THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Supplying the Nordic electrification -Impact of local conditions

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Gothenburg, Sweden 2026

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Printed by Chalmers Reproservice
Gothenburg, Sweden 2026

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Abstract

The demand for electricity in the Nordic countries is expected to increase substantially over the coming decades, driven primarily by the electrification of the industrial and transport sectors. This thesis analyzes the transformation of the energy system, with a particular focus on how local conditions, such as weather patterns, demand magnitude and flexibility, and transmission grid characteristics shape cost-optimal electrification pathways.

The thesis consists of three papers, each addressing a distinct aspect of Nordic electrification. **Paper I** compares the cost-effective electrification strategies for six cities in Sweden, applying a previously developed linear optimization model for an urban energy system. Here, it is demonstrated that local city-specific characteristics significantly affect optimal system configurations only when electricity import capacity is stringently constrained. Under less-restrictive conditions, all cities exhibit heavy reliance on power-to-heat in district heating systems and substantial electricity imports. **Paper II** expands the scope to the Nordic region by examining the spatial optimization of renewable electricity generation using a newly developed model (EHUB Nordic) that represents the entire synchronous Nordic power system. With a highly spatially resolved geographic scope and a detailed representation of the transmission grid, this model enables analyses of how grid constraints and other local characteristics influence the electrification outcomes in the Nordic context. The results show that proximity to the demand for electricity strongly influences siting decisions for solar PV and onshore wind plants, whereas offshore wind deployment is primarily driven by the need for high annual production volumes to offset the higher capital costs. **Paper III** evaluates the system value of increasing transmission capacity through dynamic line rating (DLR). The findings indicate that, compared to static line rating, DLR enables greater solar PV integration and allows flexible hydropower to substitute for gas turbines by alleviating transmission bottlenecks. The value of DLR is also shown to depend strongly on geographic characteristics, including long transmission lines, low ambient temperatures, and the availability of high-quality wind sites in proximity to demand centers.

Overall, this work highlights the critical roles of local geographic and system-specific conditions in shaping cost-optimal outcomes from energy system modeling. Especially, four local characteristics emerge as particularly influential in shaping electrification outcomes in the Nordic region: transmission grid properties, weather conditions, the spatial distribution of electricity demand, and land availability. Effectively leveraging these local characteristics, through for example strategic siting of generation plants, urban sector coupling, and enhanced grid utilization, will be highly valuable when addressing the challenges and opportunities linked to the coming age of electrification in the Nordic region.

Keywords: *Energy system modeling, Electrification, Nordic region, Sector coupling, Renewable energy, Dynamic line rating*

List of publications

The thesis is based on the following appended papers, which are referred to in the text by their assigned Roman numerals:

- **I.** Bertilsson, J., Göransson, L., Johnsson, F.: Impact of Energy-Related Properties of Cities on Optimal Urban Energy System Design. Energies (Basel). 17, (2024). https://doi.org/10.3390/en17153813
- **II.** Bertilsson, J., Göransson, L., Johnsson, F.: Location, location, location: optimal placement of new electricity production in the Nordic energy system amidst large-scale electrification. Renewable Energy Focus. 56, (2026). https://doi.org/10.1016/j.ref.2025.100765
- **III.** Bertilsson, J., Göransson, L., Johnsson, F., Chen, P., Kuhrmann, L. Unlocking transmission capacity: The value and geographic specificities of dynamic line rating in the Nordic electricity grid. In manuscript.

Joel Bertilsson is the principal author of **Papers I–III** and performed the modeling and analysis for all three papers. Professor Filip Johnsson contributed with discussions and editing to **Papers I–III**, and Associate Professor Lisa Göransson contributed to the method development in **Papers I–III**, as well as with editing and discussions for all three papers. Associate Professor Peiyuan Chen and Luis Kuhrmann contributed with discussions and method development in **Paper III**.

Acknowledgments

As the rest of this thesis is quite long, I have tried to keep this section short. First of all, I would like to thank my parents for introducing me to the concept of energy. I especially remember choosing "Conservation of Energy" as the topic of a "scientific research project" in eighth grade. After that, I think my future career path was pretty much set in stone.

Thank you to my wife and family for showing me what is actually important in life. You make it very easy to forget about numerical difficulties, review comments, and infeasible modeling solutions. To my friends, thank you for your relentless support and for making my life a whole lot more fun.

To my supervisors at Chalmers, Lisa and Filip, thank you for always showing an interest in my work and making me feel like what I do actually matters. To all other colleagues at Energy Technology, thank you for creating a work environment that makes the 1h15m one-way commute to the office worth it.

Lastly, thank you, whoever you are, for reading this. Even if this is as far as you'll ever get in this thesis, I appreciate you taking the time.

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1 Introduction

Electrification has been identified by the International Energy Agency as one of the critical strategies for achieving substantial reductions in global CO_2 emissions [1]. Electrification entails the replacement of combustion-based technologies and processes, which typically rely on fossil fuels, with electrically powered alternatives. This transition is not confined to any single sector, but rather spans the entire energy system, encompassing industrial processes, transportation and buildings. As a result, global electricity demand is projected to increase sharply in the coming decades, marking the onset of what has been described as "a new age of electrification" [2].

Industry is expected to constitute the largest source of the anticipated increase in global electricity demand by Year 2050, owing to, as examples, the electrification of low- and medium-temperature heat demands and the expansion of scrap-based steel production [3]. In the residential and transport sectors, heat pumps are expected to replace combustion-based heating systems, while direct electrification is anticipated to dominate road transport. Importantly, while electrification of road transport and the building sector relies on mature and commercially proven technologies, industrial electrification is often associated with greater technical complexity, and therefore higher levels of uncertainty and economic risk [4].

A central pillar of the electrification transition is the large-scale deployment of low-cost renewable electricity generation to accommodate the anticipated increase in future demand. Between Years 2010 and 2024, the global weighted average levelized cost of electricity from onshore wind declined by 70 percent, while utility solar photovoltaic (PV) experienced a reduction of 90 percent in the same period [5]. Consequently, these technologies have become significantly less expensive than conventional fossil-based generation from coal and natural gas, which historically has constituted the backbone of the global electricity supply. A similar trend has been observed for battery storage investment costs, which have decreased by more than 90 percent over the same period [5].

From the Nordic perspective, the projected growth in electricity demand is expected to be driven primarily by the industrial and transport sectors, with some estimates indicating increases in the total electricity demand of more than 100% by Year 2050 relative to current levels [6]. Industrial demand for electricity is anticipated to increase for several key uses, including steel production, the petrochemical and fertilizer industries, and data centers. A substantial share of this growth, particularly in Sweden, Denmark, and Finland, is expected to be linked to hydrogen production via electrolysis, although the precise magnitude of this contribution remains highly uncertain [6].

The increasing demand for electricity, in conjunction with a growing share of variable renewable electricity (VRE) generation, introduces new operational challenges for a transmission grid that has historically been designed around dispatchable and centralized electricity production. The variability and intermittency of wind and solar resources necessitate more-advanced strategies for managing net-load fluctuations and maintaining system reliability. Storage technologies and demand-side flexibility are expected to play central roles in addressing these challenges, alongside the reinforcement of the transmission infrastructure and the efficient utilization of existing grid capacity. Moreover, local characteristics across the Nordic region, including weather conditions for VRE generation, transmission grid constraints, and land availability, will shape both the challenges and opportunities associated with the transition. Leveraging these geographic specificities in an effective manner will be essential for maintaining competitiveness in the emerging age of electrification, which the Nordic countries are now approaching.

1.1 Aim and research topic

This thesis aims to investigate the interplay between local energy system specificities, such as demand size and type, climatic conditions and grid bottlenecks, and the system-wide transition toward large-scale electrification in a Nordic setting. This is evaluated under conditions of strict constraints on fossil CO_2 emissions, concurrent with a projected substantial increase in the electricity demand.

To address this overarching research objective, the thesis examines electrification from three complementary perspectives: urban electrification; spatial localization of VRE production; and transmission capacity enhancement through dynamic line rating (DLR). Based on these perspectives, the research questions addressed in this work are formulated as follows:

> RQ1: How do differences in local conditions impact the cost-efficient electrification of cities in Sweden?
>
> RQ2: What are the key local factors influencing the cost-optimal placement of new electricity production in the Nordic energy system during large-scale electrification?
>
> RQ3: What value can the implementation of DLR offer in the Nordic countries, and how is this affected by geographic specificities?

These questions are examined throughout this thesis and in the three research papers included in this work. **Paper I** addresses RQ1 by investigating the cost-optimal strategy for meeting the future urban energy demand, with particular emphasis on the electrification of industries in urban regions and the heating sector. **Paper II** broadens the scope to the scale of the Nordic synchronous grid, addressing RQ2 by analyzing the spatial optimization of VRE generation assets. This includes accounting for both proximity to major load centers and site-specific meteorologic conditions that influence wind and solar photovoltaic (PV) potential. Finally, **Paper III** addresses RQ3 in that it explores the potential value of leveraging the existing transmission infrastructure through the integration of DLR and demonstrates how geographic specificities strongly influence its system-level benefits. By integrating these three perspectives, this thesis highlights the critical role of local conditions in shaping the broader electrification pathway.

1.2 Contributions of this thesis

This work advances the current knowledge through the distinct contributions of its three constituent papers and the overarching synthesis of the thesis. **Paper I** contributes novelty in utilizing measured data from multiple cities within a high-temporal-resolution model. It uniquely demonstrates the effects of city-specific characteristics on cross-sectoral coupling between electricity, heating, transport, and industry, an interaction that was previously largely unexplored.

