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Cross-sector flexibility, storage investment and the integration of renewables: Capturing the impacts of grid tariffs

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ABSTRACT

This article captures the role of electricity grid tariffs in the flexible electrification of district heating in the Nordic region at the horizon of 2050, in a situation of limited and optimal interconnections. Optimization of electricity and district heating systems is performed using the Balmorel energy systems model. Our results indicate that current volumetric tariffs substantially limit investment and flexibility from power-to-heat technologies and seasonal thermal storage in district heating. We also demonstrate how the additional flexible coupling of district heating enabled by adapted grid tariffs affects investment and generation in the electricity sector through a ratchet effect. We show that appropriate tariffs may result in up to 27% more electrification in district heating, 5% more wind and solar capacity investment in the electricity sector and up to 12% more wind and solar generation. Our results shed new light on the role of grid tariffs in the energy transition and inform policy-makers about the dynamics at play around tariff designs.

1. Introduction

1.1. General context

The European strategy to achieve a completely decarbonized energy supply by 2050 accelerates the reshaping of the existing energy mix. In 2020, for the first time in Europe, more electricity was generated from renewables than from fossil fuels. The double dynamics of the rapid increase in VRE and the progressive reduction of coal-based power plants (total European coal-fired generation has halved since 2015) is driving this turn of events, as observed in (Agora Energiewende, 2021). Against this backdrop, the Nordic countries have committed to decarbonizing their entire electricity, heat, and transport sectors to reach carbon neutrality in Norway and Denmark by 2050 and as early as 2045 and 2035 in Sweden and Finland respectively (Nordic Ministers, 2019). The share of renewable energy sources (RES) in the region already exceeds 35% of the total final energy demand (Eurostat, 2020), while the EU average is around 13.9%. In the electricity sector, this gap is wider due to different countries' available hydroelectricity and biomass resources and the ambitious policies for wind development. In Denmark, half of the demand for electricity is currently supplied by wind energy. Half of Swedish and Finnish domestic electricity production and the whole of Norwegian electricity consumption is provided by RES (e-Highway2050, 2015; Møller Sneum et al., 2018).

Electricity is rapidly becoming a vector for accelerating the transition across sectors. With about half of the Nordic heat demand supplied by district heating (excluding Norway, where individual electric heating predominates), heat electrification is pivotal to government engagement. Sector coupling between electricity and heat is the low-hanging fruit in the Nordic energy-transition pathway and a formidable way to connect the large thermal storage capacities capable of providing flexibility for wind and solar energy to the electricity system. At the same time, heat electrification is creating new challenges for future power systems. As an order of magnitude, the simple overnight replacement by wind energy of all coal, natural gas, and oil used to fulfil yearly European heat demand would result in a tenfold increase in current installed wind capacity (using heat demand and heat energy source values from (Persson and Werner, 2015; Danish Energy Agency, 2020). It is unlikely that any single source of energy will entirely replace fossil fuels in heat production. However, it is reasonable to expect a large part of this energy to be supplied by Variable Renewable Energies (VREs). Therefore, heat electrification cannot free itself from its flexible integration into electricity systems in order to limit capacity investments and ensure system reliability.

Recent studies focusing on modelling European decarbonization scenarios on a regional scale demonstrate the necessity of better

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representing the synergy effects across energy systems. The sum of these works, which are discussed further in the next section, assesses the potential for cross-sectoral flexibility to serve balancing needs and to limit capacity expansion on the electricity supply-side (Lund and Mathiesen, 2009; Hedegaard and Balyk, 2013; Pensini et al., 2014; Brown et al., 2018; Lund et al., 2019; Gea-Bermúdez and Graested Jensen, 2020), where the role played by interconnections in achieving environmental benefits is well established (Bergaentzlé et al., 2014). Furthermore, works assessing the business case of flexible power-to-heat (P2H) systems in district heating show that electricity grid tariffs have become an essential cost component in the competition occurring between electricity and other commodities such as biomass (Kirkerud et al., 2016; Møller Sneum et al., 2018; Bergaentzlé et al., 2019; Sandberg et al., 2019; Sneum, González and Gea-Bermúdez, 2021). However, the specific impact of grid tariffs on the flexible electrification of district heating has not been studied yet in the context of an interconnected region, where both sector coupling and electricity market coupling offers flexibility solutions.

1.2. Motivation

On the one hand, optimization tools offer essential guidance in deciding where, when, how much, and at what cost to invest in energy technologies. However, they usually only build on technical-economic data for equipment costs and performance, and fail including electricity grid tariffs, despite the increasing relative share of grid costs in the final electricity price (Hedegaard and Balyk, 2013). While this omission only marginally affects the optimum in an electricity system-only scenario, it becomes critical from a cross-sectoral perspective, where electricity competes with other energy commodities to deliver the same service, such as heat (Hansen et al., 2019). We argue that redesigned grid tariffs can support this multi-energy complementarity, which results from interdependencies and interactions across systems. On the other hand, recent works have assessed how different tariff designs affect the flexible use of electricity and incentivize thermal storage in district heating, though they fail to consider the effects of interconnections on system flexibility.

In this study, we explore how and to what extent a flexible electricity grid tariff can play a facilitating role in the flexible coupling of electricity and district heating in the context of interconnected systems and further increase VRE integration.

1.3. Contribution

This study combines energy-system integration at the regional level and electricity grid tariff analyses to quantify, compare and assess how different tariff designs influence flexible operation, P2H and storage investments in district heating. It contributes to the literature by adding the grid tariff costs to the short-term operation of electricity-heat systems and long-term investment decisions in an interconnected region. Our results disentangle the respective impacts of tariffs and interconnections on district heating flexibility in the Nordics at Horizon 2050 and stress the complementarity effects between market and sector coupling. Our results shed new light on how new tariffs affect investment choices in wind energy, solar PV, P2H technologies, and thermal storage technologies. The decomposition by country during the timeline adopted here also highlights the distributional effects across countries and energy stakeholders, which allows us to elaborate on policy pathways for flexible sector coupling.

The study is organized as follows. Section 2 presents a literature review pointing out the impact of tariffs on flexible sector coupling. Section 3 explains the methods, data, main assumptions and scenarios used in the article. Section 4 presents the results of the modelling. Section 5 summarizes the main findings and concludes by assessing policy implications and limitations.

2. Electricity tariffs for flexible sector coupling

2.1. District heating sector coupling for flexibility

Recent European literature shows an increasing interest in sector coupling resulting in a more systematic representation of other energy systems connected to electricity in long-term planning analyses. (Hansen et al., 2019) use 180 peer-reviewed articles published since 2004 to conclude that cross-sectoral analysis is becoming the state of the art in the context of 100% RES energy systems, driven by newly emerging opportunities for flexibility. Among the studies seeking to include the effects of electrification (Brown et al., 2018), demonstrate the synergy effects between transmission and the development of interconnection lines and sector coupling between electricity heat and transport on the integration of renewables (Gea-Bermúdez and Graested Jensen, 2020) also use the energy systems integration-interconnections scope to optimise short-term operation and long-term energy planning in north-west Europe, focusing on district heating and synthetic gas, and showing that the lowest system cost is reached when transmission expansions are associated with solid sector coupling. At the electricity-heat interface, (Pensini et al., 2014) demonstrate how seasonal thermal storage, such as pit storage, provides balancing services to absorb electricity surpluses from solar energy in the summer and serve the demand for heat in the winter. (Lund and Mathiesen, 2009) show that the full coupling of Danish district heating to the electricity system can technically support a 100% RES-based energy system in 2050, building essentially on wind and biomass. Finally (Chen et al., 2020), warn that competitive effects may arise from transmission expansion on sector coupling when both serve VRE flexibility.

