicit modelling of the production flexibility provided by the Nordic and the Alps hydro reservoirs. Hydro production is one of the main determinants of the electricity prices in the Nordic region and one of the main sources of flexibility in the Alps. The hydro model is designed to dynamically replicate the seasonal optimisation performed by those producers. The modelling is based on two elements:
— hydro constraints, such as reservoir maximum levels and weekly natural inflows have been calibrated following extensive research on historic and future hydro data; and
— given the calibrated constraints, our dispatch model includes a state-of-the-art algorithm designed to calculate the "water value", i.e. the value of water held in storage. It then uses the water value of the hydro plants in the short-run optimisation.

This detailed approach further improves the dispatch model robustness, providing additional flexibility to the European power system.

B9 Pumped storage

Pumped storage facilities are the actual main source of storage on the European power systems. Our model includes a specific add-on to correctly account for this source of flexibility. It optimises its pumping and dispatch schedule on a weekly basis.

B10 On-site storage

Our model provides flexibility to model on site storage impact on power system. These additional features could be analysed in further sensitivities.

C Overview of external sources used to update the key knowledge on the demand and supply sectors in Finland

Table 18: External sources used to update the key knowledge on demand and supply sectors in Finland

Sector	Source	How utilised
Industry	Pöyry. (2020a). Roadmap to reach carbon neutral chemistry in Finland 2045. Pöyry. (2020b). Teknologiateollisuuden vähähiilitiekartta – Vaihe 2. Pöyry. (2020c). Tiekartta metsäteollisuudelle vähähiilistyvässä yhteiskunnassa. Gaia Consulting. (2020a). Vähähiilinen rakennusteollisuus2035 – Osa 2.	Update the latest demand forecasts and used technologies.
Transport sector	Koljonen et al. (2020). Hiilineutraali Suomi 2035. VTT. Data from the updated (2021) transport sector scenarios WEM and WAM from VTT. Andersson et al. (2020). Fossiilittoman liikenteen tiekartta. Ministry of Transport and Communications.	Assess the development of transport sector.
District heating	Afry. (2020). Finnish Energy – Low carbon roadmap. Historical data from Tilastokeskus.	Assess fuel uses and technological development.
Buildings and services	Gaia Consulting. (2020a). Vähähiilinen rakennusteollisuus2035 – Osa 2: Vähähiilisyydenmahdollisuuksien tarkastelu. Gaia Consulting. (2020b). Vähähiilinen rakennusteollisuus2035 – Osa 3: Vähähiilisyyden skenaariot. Gaia Consulting. (2020c). Vähähiilinen rakennusteollisuus2035 – Osa 4: Rakennusteollisuuden ja rakennetun ympäristön vähähiilisyyden tiekartta 2020 – 2035 – 2050. Pöyry. (2020b). Teknologiateollisuuden vähähiilitiekartta - Vaihe 2. Historical data from Tilastokeskus.	Assess the demand development of the sectors.
Biomass and LULUCF	Seppälä et al. (2019). Päästövähennyspolku kohti hiilineutraalia suomea. In addition, the above mentioned industry roadmaps. Historical data from Tilastokeskus.	Assess the current use of biomass and its development; Set the carbon sink target.
Energy and power sector	Koljonen et al. (2020). Hiilineutraali Suomi 2035. VTT. Forsman et al. (2021). Hiilineutraalisuustavoitteen vaikutukset sähköjärjestelmään. Prime Minister's Office. Fingrid. (2021). Verkkovisio. Afry. (2020). Finnish Energy – Low carbon roadmap. Historical data from Tilastokeskus	Inform the analysis and reflect on the results.

D Stakeholder interactions

Stakeholders in the workshops on modelling inputs and assumptions

— **Workshop 1:** VTT, Fingrid, Confederation of Finnish Industries (EK), Ministry of Economic Affairs and Employment (TEM), SSAB, Aalto University
— **Workshop 2:** TEM, EK, UPM, STEK, ELFI, Teknologiateollisuus (ET), Finnish Energy, Outokumpu, Energiavirasto, Kemianteollisuus, Atria
— **Workshop 3:** Elenia, Pohjolan Voima, Tampereen Sähkölaitos, Fortum, SYKE, Finnish Biocycle and Biogas Association, Helen, Nivos, Kymmenlaakson Sähköverkko, Savon Voima, Ilmatar, Finnish Clear Energy Association, Järvi-Suomen Energia
— **Workshop 4:** Fortum, HögforsGST, SULPU, Sympower, GreenEnergy Finland, Senaatti-kiinteistöt, Skanska, Grandlund, Kapacity.io, ABB, Suomen Omakotiliitto, e2m, Power Night Energy
— **Workshop 5:** Traficom, HKScan Finland, Finnish Energy, SKAL, LMV, Forest sector logistic companies, Logistics companies in Western Finland, VeloFinland, Finavia, Finnish Food and Drink Industries, Atria

Stakeholders in the workshops on modelling outputs

— Workshop 6: Technology Industries of Finland, Tampere University of Applied Sciences, Environment Ministry, Ministry of the Environment, Tampere University, Ministry of Economic Affairs and Employment, VTT, Siemens / Vibeco, Energy Authority
— **Workshop 7:** Kemijoki, Elenia Verkko, Finnish Energy, Fingrid, IBV Suomi, WPD Finland, Kymmenlaakson Sähköverkko, Ilmatar Windpower, Suomen Hyötytuuli, Suomen Lähienergialiitto, Järvi-Suomen Energia
— Workshop 8: Ministry of Economic Affairs and Employment, Traficom, Finnish Energy, SKAL, SULPU, Sympower, UPM, Fortum, Autoalan Tiedotuskeskus, Technology Industries of Finland, Wärtsilä, ELFi, Soletair Power, VTT, SSAB, Finnsementti, Fourdeg, HKScan, Ministry of Transport and Communications, Metsäalan Kuletusyrittäjät, Granlund, Kapcity.io, TietoEVRY, Fortum

Additional interviews

- Interview 1: SSAB
- Interview 2: Fortum
- Interview 3: Fingrid
- Interview 4: Gasgrid Finland
- Interview 5: TEM

Final stakeholder workshop

- Elinkeinoelämän keskusliito (EK), Elenia Verkko, Energiateollisuus, Energiavirasto, Fingrid, Finnish Biocycle and Biogas Association (Suomen Biokierto ja Biokaasu), Finnsementti, Fortum, Granlund, Ilmatar, Järvi-Suomen Energia, Kapacity.io, Kemijoki Oy, Kemira, Kymenlaakson Sähköverkko, Lämpöpumppuyhdistys SULPU, Liikenne- ja viestintäministeriö (LVM), Linde, Manifesto (on behalf of Ørsted), Metsäteollisuus, Ministry of Education and Culture (OKM), Savon Voima, Schneider Electric, Senaatti-kiinteistöt, SSAB, St1, Suomen Kuljetus ja Lobistiikka SKAL, Suomen Sähkönkäyttäjät (ELFI), Suomen Taksiliitto, S-Voima, Tampere University, Technology Industries of Finland (Teknologiateollisuus ry), Ministry of Economic Affairs and Employment (TEM), TietoEVRY, Traficom, Vasemmistoliiton eduskuntaryhmä, VTT, Wpd Finland

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