Paper II presents a novel energy systems model that performs high-geographic-resolution optimization for the localization and sizing of both intermittent VRE and dispatchable generation units, accounting for both investment and dispatch costs. The methodological novelty lies in: (i) integrating a detailed spatial representation of local wind and solar conditions; (ii) creating a comprehensive representation of the region's dominant hydropower resources; and (iii) verifying the model results using a full AC power flow model of the same grid. The analysis provides a perspective that is missing in similar, previous modeling studies, by explicitly quantifying how local factors influence the siting of VRE.

The contribution of **Paper III** is twofold. First, building on the model presented in **Paper II**, it offers a unique perspective on how specific geographic characteristics impact the modeling output and economic value derived from DLR implementation. Second, the work adds methodological value by underscoring the critical necessity of incorporating a maximum voltage angle difference constraint into the optimization model formulation.

By synthesizing and framing the findings of these three papers, this thesis provides a holistic understanding of the complex relationships between local energy characteristics, grid infrastructure, and technology interplay, which are crucial for realizing the Nordic electrification pathway in a fossil-free and cost-efficient way.

2 Background and related work

This thesis examines electrification in a Nordic context from the following three perspectives: urban electrification shaped by local characteristics; spatial optimization of VRE; and the system impacts of transmission capacity enhancement through DLR. Given the breadth of electrification as a concept, the background focuses on previous research that is relevant to these specific areas, rather than on electrification in general.

2.1 Urban energy system modeling and electrification

Cities play a critical role in addressing climate change, as urban areas account for more than 70% of global annual greenhouse gas emissions [7]. Consequently, their contributions to achieving climate neutrality have been extensively examined in the energy systems literature. For example, Keirstead et al. [8] have conducted a comprehensive review of urban energy system modeling, highlighting the key challenges and opportunities related to model complexity, data uncertainty, and policy relevance. Additional reviews that have focused on urban energy-system modeling include that of Horak et al. [9], who emphasize spatio-temporal considerations, and Allegrini et al. [10], who focus on the simulation of urban- and district-scale energy systems.

However, a critical aspect that has received limited attention in the previous studies is how city-specific energy characteristics influence the optimal composition of an urban energy system. Lund et al. [11] have addressed this issue by examining the integration of high shares of VRE in two cities with markedly different characteristics: Helsinki and Shanghai. Their results highlight the importance of energy storage and flexibility in enabling high shares of local solar PV generation in Shanghai and wind power in Helsinki. Similarly, Liu et al. [12] have analyzed 28 cities in China to assess their potentials to eliminate fossil CO_2 emissions by Year 2050. By categorizing cities according to industrial structure and energy intensity, they conclude that while substantial emissions reductions are achievable, it is unlikely that all the considered cities can become fossil-free by Year 2050.

A major outcome from **Paper I** is the coupling of electricity and heating sectors in urban energy systems, demonstrating that integrating a higher share of electricity-based heat sources into district heating can be cost-efficient from the system perspective. Similar conclusions have been reported in the literature. For example, Arabzadeh et al. [13] have analyzed decarbonization pathways for the Helsinki area and shown that tighter coupling between the electricity and heating sectors provides a level of flexibility that enables higher shares of VRE, although inter-regional electricity trade remains necessary for a complete transition away from fossil fuels. Sorknæs [14] reaches comparable conclusions using the EnergyPLAN model to simulate future energy systems in Denmark and Austria, highlighting that heat pumps and electric boilers can efficiently reduce biomass dependence in the heating sector, while facilitating higher VRE integration without increasing curtailment. Likewise, Pensini et al. [15] have demonstrated that VRE-based electricity combined with heat pumps and thermal energy storage can provide a highly cost-effective alternative to conventional district heating systems that are based on incineration.

More recently, Javanshir et al. [16] have assessed the risks associated with electrified district heating in Helsinki, drawing on experiences from the exceptionally high electricity prices observed in Europe in Year 2022. Despite these challenges, the study concludes that transitioning from fossil-based heating to power-to-heat solutions can significantly reduce dependence on imported fuels, lower carbon emissions, and enhance energy security, while remaining cost-competitive.

2.2 Spatial resolution in energy system modeling and optimal location of VRE

In energy system modeling, the optimal spatial allocation of VRE has often been examined using spatially aggregated representations, with a lack of emphasis on physical transmission grid constraints and local characteristics [17]. Such studies have typically assessed the benefits of large-scale coordination of VRE deployment and enhanced grid interconnectivity across continents or multiple countries. For example, Brown et al. [18] have investigated the optimal VRE siting from a pan-European perspective, modeling each country as a single node and focusing on sector coupling and cross-border transmission. They conclude that while interconnecting countries helps to smooth generation variability, particularly from wind power, the largest system cost reductions arise from sector-coupling flexibility. Related studies have explored similar interactions between VRE and their optimal spatial distributions in other regions, including the Middle East [19], [20], South America [21] and North America [22], as well as various countries in Europe [23], [24], [25].

While these studies typically employ capacity-expansion models to analyze scenarios with high shares of VRE, they often rely on a relatively coarse spatial resolution. This type of modeling has two main implications: (i) it obscures the identification of optimal VRE locations by averaging capacity factors over large areas; and (ii) it reduces the impact of transmission bottlenecks within the electricity grid [26]. The effects of spatial resolution on model outcomes have been examined by Frysztacki et al. [26], who propose a methodology to isolate the influence of spatial detail in energy system modeling with high shares of VRE. Their results show that increasing the spatial resolution can raise the total system cost by up to 23%, primarily due to the emergence of transmission constraints that are not apparent at coarser scales. In addition, they observe substantial shifts in the relative shares of onshore and offshore wind power, with finer spatial resolution favoring onshore wind by enabling more-precise identification of high-quality sites. Overall, that study underscores the importance of high spatial resolution for robust technology selection, particularly in cases where transmission expansion is limited or prohibited.

Other studies that have employed a high spatial resolution in energy system modeling further illustrate the value of a detailed geographic representation. Fürsch et al. [27] have demonstrated this by analyzing European grid expansion using a model with 224 nodes across the continent. Similarly, Obermüller [28] has investigated the optimal placement of onshore wind by comparing wind energy valuations under nodal and zonal market structures. Using the PyPSA framework to model Germany with 575 nodes, that study shows that zonal pricing, whereby large areas are aggregated, can lead to suboptimal wind investment decisions, thereby increasing grid congestion and reducing the overall system value of wind power. The high spatial resolution adopted in these studies enables the capture of local variations in weather conditions, demand profiles, and grid connectivity, all of which play crucial roles in determining the optimal siting of distributed electricity generation technologies. A similar approach is employed in **Paper II** in this work, in that it optimizes the localization and sizing of distributed generation, including both VRE´s and dispatchable production units, using high geographic resolution. In addition, the modeling framework incorporates an explicit representation of the transmission grid, with results validated through the use of a full AC power flow model, as well as a comprehensive representation of hydropower, which is the predominant electricity generation source in the region.

The impact of spatial resolution in large-scale capacity expansion models has been further examined by Serpe et al. [29]. Using the ReEDS model, the authors have compared two levels of geographic resolution across two synchronous regions in the United States. Their results show that a higher spatial resolution significantly affects both the location and composition of new investments, particularly for onshore wind and the transmission infrastructure. However, Serpe et al. [29] also emphasize that a higher spatial resolution does not necessarily guarantee greater accuracy. In cases where the quality or availability of the data is limited, spatial disaggregation may introduce additional uncertainties and potential bias. Moreover, increased spatial detail entails a heavier computational burden. As a consequence, Serpe et al. [29] conclude that the value of high spatial resolution is highly context-dependent: it is strongly justified for analyses that are focused on VRE siting or transmission planning, whereas more-aggregated representations may be sufficient for examining broader, continental-scale trends.

2.3 Grid representation in energy system models and dynamic line rating

Transmission grid infrastructure can be represented in energy system models using a range of approaches that differ in terms of complexity, computational requirements, and data needs [30]. The simplest representation, often referred to as a 'pipe-flow', 'trade-flow', or 'net transfer capacity' model, limits the power flows based solely on line capacity constraints and the nodal power balance [31]. In this formulation, many physical properties of transmission lines, such as electrical reactance, are neglected. This simplified representation is straightforward to implement and enables fast solution times. As a result, the pipe-flow approach represents a very commonly used representation of transmission infrastructure in energy system modeling [32].

However, when the purpose of an energy system model is to analyze the effects of transmission grid bottlenecks, a representation that more accurately reflects the physical constraints of the grid is warranted [31]. To this end, a linearized approximation of AC power flow, commonly referred to as 'DC load flow' or 'linearized power flow', is frequently employed. This formulation relies on several simplifying assumptions, including small voltage angle differences between nodes, fixed voltage magnitudes across all nodes, negligible line resistance relative to reactance, and the omission of reactive power flows. Despite these simplifications, the DC load flow formulation captures the influence of line reactance, while retaining a linear structure that is suitable for large-scale optimization. Compared to simpler transport or pipe-flow representations, the introduction of DC load flow, as applied in the EHUB Nordic model used in **Papers II** and **III** of this thesis, has been shown to impact both the spatial localization of electricity generation and the resulting distribution of electricity prices [33].