2.2. Grid tariffs for VRE flexibility

The question of how current electricity grid tariffs affect energy systems is receiving growing attention from the sector, which sees currently dominant volumetric tariffs as an obstacle in achieving future decarbonized energy systems (CEER, 2020; Eurelectric, 2021). The motivations driving tariff revisions are country-specific, but two main arguments prevail. First, they are said to limit flexible behavior by the end-users in masking or distorting flexibility signals by either failing to reflect grid congestion when they occur or by distorting wholesale price variations and hindering appropriate responses from the demand-side (NordREG, 2015; Pérez-Arriaga and Knittel, 2016). Second, in the context of growing distributed RES, volumetric tariffs are said to pose the risk of users going off-grid, resulting in the reallocation of network costs to passive users and potentially creating a financial risk to utilities (Wood et al., 2016; Barbose and Satchwell, 2020; CEER, 2020). These two arguments ultimately stem from the lack of cost reflectiveness with volumetric tariffs, which allows network cost recovery based on the withdrawn kWh, whereas the costs faced by grid operators are predominantly fixed and stranded. Another theme is how tariffs can also satisfy fairness objectives in the allocation of network costs among users (Farrell, 2018; Gautier and Jacqmin, 2020; Schittekatte and Meeus, 2020), but because we limit the application of new tariff schemes to (large) district heating operators, we consider equity concerns to be beyond the scope of this article.

2.3. How grid tariffs affect district heating electrification and flexibility

From a sector-coupling perspective, overlooking the grid tariff fails to take into account the substitutability between electricity and other energy sources across energy systems. Volumetric tariffs have been considered a major obstacle to the flexible electrification of energy sectors by (Skytte et al., 2017; Bergaentzlé et al., 2019; Sneum, González and Gea-Bermúdez, 2021; Knezović et al., 2017; Andersen et al., 2019; Gunkel et al., 2020; Kirkerud et al., 2016; Sandberg et al., 2018).

(Kirkerud et al., 2016) tested alternatives to a volumetric tariff in district heating, including a real-time volumetric tariff, and showed that up to 17% of inflexible heat-only boilers could be replaced by P2H providing flexibility for wind integration. They further show that time-based tariffs trigger flexible operation by electric boilers in response to spot-price variations. However, the method used fails to take into account network cost recovery. Besides, the time-based adjustments of the grid tariff follow VRE fluctuations and therefore diverge from the mandate given to national regulatory agencies in setting up utilities' tariff schemes. In (Bergaentzlé et al., 2019), alternative tariff structures for flexibility that meet grid cost-recovery requirements are applied in Danish district heating. The study shows that applying a tariff design based on capacity costs rather than current volumetric tariffs supports a more flexible use of P2H and longer operating hours, with positive effects on heat supply costs and CO_2 emissions and without new risks for the grid operator.

In this article, we depart from the studies cited above by adding current network tariffs on top of the electricity price in the base case scenario and testing a hypothetical grid tariff that removes the volumetric charge from the cost per unit of MWh consumed in district heating while satisfying grid cost recovery objectives. Therefore, the tariff tested with the district heating operators is revenue-neutral for the grid operator. We stress that the tested tariff does not aim at suggesting an optimal tariff structure from the point of view of allocative efficiency, nor does it reflect the costs of the network in their spatial and temporal dimensions. Instead, this study assesses to what extent flexibility is hindered by current volumetric tariffs in the Nordic region and elaborates on how this translates into missed technology development in the electricity and district heating sectors.

3. Methodology

3.1. The optimization tool

The present study utilises the Balmorel energy system model using partial equilibriums to perform the analysis (Wiese et al., 2018) (http://www.balmorel.com/). The objective function in Balmorel minimises system costs (C^{Sys}) (1), allowing for optimised short-term dispatch and long-term investment in the heat and electricity sector assuming inelastic demand (Gea-Bermúdez and Pade, 2020).

$$\min C^{Sys} = \sum_{Y} DF_Y W_Y \left[\sum_{A,G} \left\{ C^{g_{inv}}_{Y,A,G} + \sum_{T} \left(C^{fuel}_{Y,A,G,T} + C^{O\&M}_{Y,A,G,T} + T^{ems}_{Y,A,G,T} + T^{prod}_{Y,A,G,T} + GT^{network}_{Y,A,G,T} \right) \right\} + \sum_{R,R'} \left\{ C^{trans_{inv}}_{Y,R,R'} + \sum_{T} C^{trans}_{Y,T,R,R'} \right\} \right] \quad (1)$$

The sum of all costs is taken over the years (Y), and is discounted with the discount factor DF and a sizing weight factor W. The costs from all generators (G) are then summed in all areas (A). Long-term investment decisions are represented by the investment variable $C^{g_{inv}}_{Y,A,G}$. Running expenses of generators such as fuel cost $C^{fuel}_{Y,A,G,T}$, O&M cost $C^{O\&M}_{Y,A,G,T}$, emission taxes for CO_2, NOX, and sulfur $T^{ems}_{Y,A,G,T}$, taxes on electricity and heat production $T^{prod}_{Y,A,G,T}$ and network grid tariffs $GT^{network}_{Y,A,G,T}$ are summed on an hourly (T) basis. Transmission lines connect two adjacent regions (R) and (R'). The costs of investment in capacity extensions are represented by $C^{trans_{inv}}_{Y,R,R'}$ and the operational cost of transmission lines $C^{trans}_{Y,T,R,R'}$ are summed every hour.

Details on the design, development, and applications of Balmorel are described in (Wiese et al., 2018). Fig. 1 shows the structure of the Balmorel tool.

The simulation period covers the decades from 2020 until 2050. It assumes a regime of 24 h a day, three days a week, from seven representative weeks per year, thus reflecting the yearly pattern and combinations of variable renewable energy production and energy consumption to reduce computational time. The model runs with predictability limited to two decades to optimise the current years concerning future developments.

The transmission system is represented by a flow-based model using Power Transfer Distribution Factors developed in (Gunkel et al., 2020), which provides a robust representation of the links between investment in transmission grid capacities and physical flows and commercial exchanges. The model does not represent the distribution system (low voltage grid). Consequently, all P2H technologies in district heating considered in the model are deemed to be connected to the transmission system. Distribution system tariffs are therefore not part of this study.

The spatial reference covers the Nordic countries, the Baltic States, the United Kingdom, and Central European states (Fig. 2). The scope of this study is the Nordic countries, and the results we present are for this area. We refer to the other countries in this study as "the rest of Europe" unless otherwise specified.

Balmorel is a partial equilibrium model which implies the limitations described here. At first, representation of the energy system is limited due to ongoing efforts to extend towards other sectors and computational complexity. The model does not react to dynamics outside the model boundaries. This includes, e.g., the response of input parameters like electricity and heat demand that rise and fall based on price changes. Furthermore, input parameters can show sensitivity to the results, and the linearisation of dynamics might only represent interactions in a simplified manner. However, the simplification helps to maintain a solvable model. The optimization was run on a 15 core 150 GB Ram server on an HPC with a computational time of approximately 28–42 h due to the large geographical and temporal size and the many technology options. The model is open-source, uses the programming language Gams, with CPLEX as the solver, and is available on Github.[1] Sensitivities are tested in several studies with the same model version (Hedegaard and Balyk, 2013; Brown et al., 2018; Chen et al., 2020; Gea-Bermúdez, Graested Jensen et al., 2020; Gunkel et al., 2020; Gunkel et al., 2020).

3.2. Main assumptions

The costs and technical data are based on (IEA, 2016a), while energy resources and technology cost developments are based on (IEA, 2016c). We assume a steadily increasing CO_2 cost, from 65 €/tCO_2 today to 130 €/tCO_2 in 2050, following the estimates of (Nordic Energy Research / IEA, 2016; IEA, 2018), and we calibrate the model so that a fully carbon-neutral electricity and heat sector is achieved by 2050, in compliance with the Nordic countries' targets. The EU population is projected to increase over the coming decades following the calculations in (IEA, 2016b). It is assumed that the legally binding targets for the share of RES in energy consumption are met by 2020. Nuclear and coal power plants under construction are included, but it is assumed that these technologies are not renewed after being phased out. The phase-out decision is based on the authors' perceptions of political decision-making at the time of writing. Future investment in bioenergy power plants results from market conditions and CO_2 prices, and is limited by the availability of biomass resources. We assume that hydropower is already fully deployed and remains constant. The costs associated with the final use of electricity also include grid tariffs. (Kirkerud et al., 2016; Sandberg et al., 2018).

In this study, the term 'heat sector' refers to district heating. Over a thousand different heating technologies have been exogenously installed or are available as investment options. Table A.1 in the Appendix summarizes the cost of the most frequently chosen options. The entire data input of the model, including all heating technologies and fuel prices, is also available on Github. Residential heating is not included as such but instead is considered to be aggregated with other

[1] https://github.com/balmorelcommunity/Balmorel/tree/F4R_Final_Model_002.

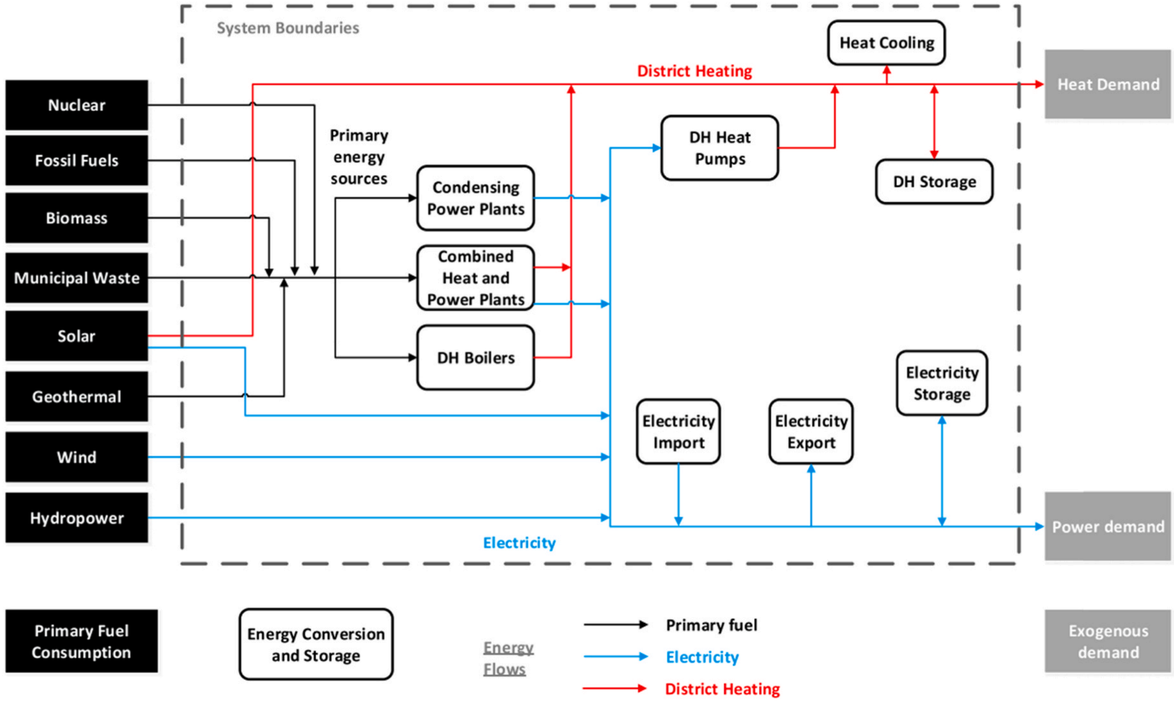

Fig. 1. Schematic of the modelling structure (Wiese et al., 2018).

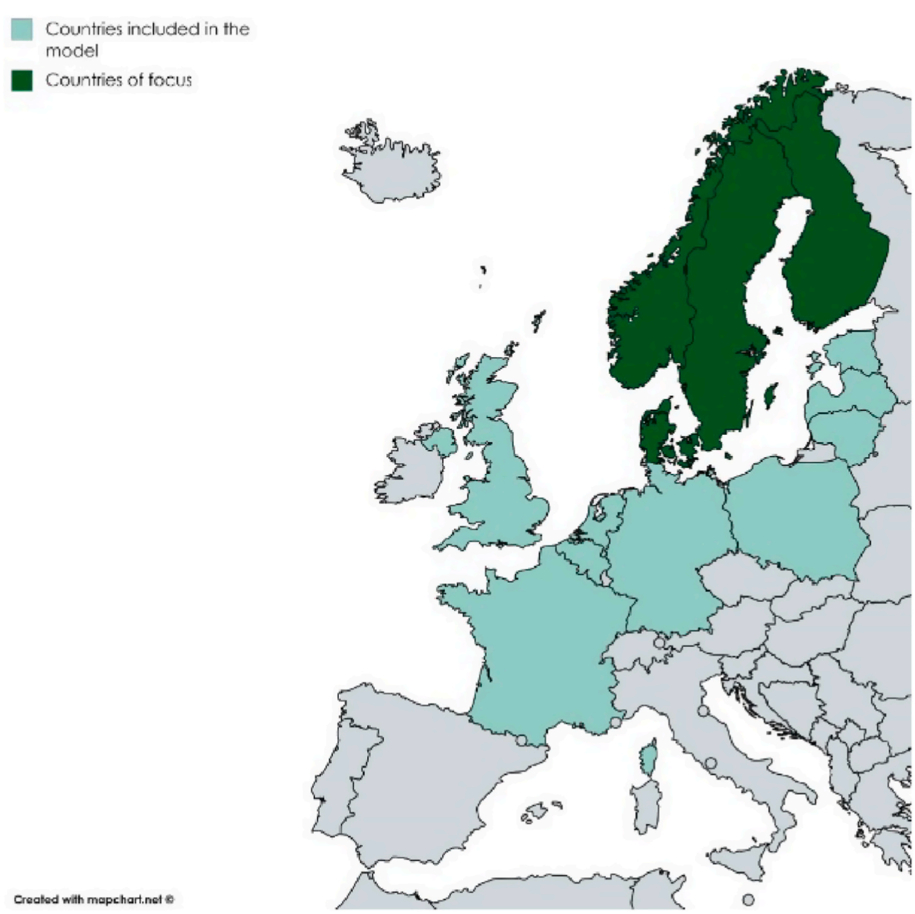

Fig. 2. Countries represented in the modelling.

Table 1
Electricity grid tariff structure in the Nordics paid by small to medium-sized industries like district heating.

Component	Denmark	Sweden	Norway	Finland
Capacity [€/MW]	368	1813	1307	2100
Volumetric [€/MWh]				
High	24	3	3	13
Mid	22	–	–	–
Low	17	–	2	6
Load demand [€/MW]	–	6984	–	3350
Subscription fee [€/MW]	–	30230	11984	–

Based on (Sandberg et al., 2018)

residential demand. Only district heating operators receive an additional incentive to adjust their loads with the new tariff. The modelled scenarios also assume the progressive growth of electric vehicles following country-specific pathways for smart charging presented in (Gunkel et al., 2020).

3.3. Current tariffs and capacity-based tariff

The model tests and compares the effects of two tariffs on district heating flexibility and the subsequent impact on VRE development.

The first tariff, hereafter called *volumetric*, corresponds to the tariff currently used in the modelled country and is shown for the Nordics in Table 1. Current tariffs have several components. The fixed capacity, load demand and subscription fee are paid on the basis of the installed capacity. The fixed capacity and load demand charge are paid every year based on the technological characteristics, and the subscription fee is paid once per year. The fixed charge is based on the installed capacity, whereas the highest recorded hourly power consumption determines the load demand charge during the year. The volumetric component is a simple energy-based charge added to the price of each consumed MWh in district heating.

The second tariff, hereafter called the *capacity tariff*, is designed to incorporate all the costs corresponding to the volumetric part in the capacity charge. Section 3.4 describes how the new capacity charge is calculated.

This design departs from what is economically optimal because it does not aim to reflect the grid cost in time. Economic theory holds that the optimal allocation of resources is driven by cost-reflective pricing. Accordingly, an efficient network tariff should impose a fixed charge reflecting the grid cost, sized to serve the peak load, a smaller unit-based energy charge reflecting the cost of losses and ancillary services derived from network use when the grid is not stressed, and congestion costs in congested periods. Whether this signal should be embedded in the energy or capacity component is open to discussion (CEER, 2020). The debate so far mainly entails finding an efficient balance between simplicity of implementation and understanding and level of reflectiveness.

This choice to reallocate the volumetric part to the capacity part is made because it allows us to reach the upper boundary of what it is possible to unlock in terms of flexibility. Thus we do not claim to design an optimal tariff from the point of view of economic and allocative efficiency, but to demonstrate the potential gains to be activated and to track their impact on VRE integration.