The expansion of transmission infrastructure to facilitate higher shares of VRE has been identified as a key enabler of large-scale electrification [1]. However, the construction of new transmission lines is capital-intensive, time-consuming, environmentally challenging, and often faces public opposition. As a complementary measure, by leveraging the prevailing meteorologic conditions, DLR offers the potential for a rapid and cost-efficient increase in grid capacity with minimal additional environmental impact [33]. This approach, where transmission capacity is determined for each timestep based on ambient wind speed, temperature, and solar irradiance, is incorporated into the modeling framework in **Paper III**.

In the existing literature, research on DLR has largely focused on its interaction with wind power systems. This emphasis primarily arises from the positive correlation between wind power generation and available DLR capacity, as both benefit from higher wind speeds. Studies carried out by Wallnerström et al. [34] and Lee et al. [35] exemplify this line of research, demonstrating how DLR can enhance the integration of wind power by increasing transmission capacity during periods of high wind generation. However, relatively few energy system optimization studies have incorporated DLR within frameworks that rely on detailed representations of both transmission networks and meteorologic conditions across a wide geographic scope. In particular, models that simultaneously combine high temporal and spatial resolutions, historical weather data, and endogenous investment and operational decisions for generation assets are scarce in the literature.

A notable exception to this is the work of Glaum and Hofmann [36]. Using historical weather data for Germany and implementing DLR within the PyPSA framework to represent the demand, generation, and transmission infrastructure, they have shown that DLR can reduce the total system costs by approximately 5–7%, depending on the scenario assumptions. Their analysis demonstrates that the observed cost savings are primarily attributable to increased utilization of offshore wind power which, enabled by enhanced transmission capacity, can penetrate further into the system, thereby reducing reliance on solar PV generation and short-term storage.

3 Models

This section introduces the two optimization models employed in this thesis: the City model, initially presented by Heinisch et al. [37], and the EHUB Nordic model, developed as part of the present work and first described in **Paper II**. Since the primary methodological contribution of this thesis is embedded within the EHUB Nordic model framework, the following section will focus on this model.

3.1 Applied models in this thesis

The two models applied in this thesis, EHUB Nordic and the City model, are conceptually similar with respect to their overall objectives and structural design. Both are formulated as linear optimization models with the objective of minimizing the total system cost, which comprises annualized investment costs and operational expenditures. The operational costs account for variable components, such as fuel consumption and variable operation and maintenance (O&M) costs, as well as start-up costs and part-load efficiency penalties. For each timestep, the demands for electricity, heat and hydrogen must be satisfied for each modeled node. This includes both the historical hourly demand data (for electricity and heat) and the projected future demand arising from industrial electrification and the electrification of the transport sector. Both models determine the least-cost combination of production technologies, storage systems, and electricity imports required to meet this demand, subject to the constraints imposed on production capacities, conversion efficiencies, and meteorologic conditions.

The resulting output consists of the optimal investment capacities and time-resolved dispatch profiles corresponding to the most cost-efficient system configuration that satisfies all of the model constraints. The overall modeling process for both models is illustrated in Figure 1. Model components unique to the City model are indicated in blue, while elements specific to the EHUB Nordic framework are shown in orange. Full mathematical formulations of the applied models are provided in **Paper I** for the City model and in **Paper II** for the EHUB Nordic model.

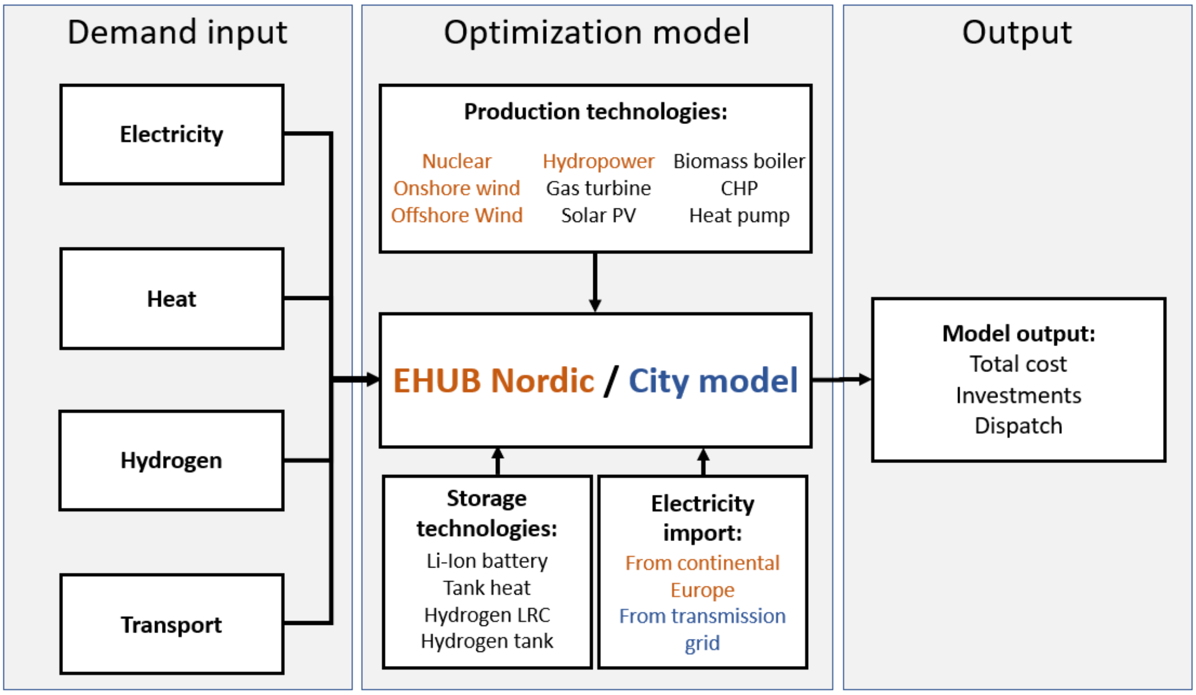

Figure 1. Overview of the model framework applied in this thesis. The demands for electricity, heat, hydrogen and transport are attributed to each city/node. The optimization model then identifies the cost-optimal technology mix that can meet these demands based on available production technologies, storage systems and electricity imports. Model components unique to the City model are indicated in blue, while elements specific to the EHUB Nordic framework are shown in orange. CHP, Combined heat and power; LRC, Lined rock cavern.

The fundamental differences between the two applied models relate to geographic scope and representation of the electric grid. While the City model optimizes the energy system for a single node, representing an individual city, the EHUB Nordic model encompasses 354 interconnected nodes, corresponding to all transformer stations within the Nordic synchronous grid operating at voltages of 220 kV and above. EHUB Nordic incorporates a broader range of electricity generation technologies, such as hydropower, wind power, and nuclear power, which are not deployable in any practical sense within an urban context and, thus, are excluded from the City model. Furthermore, the models differ with respect to their representations of electricity exchange. In the City model, electricity can be imported and exported from the transmission grid, limited only by a maximum import constraint, whereas in the EHUB Nordic model, electricity trade is represented through existing interconnections between internal nodes, as well as through exchange of electricity with continental Europe via existing DC interconnectors. The temporal resolution also differs between the two models: the City model operates at an hourly resolution, whereas EHUB Nordic employs a 3-hour timestep. In both cases, the modeling horizon spans one full year, with technology costs and demand projections assumed for Year 2050. The principal characteristics of the two models are summarized in Table 1.

Table 1. Comparison of the two linear optimization models applied in this thesis.

	City model	**EHUB Nordic**
Paper(s)	**I**	**II and III**
Syntax	GAMS	GAMS
Type of model	Linear optimization	Linear optimization
Model aim	Minimize total system cost	Minimize total system cost
Temporal scope	1 year, Year 2050	1 year, Year 2050
Temporal resolution	1-hour timesteps	3-hour timesteps
Geographic scope and resolution	One node representing one city in Sweden	354 nodes across the Nordic synchronous transmission grid (operating at ≥220 kV)
Energy carriers	Electricity, heat, hydrogen	Electricity, heat, hydrogen
Main outputs	Total system cost, investments and technology dispatch	Total system cost, investments and technology dispatch

3.2 The EHUB Nordic model

The geographic scope of the EHUB Nordic model is illustrated in Figure 2. The black dots represent the 354 nodes included in the model, each corresponding to a transformer station within the Nordic synchronous transmission grid. The geographic coordinates of these transformer stations are used as centroids for generating Voronoi cells that delineate the spatial boundaries of the modeled areas across the Nordic region. Consequently, each node is associated with a specific geographic area from which capacity factors and production profiles for wind and solar power are derived. The blue lines in Figure 2 denote high-voltage (≥220 kV) AC transmission lines connecting the nodes, based on grid data for Year 2023 from ENTSO-E [38], with assumptions regarding line impedances and number of conductors as presented by Hodel et al. [39]. In addition, grid expansion projects planned by the Nordic transmission system operators [40] up to Year 2040 are included in the modeling framework. The grid representation in EHUB Nordic is intentionally kept identical to that used in Hodel et al. [39], enabling the model outputs to be directly verified using the AC power flow model presented in that study.

The red lines in Figure 2 indicate DC connections, both within the modeled Nordic area and between the Nordic region and neighboring European countries. Electricity trade with continental Europe is modeled as bidirectional, allowing for both imports and exports.