Table 2
Flexibility attributes of the scenarios.

	Interconnections	Tariff
BaU	Limited *	Volumetric
Connect	Optimal **	Volumetric
Policy	Limited *	Capacity-based
Combi	Optimal **	Capacity-based

(*) Entso-e TYNDP until 2030; (**) Entso-e TYNDP until 2030 then optimal investment.

3.4. Scenarios

We develop three scenarios that we compare to a base case or business as usual (BAU) scenario. The scenarios assess the impact of transmission expansion alone, the impact of the tariff on district heating alone, and the impact of the combination of both. Table 2 summarizes the scenario. All the scenarios apply to all the countries included in the modelling. Assumptions regarding CO_2 emission costs apply equally to all scenarios.

Scenario 1. business-as-usual (BAU) case. The transmission system is expanded until 2030 in accordance with the current ENTSO-E Ten Years Network Development Plan (TYNDP) (ENTSO-E, 2019), after which further investments are blocked. Electricity grid tariffs simulate current volumetric tariffs.

In scenario 2. Connect”. The model follows the BAU scenario until 2030 and endogenously determines the transmission capacities post-2030, based on minimisation of the overall system costs, including the transmission grid investments and operational costs, and the fixed and variable costs of electricity and heat production. In this scenario, European TSOs are assumed to be benevolent and investment in incremental capacity to be driven by market forces alone.

Scenario 3. Policy”. Builds on the BAU scenario with limited interconnection and introduces the capacity-based grid tariff design. Revenue neutrality for network operators is maintained by running the model twice, the first time assuming current national grid tariffs as in Scenario 1 shown in Table 1, the second time in redistributing the total sum of the collected tariff as a periodic capacity charge that ensures the utility's cost recovery. The following equation represents the new capacity charge:

$$GT_{Y,A,G}^{Capacity,Policy} = \frac{\sum_t^T GT_{Y,A,G,T}^{Volumetric,BAU}}{CAP_{Y,A,G}^{BAU}} \tag{2}$$

The yearly sum of volumetric grid tariff income $GT_{Y,A,G,T}^{Volumetric,\ BAU}$ in the BAU scenario for every single heating technology is divided by the installed capacity $CAP_{Y,A,G}^{BAU}$ and results in a yearly specific capacity charge $GT_{Y,A,G}^{Capacity,\ Policy}$ which replaces the volumetric charge $GT_{Y,A,G,T}^{Volumetric}$ in this scenario.

Scenario 4. “Combi”. Combines the Connect and Policy scenarios. The model optimally determines which option between interconnection and flexible sector coupling should be operated and invested in. As with equation (2) in the Policy scenario, a yearly capacity fee is calculated using the outcomes $GT_{Y,A,G,T}^{Volumetric,\ Connect}$ of the connect scenario.

4. Results

The results show the Nordic-wide impact of the new tariff on i) district heating electrification and ii) district heating flexibility, and the ratchet effect of this flexible electrification on iii) the electricity mix and iv) surplus wind generation in the years 2030, 2040, and 2050. The tariff impact is shown in the cases of both limited interconnection (in comparing the Policy scenario to the BAU) and optimal interconnection (in comparing the Combi scenario to the Connect scenario).

The Appendix compiles and summarizes the impact of the capacity-based tariff on the installed capacity and production (Figure A1 and A2) of each technology in both sectors in absolute and relative value and gives an overview of the electricity mix and the participation of each technology in electricity production (Figure A3 and A4).

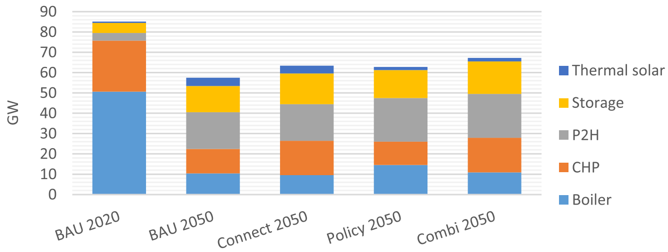

Fig. 3. Installed capacity in Nordic district heating by technology.

4.1. Up to 27% more electrification in district heating is achievable with adapted tariffs

Our results in the BAU scenario in 2050 indicate that a fossil fuel-free Nordic district heating system is possible with a district heating mix based on 54% of P2H capacities, including heat pumps and electric boilers, and thermal storage, 21% CHP capacities, 18% heat-only boilers and 7% solar thermal capacities (Fig. 3). Both the level of interconnections and the capacity tariff affect the total installed capacity in district heating and create export opportunities for CHPs to the rest of Europe, while the latter stimulates investment in P2H associated with thermal storage.

The capacity-based tariff results in about 20% more investment in P2H capacity in 2050 than in BAU, corresponding to 3.5 GW additional capacity, regardless of the level of interconnection. The new tariff also unlocks 7% more capacity investment in thermal storage, corresponding to an additional 823 MW–854 MW in the Policy and Combi scenarios respectively. This 27% reflects the P2H and thermal storage investment potential that is smothered by current volumetric tariffs in the Nordic countries.

CHPs capacity investment is closely linked to the market opportunities offered by cross-border links with the rest of Europe. Under the optimal interconnections scenario, Connect, total CHP capacity increases by 41% (4.8 GW) compared to BAU in 2050. Introducing the capacity tariff besides transmission grid expansion in the Combi scenario only marginally affects CHP investment (+1% compared to Connect). However, introducing the new tariff without expanding interconnections in the Policy scenario results in a 4% decrease in CHP capacities in 2050 compared to BAU.

Heat-only boilers fill the void left between CHPs and P2H. When CHPs expand with interconnections, total installed heat-boiler capacity shrinks, and when P2H replaces some CHP capacities, heat-only boiler capacity increases. In the scenario of limited interconnections and capacity tariff (Policy scenario), total installed heat-only boiler capacity increases by nearly 40% compared to BAU. (≈4 GW).

Finally, interconnections only marginally affect solar thermal technology in district heating, but the capacity tariff halves solar thermal capacity in BAU in 2050, plummeting from 4 MW to less than 2 MW in both the Policy and Combi scenarios.

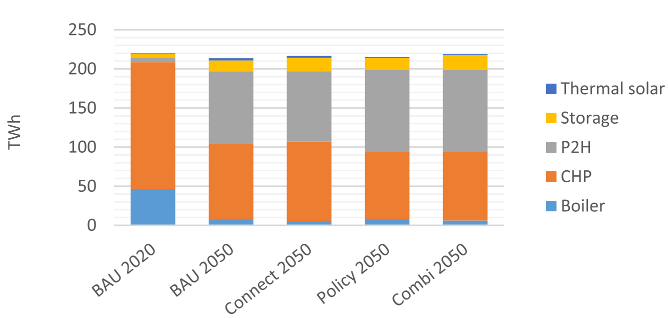

Fig. 4. Heat production in Nordic district heating by technology.

4.2. Up to 9% increase in P2H participation and new perspectives for long-term storage

In 2050, CHPs and P2H could be responsible for almost 90% of total heat production, regardless of the scenario. During the transition process, from 2020 to 2050 the output from cogeneration shrinks by 40%, declining from 161 to 97 TWh, while the production from heat pumps and electric boilers is multiplied by 16, jumping from 6 to 91 TWh in BAU (Fig. 4).

The positive variation in generation shown in Figure A.2 reflects the effect of the capacity tariff on the flexible use of the P2H installations combined with storage. An extra 14 TWh to 17 TWh of heat is generated by these two aggregated technologies in 2050, corresponding to an 8%–9% increase (Policy and Combi respectively) in the total 2050 mix compared to BAU.

The new tariff provides additional incentives to invest in short- and long-term storage, of which two-thirds will already be installed and operating in the 2030s in all the scenarios. Breaking down investment into short-term and long-term seasonal storage shows significant growth potential for seasonal heat storage, e.g., using water ponds (Fig. 5). This storage uncouples the heat demand from P2H operation, allowing it to follow the wholesale market-price signal during more hours throughout the year, mainly when the heat demand is low, as in summer. Long-term storage is the least used flexibility option in 2020 but becomes the dominant storage source in district heating from the 2030s. The capacity tariff increases long-term storage by 5% in both scenarios where it applies.