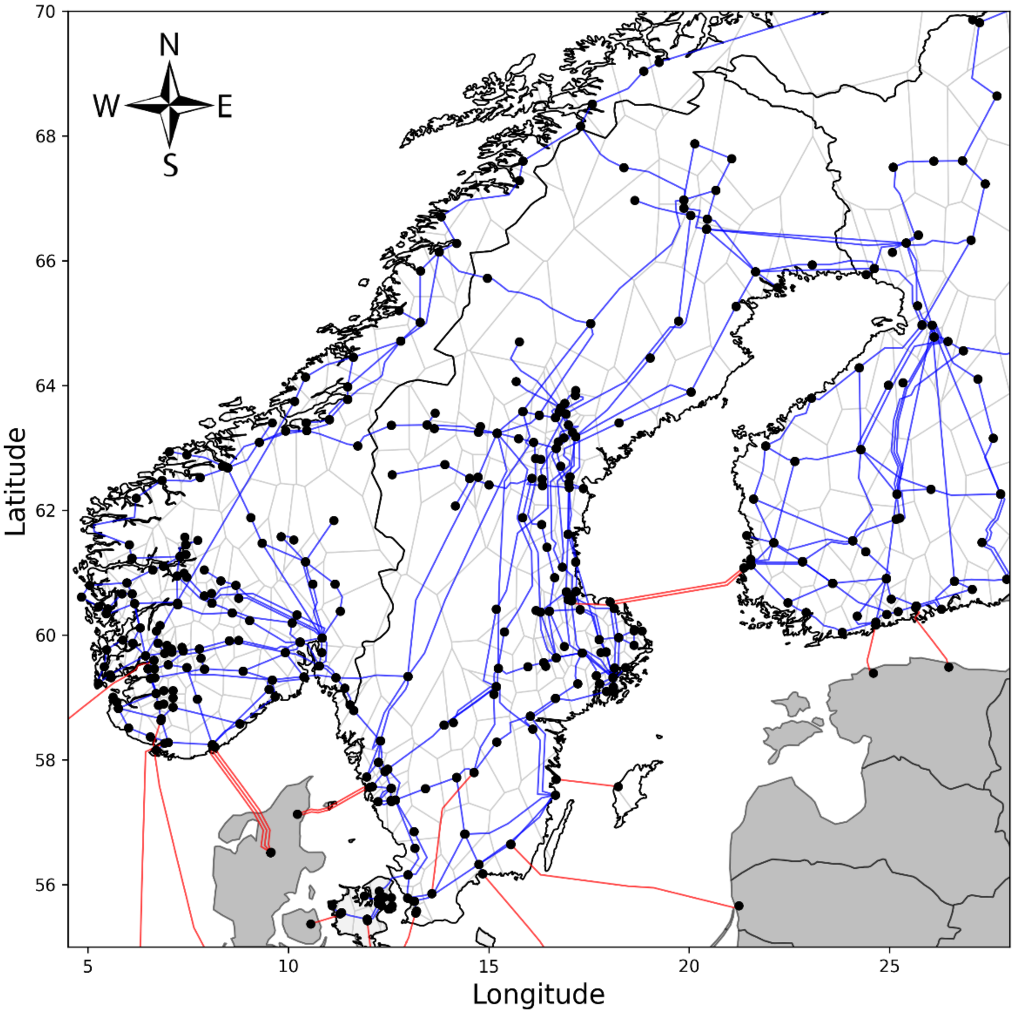

Figure 2. The geographic area to which the EHUB Nordic model is applied, illustrating the Voronoi-cells, transmission grid (blue lines) and DC-connections (red lines). The gray-colored lands indicate areas outside the modeled region.

The AC transmission grid (blue in Figure 2) is modeled using what is commonly referred to as the 'DC load flow approach' or 'linearized power flow' [41]. This method involves linearizing the non-linear equations that govern the full AC power flow by introducing the following simplifying assumptions:

- The voltage angle difference between nodes is small, such that sin(Δθ) ≈ Δθ and cos(Δθ) ≈ 0;
- The voltage magnitude is fixed at its nominal value (V = 1 p.u.);
- Reactive power flows are neglected; and
- Line resistance is considered negligible relative to reactance.

As a result, the active power flow between two nodes can be expressed as:

$$f_{t,n,m}^{trans} = B_{n,m} * \left(\theta_{t,n} - \theta_{t,m}\right) \quad \forall t, n, m \tag{1}$$

where $(f_{t,n,m}^{trans})$ denotes the active power flow between nodes n and m at time t, $(B_{n,m})$ represents the susceptance of the line connecting the nodes, and $\left(\theta_{t,n} - \theta_{t,m}\right)$ is the voltage angle difference between them.

This simplification is primarily adopted for the purpose of computational efficiency as it enables a linear formulation. Although the DC load flow formulation represents a simplification of full AC power flow, it provides a more-realistic characterization of transmission system behavior compared to the transport model, which is frequently used in energy system modeling and permits electricity to flow arbitrarily between nodes without reflecting physical network constraints [32].

3.3 Dynamic line rating extension to EHUB Nordic

In **Paper III**, the grid representation in EHUB Nordic is further extended to incorporate DLR. This enhancement allows the transmission capacity to vary by line and timestep based on historical meteorologic conditions, including wind speed, ambient temperature, and solar irradiance, rather than being represented by static capacity limits. Weather data, combined with conductor-specific parameters, such as diameter, absorptivity, and electrical resistance, are used to compute the time-varying transmission capacities for each timestep.

The DLR formulation is fundamentally derived from the thermal balance of the conductor [42], which can be expressed as:

$$q^c_{n,m,t} + q^r_{n,m,t} = q^s_{n,m,t} + {I^{max}_{n,m,t}}^2 * R_{n,m,t} \; \forall n, m, t \tag{2}$$

Here, the left-hand side represents the heat losses from convection ($q^c_{n,m,t}$) and radiation ($q^r_{n,m,t}$), while the right-hand side accounts for the heat gains from solar absorption ($q^s_{n,m,t}$) and resistive heating in the conductor. The latter is calculated from the temperature-dependent AC resistance of the conductor ($R_{n,m,t}$) and the electrical current flowing through it ($I^{max}_{n,m,t}$). Table 2 summarizes the input parameters used to calculate the terms in Equation (2).

*Table 2. Summary of input parameters used to calculate the terms in Equation (2). First presented in **Paper III**.*

Term in Eq. 2	Explanation	Input parameters
$q^c_{n,m,t}$	Heat loss from convection. Forced or natural.	• Conductor temperature • Ambient air temperature • Wind speed • Wind direction • Conductor diameter and surface roughness
$q^r_{n,m,t}$	Heat loss from radiation	• Conductor temperature • Ambient air temperature • Conductor emissivity • Conductor diameter
$q^s_{n,m,t}$	Heat gain from insolation	• Conductor absorptivity • Projected area of conductor • Solar influx to conductor
$R_{n,m}$	Heat gain from electrical resistance of conductor.	• Material resistance • Conductor temperature

Solving Equation (2) for the maximum permissible current, commonly referred to as the 'ampacity', yields:

$$I^{max}_{n,m,t} = \sqrt{\frac{q^c_{n,m,t} + q^r_{n,m,t} - q^s_{n,m,t}}{R_{n,m}}} \; \forall n, m, t \tag{3}$$

The resulting ampacity, calculated for each timestep, is subsequently used to determine the maximum thermal capacity of all the lines in the EHUB Nordic model. In addition, the allowable transfer capacity between nodes ($F_{n,m,t}^{max}$) is constrained by the maximum voltage angle difference between nodes from Equation (1). Thus, the minimum value expressed in Equations (4) and (5) is used to set the maximum transmission capacity per timestep in the model:

$$F_{n,m,t}^{max,thermal} = \sqrt{3} * V_{n,m}^{rated} * I_{n,m,t}^{max} * SF \quad \forall n,m,t \tag{4}$$

$$F_{n,m,t}^{max,angle} = B_{n,m} * \sin\left(\Delta\theta_{max}\right) * SF \quad \forall n,m,t \tag{5}$$

The maximum voltage angle difference between nodes in Equation (5), $\Delta\theta_{max}$, is here set to 30° as the standard assumption, to reflect the transient stability requirement. The safety factor (SF) in Equations (4) and (5) accounts for N–1 security as well as additional reactive power loading and is set to 0.7, in line with similar grid modelling literature [26].

4 Selected results

This section is structured into three parts, each corresponding to one of the research questions outlined in Section 1.2. Section 4.1 addresses RQ1 by analyzing how local specificities influence electrification in urban areas, with particular emphasis on the heating sector. Section 4.2 examines the key drivers of optimal spatial localization of VRE generation, addressing RQ2. Section 4.3 addresses RQ3 by assessing how geographic specificities affect the system value of DLR, with particular attention to social acceptance constraints related to wind power and utility-scale solar PV deployment. The results presented include selected findings from **Papers I–III**, as well as additional modeling outputs.

4.1 Impacts of local conditions on cost-efficient electrification in Swedish cities

Paper I investigates how variations in local urban characteristics influence the cost-optimal configurations of the technologies required to meet future energy demands in urban energy systems. The analysis in **Paper I** is conducted using the City model, applied to six Swedish cities, based on measured data. The modeled cities are chosen to represent a wide range of characteristics in terms of levels of industrialization, population size, heating demand, and projected establishment of new industries. To account for uncertainties related to the future electricity import capacities of the cities, two capacity cases are considered: High import, and Low import.

For the district heating sector, the results are illustrated in Figure 3, which depicts the annual heat production by technology within the district heating system for the six modeled cities, for the two cases of electricity import capacity of the city applied in **Paper I**.