The results further indicate that short-term storage discharges actively, covering peaks in heat demand in winter, thus offering some degree of substitution to heat-only boilers and CHPs in district heating. Here again, the capacity tariff stimulates short-term storage participation in increasing its production by nearly 15% in both Combi compared to Connect, and Policy compared to BAU.

The capacity tariff triggers flexibility from district heating, which amplifies the utilisation rate of wind turbines and reduces curtailing. The two following sections describe how the additional flexible electrification enabled by the tariff affects the electricity mix and penetration of VREs.

4.3. A respective wind and solar PV capacity potential of 4.8% and 2.5%

The results indicate that the Nordic electricity mix is based on average on a 10% thermal, 30% hydroelectricity, 60% VRE capacity mix in 2050 (Figure A.3).

The additional district heating electrification triggered by the tariff has no impact on the development of non-RES and hydroelectricity or on thermal plants. Hydroelectricity and condensing thermal capacities (nuclear power plants, waste incineration plants, peat-based plants) remain unchanged regardless of the scenario. All coal plants are decommissioned as early as the 2030s. Only the size of the interconnections affects natural gas capacities that operate slightly longer in the mix (until the 2040s), as they benefit from relatively higher market prices from the rest of Europe. The most recently built gas plants are kept as a backup in 2050.

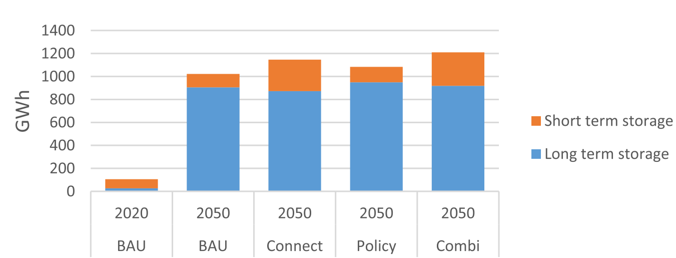

Fig. 5. Total installed storage capacity in Nordic district heating.

Fig. 6. Impact of the scenarios on additional installed capacity per technology in 2050 From top down: solar PV, wind energy and biomass.

The additional electrification of district heating results, however, in additional non-hydro renewable energy investment with both limited and optimal grid expansion (Fig. 6). On the one hand, the capacity tariff limits investment in biomass CHPs. In both scenarios where the tariff is introduced, the total CHP capacity is 4.5% lower in the Nordics in 2050. Two factors drive this loss. First, a direct substitution operates between CHPs and heat pumps with thermal storage in district heating, which reduces the operating hours of cogenerating plants. Second, the higher penetration rate of wind energy due to the extra flexibility in district heating pulls average electricity prices down further. The leeway for biomass energy profitability, therefore, shrinks in both markets.

On the other hand, the tariff triggers extra wind and solar capacity investment. Looking at wind development, optimal grid investment alone (Connect scenario) results in an increase of more than 50% of total Nordic wind capacity in 2050 compared to BAU. In the case of interconnection expansion, the capacity tariff in Combi results in a 4.8% increase in wind capacity (≈3.300 MW) at the Nordic level. Implementing the capacity tariff while restricting interconnection expansion post-2030 in the Policy scenario also supports wind development compared to BAU with +2.5% installed capacity in 2050 (≈1.100 MW). A closer look at the timeline indicates that half of the extra investment in wind capacity is made during the 2030s. Substantial differences in wind capacity investment also appear at the country level. In Denmark, Sweden and Finland, the share of wind capacity is relatively stable, regardless of the scenario, and accounts respectively for 95%, 62%, and 65% of total domestic installed capacities in 2050, while this share lies between 11% and 18% of Norwegian capacities.

Interconnection is also the main driver of solar PV investment in the Nordic region. Letting the model invest in new grid capacities increases solar PV capacity by 10% (≈3.500 MW) in 2050 compared to BAU. The combination of interconnection and capacity tariff results in nearly 900 MW additional PV capacity investment. In this Combi scenario, the results indicate that the tariff is responsible for a +2.5% increase in total installed capacity. A detailed analysis of the results shows that PV development reflects the indirect effect of the combination of two dynamics. When grid expansion is limited, the Nordics also have limited access to wind resources from the rest of Europe to compensate during low wind output periods in the region, and solar PV compensates. This effect intensifies with the new tariff, as it stimulates domestic P2H demand and therefore the need for additional electricity generating capacity.

Additional wind capacity finally drives grid investment up. The favorable wind potentials with high full-load hours (see Table A.2 in the Appendix) provide beneficial conditions for offshore hubs to export cheap electricity to the rest of Europe when the transmission system is expanded, and some cross-border links are further reinforced.

4.4. A potential of 15 TWh more VRE

The level of electricity generation by technology reflects the composition of the power mix, except for solar PV (Figure A.4).

Coal generation becomes marginal as early as 2030 and stops entirely in the 2040s. Natural-gas power plants are responsible for up to 0.7% and 0.4% of he total electricity production in the 2030s and 2040s, compared to 2% in the 2020s. Nuclear production decreases by 75% due to the non-renewal of decommissioned plants. This cumulated fall in generation is met by wind and marginally by solar PV production.

The extra flexibility in district heating enabled by the capacity tariff results in additional production from wind, solar PV, and biomass technologies (Fig. 7). Total Nordic wind production increases by 3.5%

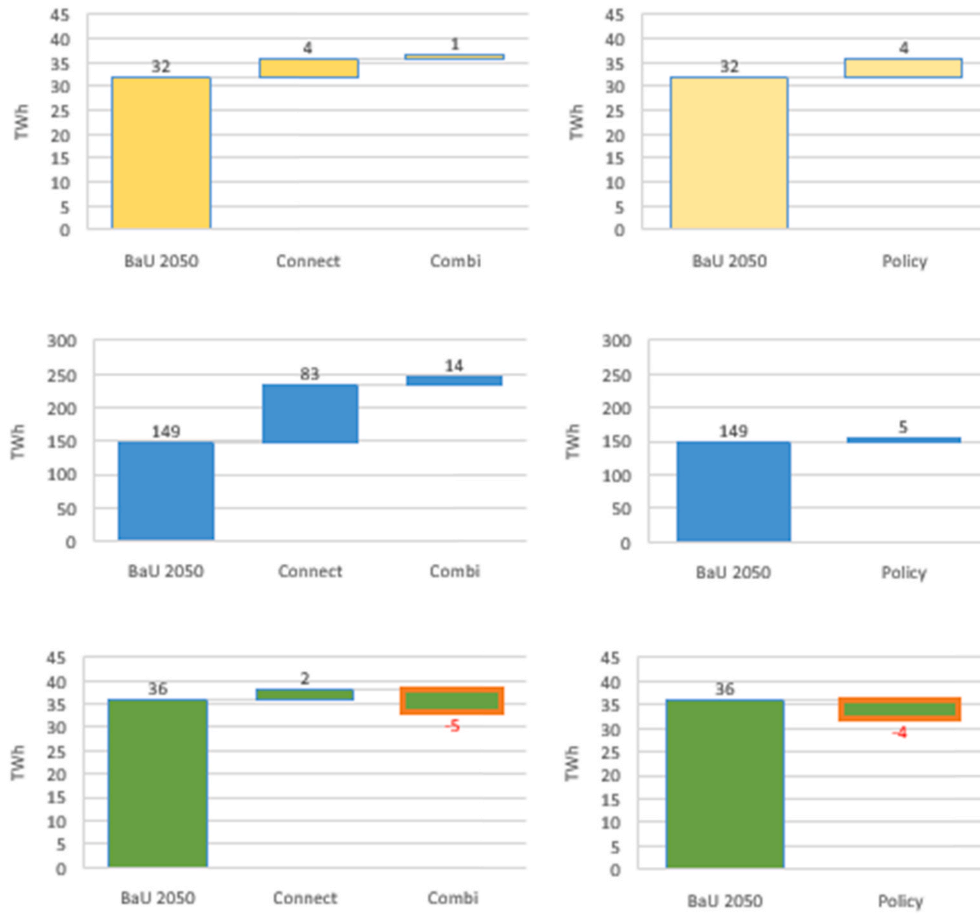

Fig. 7. Impact of the scenarios on additional production per technology in 2050 From top down: solar PV, wind energy and biomass.