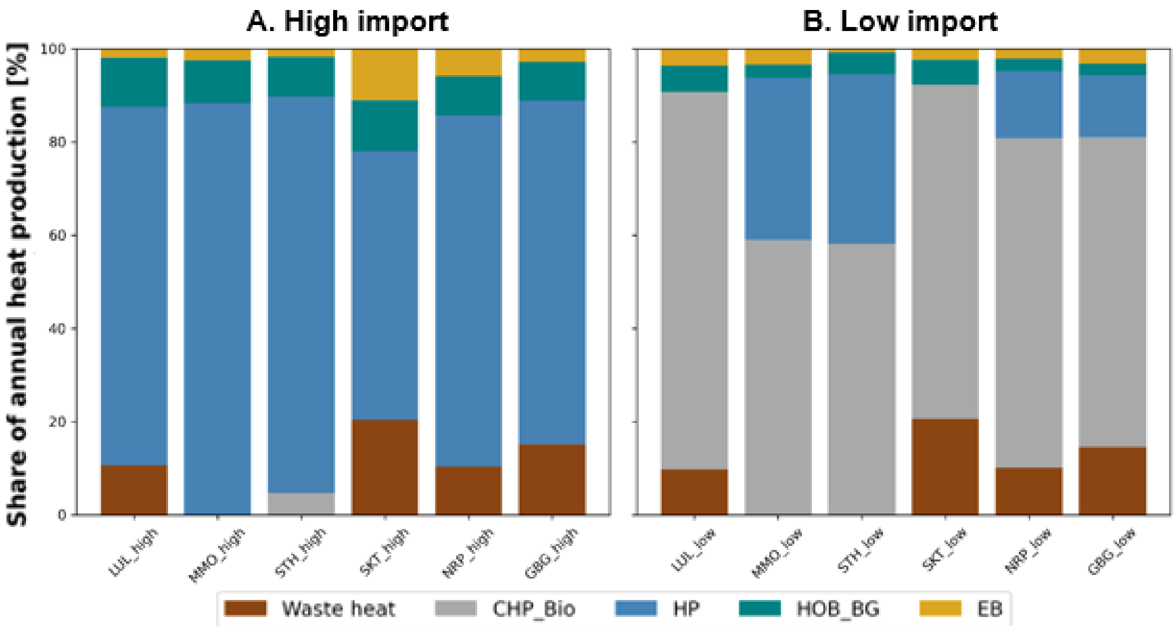

*Figure 3. The resulting annual heat production mix, expressed as each technology's share of the total annual heat generation, for the six modeled cities in **Paper I**, for High and Low import cases. The production sources include CHP_Bio (biomass-fired combined heat and power), HP (heat pumps), HOB_BG (biogas-fueled heat-only boilers), and EB (electric boilers).*

As shown in Figure 3A, a significant reliance on heat pumps in district heating systems is observed across all modeled cities under the High electricity import capacity scenario. In this case, all cities also exhibit a strong dependence upon electricity imports, largely independent of the local characteristics. When the electricity import capacity is more restricted in the Low import scenario, as illustrated in Figure 3B, there is a clear shift from heat pumps towards combustion-based CHP systems. On the electricity supply side, a similar, albeit less-pronounced, shift occurs towards solar PV and biomass-based generation, which become more-significant contributors to local production.

In addition, under such constrained import conditions, the differences between the modeled cities become more pronounced. In particular, as demonstrated Figure 3B, the share of power-to-heat varies considerably across cities in the Low import case in **Paper I**, despite having similar levels of import congestion. Cities with a low electricity-to-heat ratio (MMO and STH), defined as annual electricity demand divided by annual heat demand, exhibit a higher share of heat supplied by electricity when the capacity to import is constrained. This result is closely linked to the installed CHP capacity in the city. A larger CHP capacity reduces pressure on the electricity interconnection to the external grid, thereby indirectly enabling the use of heat pumps in combination with CHP, even under restricted import conditions.

Furthermore, the results described in **Paper I** show that the level of demand flexibility within each city influences the optimal system configuration. The ability to shift electric loads over periods of several months supports the cost-optimal deployment of solar PV and stationary batteries within the city. In a broader sense, these findings indicate that the energy-related characteristics of the cities only become distinguishing factors in the results when the capacity to import electricity is sufficiently constrained. As shown in **Paper I**, for the local characteristics to start having a significant impact on the results, the import capacity has to be limited such that the maximum import capacity is utilized for >5,000 h per year. A figure significantly higher than today's levels for any city in Sweden.

To assess further the results from **Paper I**, a comparison of the heat production mix is made with the outcomes from the EHUB Nordic model introduced in **Paper II**. When applying technology and biomass cost assumptions consistent with those used in the City model in **Paper I**, the resulting aggregated annual heat production mix across the whole Nordic region closely resembles that of the high electricity import case shown in Figure 3A. In the output from the EHUB Nordic model, heat pumps account for more than 85% of the total heat production in district heating systems across the modeled region, complemented by electric- and biogas-fired boilers. This result holds true under assumptions regarding both moderate and high future electricity demands, indicating a strong potential for expanding power-to-heat in district heating systems despite increasing competition from other sectors undergoing electrification.

To understand the competitiveness of large-scale heat pumps in future district heating systems, it is essential to examine their seasonal dispatch patterns. During summertime, when the heat demand is low, heat pumps operate at high output for a limited number of hours, typically coinciding with periods of high solar irradiance and low electricity prices. Excess heat produced during these hours, beyond what is required to meet the immediate demand, is stored in thermal energy storage tanks and subsequently used to satisfy the heat demand during the remaining time of the day. This operational flexibility enables heat pumps to achieve very low, effective "fuel costs" during the warmer periods of the year. During spring and autumn, when heat demand is higher and exhibits pronounced diurnal variation, thermal energy storage instead enables the heat pumps to operate at a consistently high load, thereby achieving a high number of full-load hours.

In winter, when the heat demand peaks, heat pumps typically operate at maximum capacity for most hours, although they may temporarily halt production during periods of high electricity prices. This behavior is illustrated in Figure 4, where the heat dispatch (left y-axis) for one of the modeled cities (Gothenburg) in **Paper I** is plotted against the electricity import prices (right y-axis). As shown, heat pump operation (blue shading in Figure 4) ceases entirely when electricity prices exceed approximately 200 EUR/MWh, with biogas boilers (green shading in Figure 4) compensating for the reduced heat pump output. This substitution is made possible by the high levels of operational flexibility and short start-up times of both technologies. Consequently, the deployment of heat pumps within district heating systems does not exacerbate electricity shortages during hours of high electricity cost.

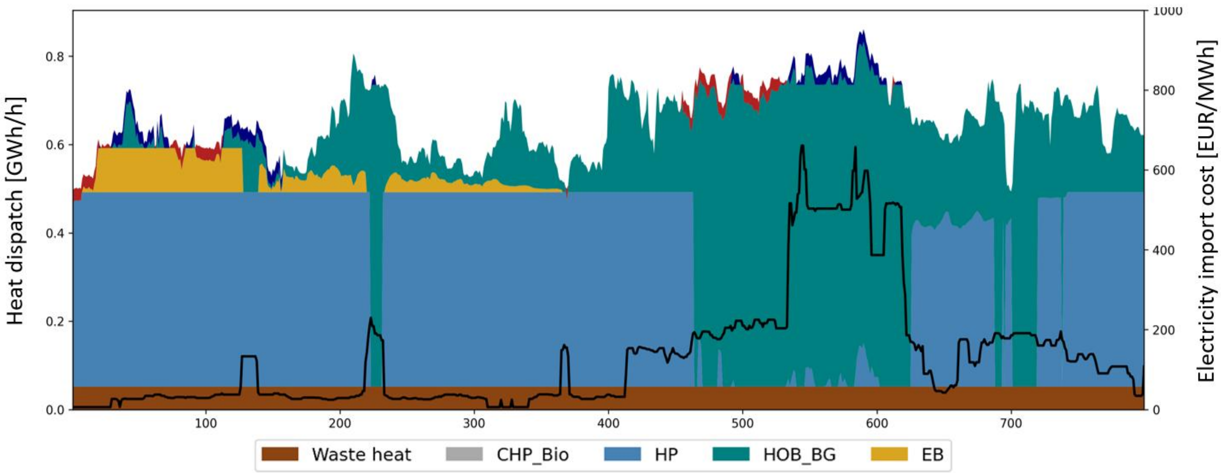

*Figure 4. Heat dispatch for Gothenburg City during January. The dispatch plot includes HP (heat pumps), HOB_BG (biogas-fueled heat-only boilers), and EB (electric boilers). Based on the modeling results from **Paper I.***

A similar operational pattern for heat pumps is observed in the EHUB Nordic model output. Although the total installed electric capacity for power-to-heat (heat-pumps and electric boilers) across the Nordic region amounts to 10 GW, suggesting a potential increase in electric peak net load of 14% if run at maximum capacity, the actual impact is much smaller. Owing to the dynamic interaction with biogas-fired heat-only boilers, electricity use for power-to-heat increases the maximum system net load peak by only about 0.7% or 0.47 GW. Therefore, from a broader energy-system perspective, a higher penetration of power-to-heat in district heating adds flexible demand, enhancing the value of non-dispatchable generation rather than exacerbating peak-load challenges. This flexibility benefit is a key advantage of integrating large-scale heat pumps into district heating networks, in contrast to individual household heat pumps, which are limited to shorter periods of demand-shifting [43].

4.2 Cost-optimal placement of variable renewable energy in the Nordic energy system

In **Paper I**, all the investigated cities show a strong dependence on electricity imports from the surrounding transmission grid, especially in the High import case where 100% of the supplied electricity originates from imports. In the EHUB Nordic model results for Gothenburg, in which wind power deployment is permitted based on land availability across the full corresponding Voronoi-cell, the annual electricity import levels for the node are comparable to those observed in the Low import case of the City model. However, the composition of local electricity generation differs markedly. Under conditions of restricted import capacity, Gothenburg in the City model relies primarily on solar PV, biomass-fired CHP, and gas turbines, whereas local generation in the EHUB Nordic model is dominated by wind power. In the modeling framework of the City model, however, wind power is excluded, so as to reflect the lower levels of social acceptance in urban areas. Consequently, the lack of local electricity production in the High import case in **Paper I** should not be interpreted as evidence of a low system value for local generation, but rather as a modeling artifact resulting from the exclusion of wind power in the City model.

Table 3 illustrates this outcome, alongside the results for the Low import case, using the city of Gothenburg as an example. In addition, In the EHUB Nordic model results for Gothenburg, in which wind power deployment is permitted based on land availability across the full corresponding Voronoi-cell, the annual electricity import levels for the node are comparable to those observed in the Low import case of the City model. However, the composition of local electricity generation differs markedly. Under conditions of restricted import capacity, Gothenburg in the City model relies primarily on solar PV, biomass-fired CHP, and gas turbines, whereas local generation in the EHUB Nordic model is dominated by wind power. In the modeling framework of the City model, however, wind power is excluded, so as to reflect the lower levels of social acceptance in urban areas. Consequently, the lack of local electricity production in the High import case in **Paper I** should not be interpreted as evidence of a low system value for local generation, but rather as a modeling artifact resulting from the exclusion of wind power in the City model.

Table 3. Resulting annual electricity production by technology for Gothenburg, comparing two scenarios from the City model with the corresponding results from the EHUB Nordic model.

	Gothenburg City model: High import case	**Gothenburg City model: Low import case**	**Gothenburg node in EHUB Nordic model**
Import capacity (GW)	1.52	1.08	1.51
Import (GWh)	11073	6507	6176
PV (GWh)	0	2702	808
CHP Biomass (GWh)	0	752	0
Gas turbine biogas (GWh)	0	510	0
Onshore wind (GWh)	0	0	807
Offshore wind (GWh)	0	0	4017
Total	**11073**	**10471**	**11183**

The cost-efficient localization of production sources is further examined in **Paper II**. Based on the work presented therein, Figure 5 illustrates the spatial distributions of onshore wind (Panel A), offshore wind (Panel B), and solar PV (Panel C) in relation to the annual net demand for all the modeled nodes in the EHUB Nordic model. Annual net demand is here defined as the total annual electricity demand minus the annual electricity generation from exogenously specified hydropower and nuclear power. Each marker represents a node in the EHUB Nordic model with a non-zero maximum production potential for the respective technology. Thus, the lowest number of markers is seen in the offshore wind plot (Panel B) as this technology is limited to coastal nodes. Blue markers indicate nodes at which the respective technology is installed. The horizontal line represents the average number of possible full-load hours across all nodes in the model. These two lines divide each plot into four quadrants. The average capacity values shown in each quadrant reflect the average utilization of the permitted onshore wind capacity for the nodes that fall within that quadrant.

Several observations can be drawn from the plots in Figure 5. First, comparing Panel A with the other panels reveals that onshore wind exhibits the highest average installed capacity across all four quadrants. In particular, onshore wind displays substantial deployment at sites with relatively poor wind conditions but high annual net demand (lower-right quadrant of Panel A), indicating a high value for local electricity production in these nodes. The same behavior is not observed for offshore wind in Panel B, where the capacity is concentrated almost exclusively at nodes with above-average annual full-load hours, reflecting the capital-intensive nature of offshore wind, which requires high production volumes to be economically viable. Furthermore, Panel A shows that all nodes with annual full-load hours exceeding 3,300 and annual net demand >1,000 GWh see investments in onshore wind. This indicates that above-average production conditions in combination with a sufficiently high local electricity demand constitute a strong determinant of cost-efficient onshore wind deployment.

Solar PV generation (Panel C) shows the strongest correlation between plant location and annual net demand. Almost no solar PV capacity is installed in nodes that have a negative net demand. The few exceptions occur usually where solar PV is co-located with nuclear power, as these nodes benefit from strong grid infrastructure. These exceptions also highlight the key constraint limiting solar PV deployment: its highly variable production profile, characterized by sharp midday peaks. Such production profile is poorly suited for transmission through the wider grid, making PV heavily dependent upon high local electricity demand to provide a high value in the model. This observation is further reinforced by the findings of **Paper III**, in which solar PV is the VRE technology that benefits most, in terms of increased deployed capacity, from the higher transmission capacities enabled by DLR.

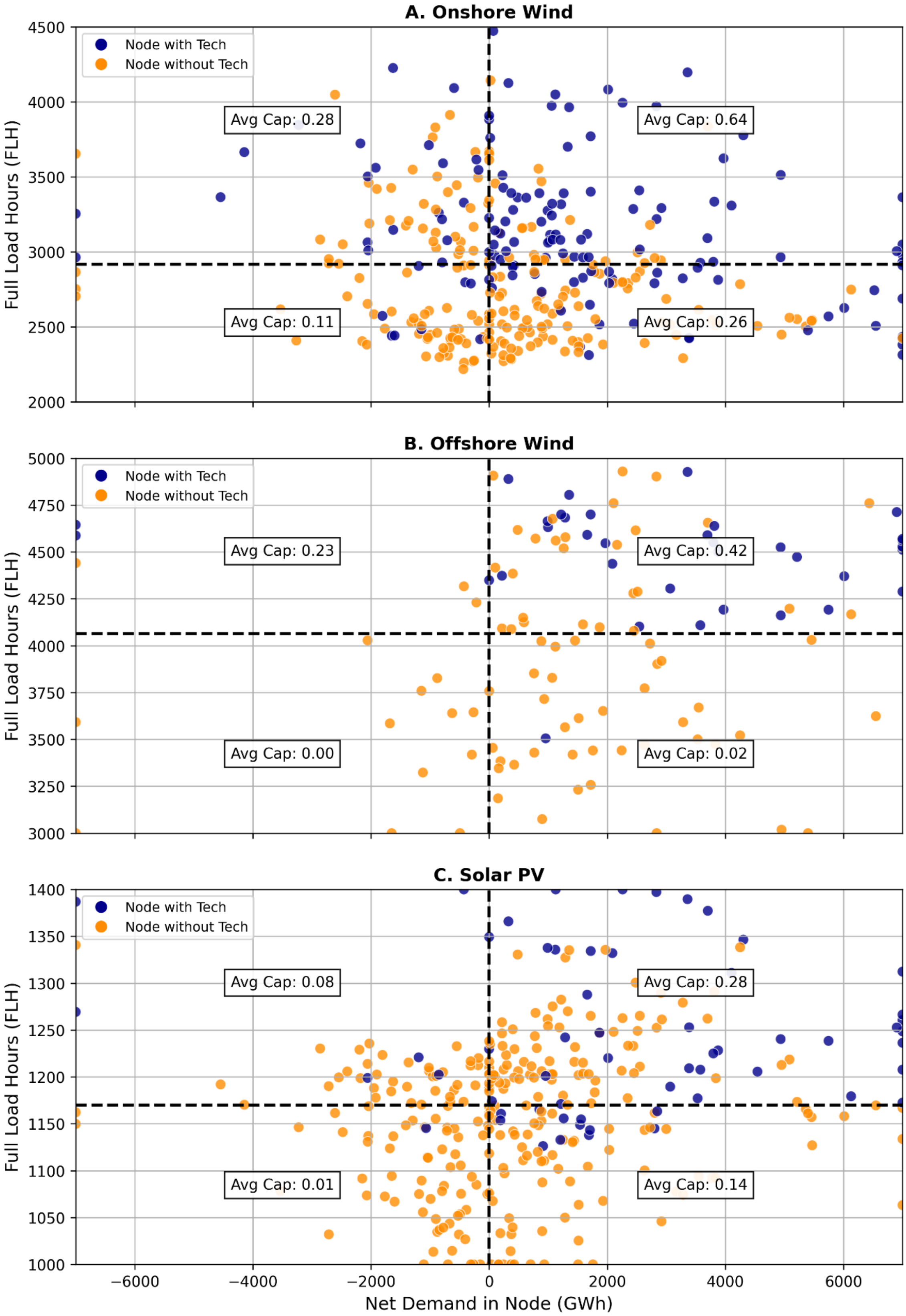

Figure 5. Scatter plots depicting the installation of onshore wind, offshore wind, and solar PV, respectively, in all nodes in the model, plotted against Full-load hours (FLH) (y-axis) and the annual net demand in the node (x-axis). The blue circles indicate that the corresponding technology is installed in that node. The horizontal dotted line represents the average FLH value of all the included nodes, while the vertical line indicates the distinction between positive and negative node annual net demands. The presented average capacity values represent the average utilized capacity for the datapoints located in the respective quadrants. Nodes with zero capacity are excluded from the plot. Data based on ***Paper II****.*

In the high-demand scenario in **Paper II**, upon which the plots in Figure 5 are based, the total electricity demand in the Nordic region increases by approximately 80% relative to Year 2019 levels. Despite this substantial surge in demand, the modeling results indicate a significant potential for meeting a large fraction of the additional demand locally, primarily through extensive deployment of onshore wind, complemented by solar PV and offshore wind. The combination of strong wind resources, high availability of land, and the presence of a flexible hydropower system in the Nordic countries is central to enabling this outcome. Notably, particularly for onshore wind, cost-efficient investments do not necessarily require high-quality production sites; a sufficiently high local demand can justify deployment even at nodes with modest or low full-load hours. However, realizing this potential depends critically on the availability and social acceptance of suitable land in proximity to the demand centers, especially for onshore wind, for which stricter land-use restrictions and public opposition may prohibit development entirely in some areas.