(+5 TWh) in 2050 with limited interconnection (Policy vs BAU). Allowing investment in interconnection triples this production, bringing total wind energy generation from 233 TWh to 246 TWh (or +9% in the Combi vs Connect).

Solar PV generation marginally benefits from district heating flexibility, which results in a 12% (4 TWh) increase with limited interconnection (Policy vs B.a.U) and a 3% (1 TWh) increase with optimal interconnection (Combi vs Connect).

The 400 MW loss in biomass CHP capacity resulting from the new tariff results in a 10–14% (4–5 TWh) decrease in production. A yearly decomposition shows that the decline of CHP generation accelerates from the 2030s when the transmission grid is expanded.

5. Conclusion and policy implications

This article builds on past studies investigating sector coupling as a source of flexibility in a fossil fuel-free energy future, concluding that sector coupling accelerates VRE integration. However, this literature is unclear on how to activate sector coupling. On the other hand, literature using a narrower scope to address sector coupling focuses on the role and impacts of grid tariffs to accelerate electrification and support flexibility, but fails to capture the effects of interconnections. This study attempts to quantify how much extra flexible electrification we can obtain in district heating with the shift from current grid tariffs to a hypothetical capacity tariff and track back its impact on RES development focusing on the Nordic region. Our findings are aligned with the main conclusions in the existing literature regarding the beneficial effect of strengthening sector coupling for flexibility and VRE integration.

The way we model the tariff reveals the maximum additional investment in and operation of energy technologies in the electricity and district heating systems. Far from proposing an efficient network cost allocation structure for grid users or reflecting congestion effects to optimise future investment in capacity, it sheds new light on studies aimed at better estimating cross-sector synergy effects to achieve more flexibility. Ultimately, our findings distinguish the flexibility that results from more interconnections to the new tariff applied to district heating.

Our results indicate that switching from the current volumetric tariff to a capacity-based tariff could result in up to 20% additional investment in P2H and 7% additional investment in thermal storage in Nordic district heating. This extra capacity results in increasing P2H output and heat storage by up to 9%. This higher electrification of district heating, in turn, triggers up to 5% and 2.5% additional wind and solar PV capacity in 2050, which finally results in up to 9% and 12% more production from these two technologies respectively, depending on the level of interconnection. In particular, offshore wind potentials are expanded as their seasonally varying production peaks in winter, where electricity consumption of heat pumps is also at its highest (Potisomporn and Vogel, 2021). The new tariff also accelerates the exit of the CHPs with the highest marginal cost out of the market.

In terms of economic redistribution, a Nordic strategy building on either more interconnection or sector coupling will generate different results and affect the decarbonization pathway within the Nordics and in the rest of Europe differently. More interconnection with Europe pulls average Nordic electricity market prices up and keeps peak capacities, including using fossil fuels, in the mix longer. Better sector coupling through appropriate tariffs contributes to alleviating this effect, as it stimulates short-term storage in district heating, which contributes to replacing to natural gas-based production during the 2030s and 2040s.

Finally, the limitations in this study point to future improvements. First, the model only considers the cost variable in the development of

VREs. This study does not capture the restrictions on development reflecting, e.g., regulation or the lack of social acceptance, while (Bolwig et al., 2020) show that the latter can drastically limit wind-energy development in the Nordic region. The lack of social acceptance may also affect water-pond storage development, as their location usually collides with other urban development projects and limits the seasonal storage potential. Second, this study disregards the electrification and flexibility potentials associated with tariff designs from other P2X solutions in the region, despite substantial potentials (Gunkel et al., 2020).

Finally, this study points to avenues for further research. Primarily, it is necessary to explore to what extent network tariffs can contribute to unlocking flexibility gains beyond district heating through the electrification of transport modes and gas. Here again, many studies exist investigating both the impact of new tariffs on the flexibility of, e.g., battery charging, and the impact of the electrification of these uses on power systems. However, a synthesis of these works is yet to be carried out. While it is clear that tariffs have a role in accelerating the transition, the inclusion of this aggregate cost in the cost of electricity is too often omitted from energy-system models.

CRediT authorship contribution statement

Claire Bergaentzle: Conceptualization, Validation, Formal analysis, Writing – original draft, Writing – review & editing, Visualization, Supervision, Project administration. **Philipp Andreas Gunkel:** Methodology, Software, Validation, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix

Table A1
Technology options and costs

Technology group	Fuel type	Technology available for investments from year	Investment cost (M€/MW) (default value)	Annual operating and maintenance costs (k€/MW) (default value)	Variable operating and maintenance cost relative to output (€/MWh) (default value)	Variable operating and maintenance cost relative to input (€/MWh) (default value)	Economic lifetime (years)
COMBINEDCYCLE	NATGAS	2020	1.2740	28.7140		2.1991	25
COMBINEDCYCLE	NATGAS	2030	1.1760	27.2440		2.1815	25
COMBINEDCYCLE	NATGAS	2040	1.1270	26.3620		2.1697	25
COMBINEDCYCLE	NATGAS	2050	1.0780	25.4800		2.1560	25
BOILER	ELECTRIC	2020	0.0686	1.0486	0.8820		20
BOILER	ELECTRIC	2030	0.0588	0.9996	0.9800		20
BOILER	ELECTRIC	2040	0.0588	0.9506	0.9800		20
BOILER	ELECTRIC	2050	0.0588	0.9016	0.9800		20
BOILER	ELECTRIC	2020	0.1470	1.0486	0.8820		20
BOILER	ELECTRIC	2030	0.1372	0.9996	0.9800		20
BOILER	ELECTRIC	2040	0.1323	0.9506	0.9800		20
BOILER	ELECTRIC	2050	0.1274	0.9016	0.9800		20
BOILER	ELECTRIC	2020	0.8000	10.0000	0.0000		20
BOILER	ELECTRIC	2030	0.8000	10.0000	0.0000		20
BOILER	ELECTRIC	2050	0.8000	10.0000	0.0000		20
BOILER	FUELOIL	1970		10.0000	0.7600		20
BOILER	MUNIWASTE	2020	1.9027	79.7655	6.2155		25
BOILER	MUNIWASTE	2030	1.8140	74.7644	6.2304		25
BOILER	MUNIWASTE	2040	1.7622	71.2911	6.2452		25
BOILER	MUNIWASTE	2050	1.7104	67.8178	6.2601		25
BOILER	NATGAS	2020	0.0588	1.9110	1.0780		25
BOILER	NATGAS	2030	0.0490	1.8620	0.9800		25
BOILER	NATGAS	2040	0.0490	1.7640	1.0290		25
BOILER	NATGAS	2050	0.0490	1.6660	1.0780		25
BOILER	NATGAS	1970		9.5300	0.7300		20
BOILER	SHALE	1970		10.0000	0.7600		20
BOILER	STRAW	2020	0.6917	39.8961	1.0230		25
BOILER	STRAW	2030	0.6579	36.8271	1.0230		25
BOILER	STRAW	2040	0.6265	34.7812	1.0230		25
BOILER	STRAW	2050	0.5951	32.7352	1.0230		25
BOILER	WOOD	2010	0.5233	5.2984	1.2648		20
BOILER	WOOD	1970		14.0000	1.0700		20
BOILER	WOODCHIPS	2020	1.1924	37.9440	1.2648		25
BOILER	WOODCHIPS	2030	1.1341	36.7942	1.2648		25
BOILER	WOODCHIPS	2040	1.0800	35.6443	1.2648		25
BOILER	WOODCHIPS	2050	1.0259	34.4945	1.2648		25
BOILER	WOODPELLETS	2020	0.9540	33.1209	1.0037		25
BOILER	WOODPELLETS	2030	0.9074	31.1136	1.0037		25

(*continued on next page*)

Table A1 (*continued*)

Technology group	Fuel type	Technology available for investments from year	Investment cost (M€/MW) (default value)	Annual operating and maintenance costs (k€/MW) (default value)	Variable operating and maintenance cost relative to output (€/MWh) (default value)	Variable operating and maintenance cost relative to input (€/MWh) (default value)	Economic lifetime (years)
BOILER	WOODPELLETS	2040	0.8641	29.6081	1.0037		25
BOILER	WOODPELLETS	2050	0.8208	28.1026	1.0037		25
BOILER	WOODPELLETS	2020	2.2000	2.0000	1.0037		20
BOILER	WOODPELLETS	2030	3.0000	3.0000	1.0037		20
BOILER	WOODPELLETS	2040	3.0000	3.0000	1.0037		20
BOILER	WOODPELLETS	2050	3.0000	3.0000	1.0037		20
HEATPUMP	ELECTRIC	2020	0.7081	2.0231	2.0231		25
HEATPUMP	ELECTRIC	2020	0.9193	18.3860	0.0000		25
HEATPUMP	ELECTRIC	2030	0.8313	16.5279	0.0000		25
HEATPUMP	ELECTRIC	2040	0.7873	15.6966	0.0000		25
HEATPUMP	ELECTRIC	2030	0.6656	2.0231	1.8208		25
HEATPUMP	ELECTRIC	2050	0.7433	14.8653	0.0000		25
HEATPUMP	ELECTRIC	2040	0.6323	2.0231	1.7702		25
HEATPUMP	ELECTRIC	2050	0.5991	2.0231	1.7197		25
HEATPUMP	ELECTRIC	2030	0.5804	1.9600	1.6660		25
HEATPUMP	ELECTRIC	2050	0.5223	1.9600	1.5680		25
HEATPUMP	ELECTRIC	2020	0.6448	1.9600	1.7640		25
HEATPUMP	ELECTRIC	2030	0.5804	1.9600	1.6660		25
HEATPUMP	ELECTRIC	2020	0.6448	1.9600	1.7640		25
HEATPUMP	ELECTRIC	2030	0.5804	1.9600	1.6660		25
HEATPUMP	ELECTRIC	2050	0.5223	1.9600	1.5680		25
HEATPUMP	ELECTRIC	2050	0.5223	1.9600	1.5680		25
HEATPUMP	ELECTRIC	2020	0.6448	1.9600	1.7640		25
HEATPUMP	ELECTRIC	2020	0.6448	1.9600	1.7640		25
HEATPUMP	ELECTRIC	2020	1.4670	18.3860	0.0000		25
HEATPUMP	ELECTRIC	2030	0.5804	1.9600	1.6660		25
HEATPUMP	ELECTRIC	2030	1.3692	16.5279	0.0000		25
HEATPUMP	ELECTRIC	2040	1.2714	15.6966	0.0000		25
HEATPUMP	ELECTRIC	2040	0.5513	1.9600	1.6170		25
HEATPUMP	ELECTRIC	2050	1.1736	14.8653	0.0000		25
HEATPUMP	ELECTRIC	2050	0.5223	1.9600	1.5680		25
PIT	HEAT	2020	0.0014	0.0030	0.0000		20
PIT	HEAT	2030	0.0014	0.0030	0.0000		20
PIT	HEAT	2040	0.0013	0.0030	0.0000		20
PIT	HEAT	2050	0.0012	0.0030	0.0000		20
PIT	HEAT	2020	0.0004	0.0030	0.0000		20
PIT	HEAT	2030	0.0004	0.0030	0.0000		20
PIT	HEAT	2040	0.0004	0.0030	0.0000		20
PIT	HEAT	2050	0.0004	0.0030	0.0000		20
WATERTANK	HEAT	2010	0.0029	0.0084	0.0000		40
WATERTANK	HEAT	2010	0.0038	0.0000	0.0002		20
SOLARHEATING	SUN	2020	0.3099	0.0000	0.5586		30
SOLARHEATING	SUN	2030	0.2517	0.0000	0.5586		30
SOLARHEATING	SUN	2020	1.2143	9.5238	0.0000		25
SOLARHEATING	SUN	2030	1.0952	9.5238	0.0000		30
SOLARHEATING	SUN	2040	0.9881	9.5238	0.0000		30
SOLARHEATING	SUN	2050	0.8810	9.5238	0.0000		30
COMBINEDCYCLE	NATGAS	1955		12.0507		0.6968	50
COMBINEDCYCLE	NATGAS	2020	1.2740	28.7140	4.3120		25
COMBINEDCYCLE	NATGAS	2030	1.1760	27.2440	4.1160		25
COMBINEDCYCLE	NATGAS	2040	1.1270	26.3620	4.0180		25
COMBINEDCYCLE	NATGAS	2050	1.0780	25.4800	3.9200		25
COMBINEDCYCLE	NATGAS	2050	0.3840	9.6405	1.0970		30
COMBINEDCYCLE	NATGAS	2020	0.8624	28.7140	4.3120		25
COMBINEDCYCLE	NATGAS	2030	0.8134	27.2440	4.1160		25
COMBINEDCYCLE	NATGAS	2040	0.7987	26.3620	4.0180		25
COMBINEDCYCLE	NATGAS	2050	0.7840	25.4800	3.9200		25
COMBINEDCYCLE	NATGAS	2020	0.8624	28.7140		2.5441	25
COMBINEDCYCLE	NATGAS	2030	0.8134	27.2440		2.5108	25
COMBINEDCYCLE	NATGAS	2040	0.7987	26.3620		2.4912	25
COMBINEDCYCLE	NATGAS	2050	0.7840	25.4800		2.4696	25
BOILER	NATGAS	2010	0.0654	1.2101	0.4056		35
BOILER	NATGAS	2010	0.0654	1.2101	0.4056		35
COMBINEDCYCLE	NATGAS	2006		12.051		0.792	30

Table A2
Full load hours (FLH) by regions and wind production type

Country	Area type	Max FLH of Solar	Max FLH of Wind
FR	ON	1545	4117
FR	OFF		4434
BE	ON	1087	2871
BE	OFF		4704
DE	ON	1172	3239
DE	OFF		4803
DK	ON	1119	3718
DK	OFF		4993
EE	ON	1076	2778
EE	OFF		3920
FI	ON	970	2778
FI	OFF		3961
LT	ON	1076	2778
LT	OFF		4145
LV	ON	1076	2778
LV	OFF		3695
NL	ON	1098	3096
NL	OFF		4727
NO	ON	1012	4013
NO	OFF		5104
PL	ON	1130	2778
PL	OFF		4150
SE	ON	1066	3609
SE	OFF		4322
UK	ON	1119	4117
UK	OFF		5057
Country	Loc	Min FLH of Solar	Min FLH of Wind
FR	ON	1100	1523
FR	OFF		3133
BE	ON	970	2078
BE	OFF		3442
DE	ON	960	1548
DE	OFF		3753
DK	ON	950	2071
DK	OFF		3546
EE	ON	960	2176
EE	OFF		2535
FI	ON	860	2151
FI	OFF		2649
LT	ON	960	2095
LT	OFF		3131
LV	ON	960	2176
LV	OFF		2681
NL	ON	980	2076
NL	OFF		3566
NO	ON	798	1816
NO	OFF		3749
PL	ON	1010	2128
PL	OFF		3133
SE	ON	860	1957
SE	OFF		2968
UK	ON	880	2273
UK	OFF		3442