4.3 System value of dynamic line rating under Nordic conditions

In **Paper III,** DLR is introduced as a strategy for increasing transmission capacity by adjusting line thermal limits based on local weather conditions, thereby offering a complement to conventional grid reinforcement. The results indicate that implementing DLR can reduce the total system cost by approximately 4%, with a substantial share of these savings achievable through partial targeted deployment. Specifically, around 39% of the total cost reduction is accrued by equipping only 6% of the transmission lines with DLR.

The analysis in **Paper III** further demonstrates that geographic specificities strongly influence the system-level benefits of DLR. In particular, the presence of substantial hydropower capacity in the modeled region allows DLR to reduce reliance on thermal peaking units through the alleviation of transmission bottlenecks that would otherwise constrain hydropower dispatch, enabling it to penetrate further into the grid. In addition, DLR is shown to affect primarily the spatial allocation of onshore wind rather than its total installed capacity, shifting investments towards sites with higher annual production potentials. DLR also facilitates an expansion of solar PV, the technology that is most constrained by transmission congestion in the Nordic context. This increase is enabled by the region's characteristically low ambient temperatures, which allow DLR to enhance transmission capacity even during periods of high solar irradiance, which would otherwise reduce the line ratings. Finally, **Paper III** highlights the importance of enforcing a maximum voltage angle difference constraint in systems that are characterized by long transmission lines (exceeding 100 km), as omitting this constraint can result in solutions that are infeasible when validated using a non-linear AC power flow analysis.

The findings presented in **Paper III** with regards to the impact of DLR on solar PV and wind power deployment contrast with previous studies that have identified DLR as an important enabler of the integration of additional wind power [44], particularly by allowing offshore wind generation to be transmitted further inland [36]. In the Nordic context, however, high-quality onshore wind resources are generally abundant, even in proximity to major demand centers, thereby limiting the value of transmitting low-cost electricity within the modeled geographic scope. Nevertheless, this conclusion relies on a certain degree of social acceptance for developing onshore wind near demand centers, such as cities, and does not account for constraints such as municipal veto rights or military land use.

In the results obtained from the EHUB Nordic model in **Paper II**, a large share of new onshore wind capacity (71% of the Swedish total) is allocated to the two southern bidding zones: SE3 and SE4. These are regions with anticipated large electricity production deficits compared to demand and with good conditions for onshore wind production. Historically, however, the deployment of onshore wind in these regions has been heavily constrained, primarily due to local opposition [45]. Between Years 2020 and 2024, 82% [45] of all onshore wind power plants that applied for permits in SE3 and SE4 were rejected due to municipal vetoes, a trend that has increased in recent years [46]. In addition, offshore wind deployment in these regions face permitting constraints due to competing interests from the armed forces. Similarly, large-scale solar PV installations are subject to political debate, particularly in southern Sweden and Denmark, where solar development competes with land use for agriculture.

Thus, to assess the implications of the land-use assumptions applied in this work, four different cases are introduced in this thesis. The first is the *Baseline* case, which applies the same land-use constraints for wind and solar power as in **Paper III** and uses static line ratings for transmission capacity. The second case, referred to as *Limiting Wind*, reflects a more-restrictive acceptance of wind power. In this case, no additional wind power capacity is permitted in Swedish bidding zones SE3 and SE4 beyond the levels installed in Year 2024. The third case, *Limiting Wind & PV*, represents an even stricter land-use regime. Here, wind power is constrained as in the *Limiting Wind* scenario, and no additional land-based solar PV (solar parks) is allowed in SE3 or SE4. Roof-mounted PV remains available under the same assumptions as in the *Baseline* case. Finally, a fourth case, *Introducing DLR*, is included to assess how the system value of DLR changes under more-stringent land-use constraints for VRE generation.

The resulting annual electricity production mixes for the entire modeled area, expressed as changes compared to the *Baseline* case, are presented in Figure 6 for the different cases. The corresponding changes in the localization of onshore wind and solar PV capacities are illustrated in Figure 7. To highlight changes between the cases, the maps in Figure 7 depict incremental differences in installed capacity per node as compared to the *Baseline* case, rather than absolute levels. In this representation, green indicates an increase in capacity relative to the *Baseline* case, whereas red denotes a decrease.

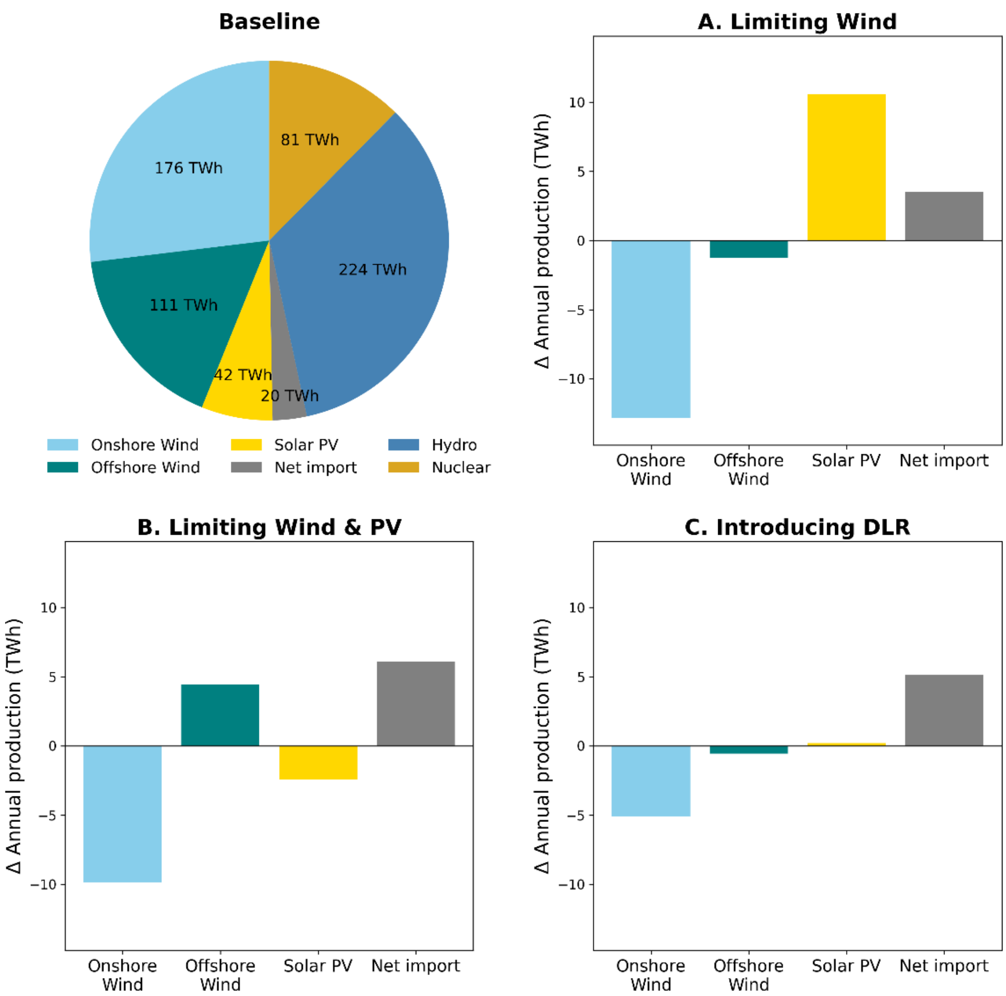

Figure 6. The upper-left panel shows the annual production mix from the Baseline modeling output, by technology type. The other three panels show the changes in annual production compared to the Baseline case, in TWh per technology type, for the modeling cases summarized in