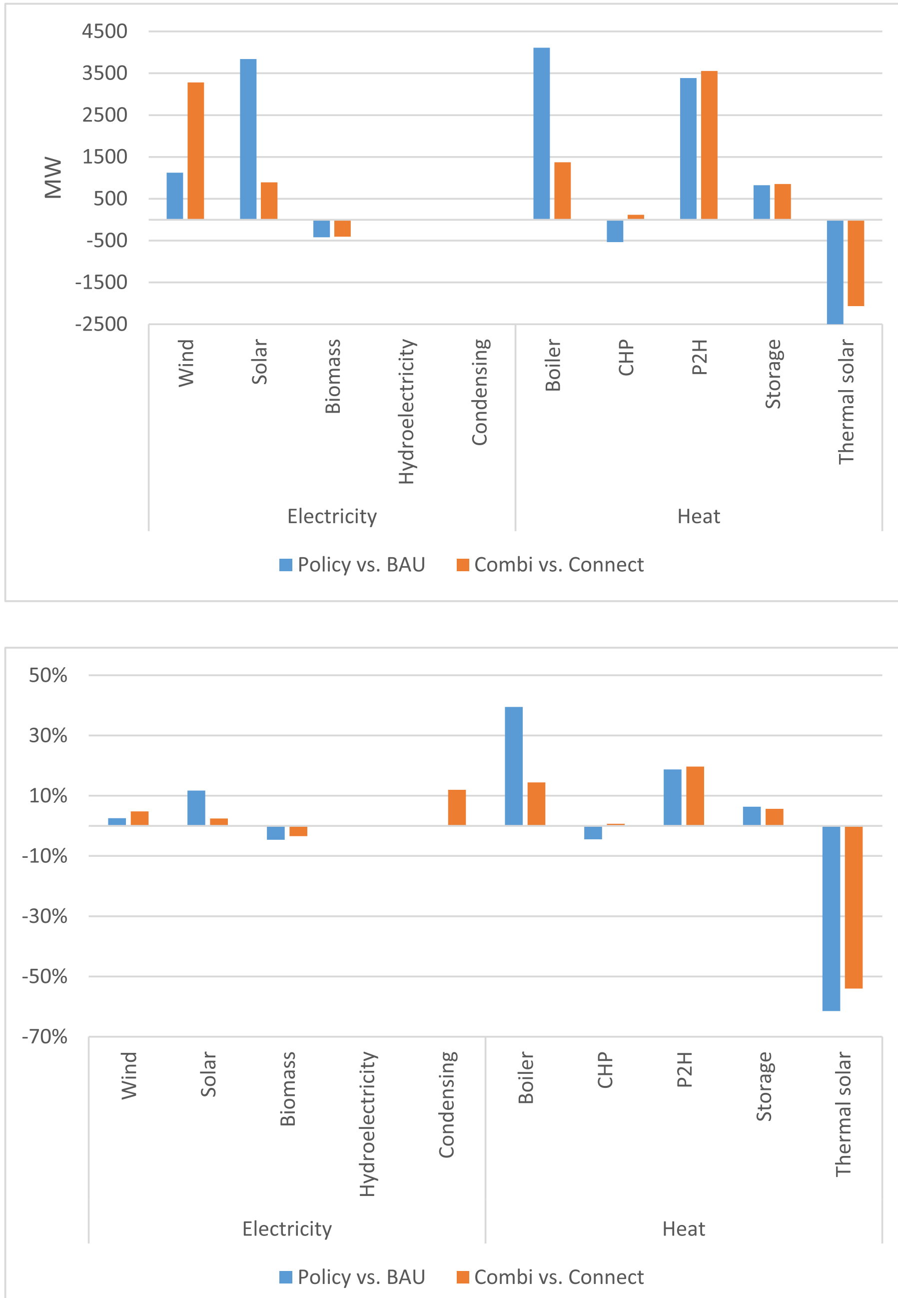

Fig. A1. Variation in energy technology capacity due to the tariff (in absolute and relative value 2050).

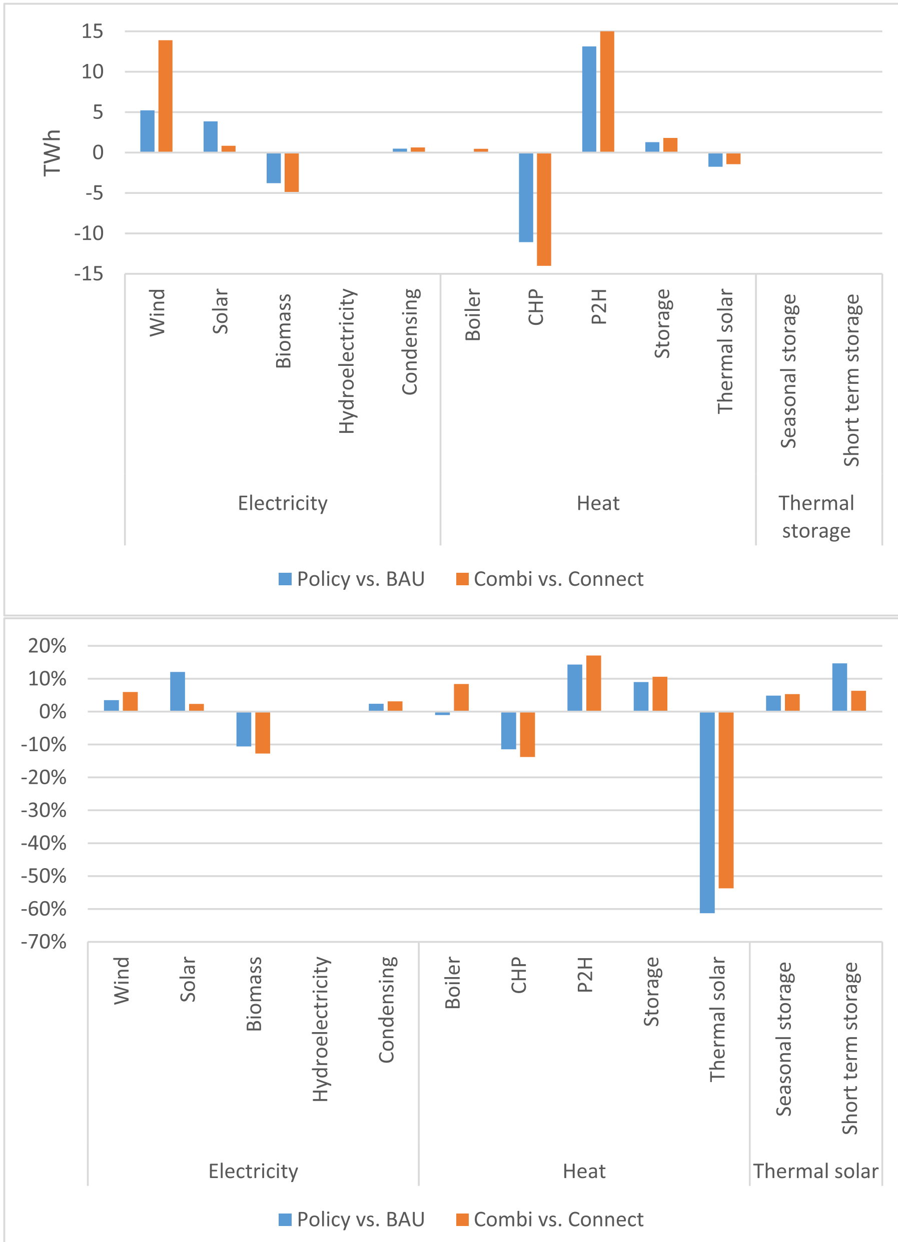

Fig. A2. Variation in energy technology generation due to the tariff (in absolute and relative value 2050).

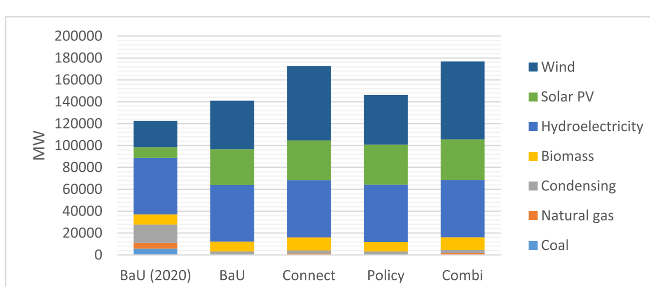

Fig. A3. Total installed electricity capacity in the Nordics (2050).

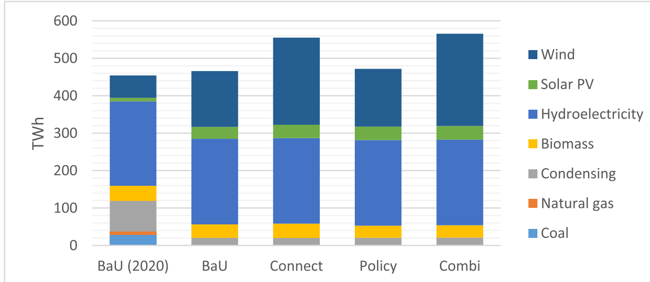

Fig. A4. Generation by technology in the Nordics (2050).

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