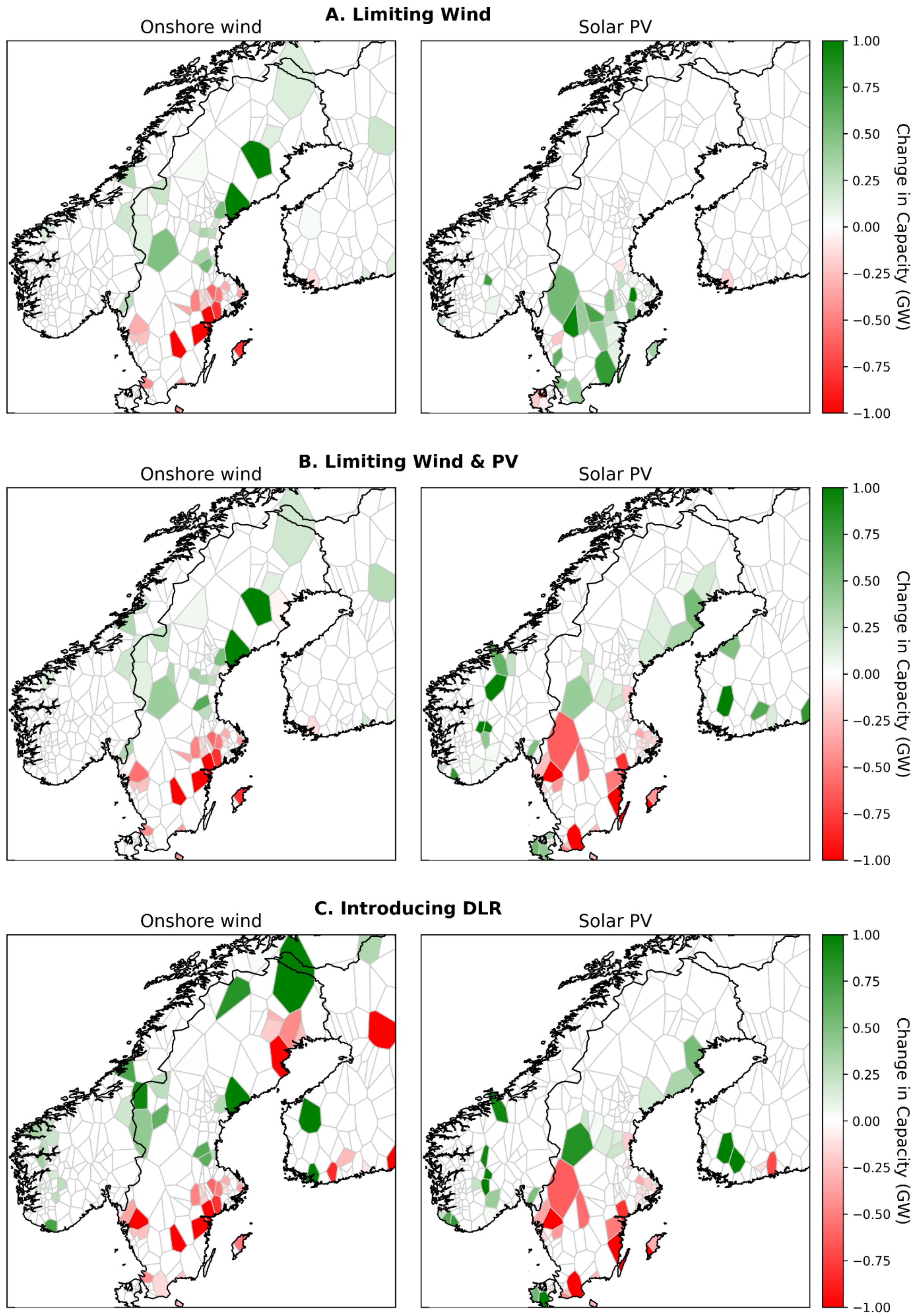

Figure 7. Changes in the installed capacities of onshore wind and solar PV for the three cases, as compared with the Baseline case. In this representation, green indicates an increase in capacity relative to the Baseline case, whereas red denotes a decrease in capacity.

As shown on the left-hand side of Panel A in Figure 7, the introduction of stricter land-use constraints in SE3 and SE4 results in the relocation of onshore wind capacity, primarily towards northern Sweden. However, this shift does not fully compensate in terms of annual production (Panel A in Figure 6) for the reduction in onshore wind deployment in the south of Sweden. Consequently, a substantial increase in utility-scale solar PV capacity is observed across southern Sweden, as seen in the right-hand side of Panel A in Figure 7. This development is accompanied by an increased battery capacity in the region, which helps to manage the greater intraday variability associated with higher PV penetration, leading to a 16% increase in total battery capacity across the Nordic system. In addition, reliance on electricity imports from continental Europe increases, as reflected in Panel A in Figure 6.

When stricter land-use constraints on solar PV are enforced in the *Limiting Wind & PV* case, a pronounced reduction in annual PV generation is observed in Panel B in Figure 6. This is also indicated by the expanded red-shaded areas across southern Sweden in Panel B of Figure 7. In response, offshore wind power partly replaces the lost PV generation. Owing to its smoother production profile, offshore wind is better suited for long-distance transmission of the produced electricity and, therefore, becomes more attractive in the system mix when generation must be located farther from load centers. In addition, dependence on electricity imports increases further in the *Limiting Wind & PV* case, particularly during hours with low electricity import prices associated with high-level wind production in continental Europe. In this case, net electricity imports to the Nordic region reach around 27 TWh annually, in stark contrast to the net export of approximately 41 TWh observed in Year 2023 [47].

With the introduction of DLR, a shift in annual production levels by technology is observed toward a configuration resembling the *Baseline* case. While total wind power production is slightly lower than the *Baseline* case, this is compensated by higher annual electricity imports. However, as illustrated in Panel C of Figure 7, the geographic distribution of generation differs substantially between the cases. This variation is attributed to both improved access to high-quality wind sites enabled by increased grid capacity and the land-use constraints imposed in southern Sweden. As a result, the average distance between generation and demand sites increases by 11% compared to the *Baseline* case.

Furthermore, the reduction in total system cost achieved by introducing DLR, relative to the *Limiting Wind & PV* case in which land-use constraints are more restrictive, amounts to approximately 6%. As this clearly exceeds the 4.3% cost reduction observed with DLR in **Paper III**, it suggests that the system value of DLR reported in **Paper III** would likely be higher under more-stringent land-use assumptions across the modeled region. This finding is consistent with previous studies, such as that of Glaum and Hofmann [36], which have demonstrated that DLR can provide system value by facilitating the transmission of larger shares of wind-based electricity across a larger geographic region. In the broader perspective, the results indicate that DLR not only offers a pathway for alleviating limitations associated with low levels of social acceptance of grid infrastructure expansion, but may also provide substantial system value in those contexts in which social acceptance constraints limit land availability for both solar PV and wind power deployment.

5 Discussion

5.1 Reflections on general results

The results presented in **Papers II** and **III** indicate strong predominance of VRE, particularly onshore wind, in the new electricity generation investments required to meet the expected increase in electricity demand, effectively complementing the Nordic region's substantial existing hydropower and nuclear capacities. The competitiveness of onshore wind is driven by several favorable local conditions: strong meteorological characteristics for wind generation; substantial land availability for development close to demand sites (subject to social acceptance); and a large existing hydropower fleet that provides valuable system flexibility, particularly during periods of low wind power output. However, several potentially important constraints on VRE deployment fall outside the scope of the present analysis. These include material resource availability, grid stability aspects and historically observed deployment rates. Incorporating such factors might impact the quantitative outcomes of the modeling.

The findings presented in this thesis are based on an optimization framework that minimizes the total system cost across the entire modeled energy system. As a result, the outcomes implicitly assume that individual actors behave in ways that collectively advance system-wide efficiency. This assumption may not align with the objectives of real-world actors, who typically prefer to maximize their own profits rather than optimize system-level performance. Moreover, the model does not incorporate all the economic constraints faced by individual entities, such as local grid tariffs, taxes, and labor costs. The work presented here should, therefore, not be interpreted as a prediction of how the future energy system will unfold, but rather as an analytical foundation that can inform policy design aimed at guiding the decisions of individual actors towards the desired system-level outcomes.

In addition, several factors that are not captured in a techno-economic optimization model may hinder a transition toward the system-optimal solutions identified here. The adoption of new technologies, particularly those required for industrial electrification, introduces uncertainties that demand risk-management strategies beyond the scope of a cost-minimization framework. Behavioral and organizational changes among key stakeholders may likewise present significant implementation challenges. Moreover, increasing sector coupling creates new forms of interdependence and vulnerability, which may be perceived as economic risks. For example, the utilization of industrial low-temperature waste heat via heat pumps introduces dependency risks if the associated industrial facilities relocate or cease operation permanently.

This thesis investigates the anticipated electrification of the Nordic energy system by evaluating different technological pathways while accounting for the influence of local geographic characteristics. In doing so, it provides insights into the *how* and *where* of future energy system development. However, it does not address the equally critical question of *when*. If electricity demand increases faster than new production capacity can be deployed, electricity prices may rise to levels that undermine the international competitiveness of electricity-intensive industries. Conversely, if generation capacity expands too rapidly, producers may face economic losses due to prolonged periods of low electricity prices. Although low prices may attract additional electricity-intensive industries seeking to capitalize on favorable conditions, long construction times and investment horizons underline the importance of strategic timing. Therefore, ensuring a stable financial environment, supported by coherent and long-term policy instruments for both producers and consumers, is likely to be a critical factor in facilitating a balanced transition.

5.2 Methodological reflections

The methodological framework applied in this thesis is based on a single representative weather-year, which was selected to limit the computational complexity at high geographic resolution. The year 2019 was chosen as it reflects typical wind conditions and electricity demand levels prior to the COVID-19 pandemic. Relying on a single weather-year implies that investment decisions are optimized under the assumption that the meteorological conditions of the chosen year persist over the technical lifetime of the assets. Consequently, the results do not guarantee system adequacy under alternative weather conditions and do not fully capture inter-annual variability. This limitation is particularly relevant for peaking technologies with low investment costs that operate only during infrequent extreme conditions, such as gas turbines in the electricity sector and biogas-fired boilers in district heating systems. For these technologies, the results presented in this work should, therefore, be interpreted as indicative low estimates rather than as precise values for the required installed capacity.

Another limitation of the applied methodology is its reliance on perfect foresight. This assumption implies that the model has complete knowledge of future demand and weather conditions over the entire modeled period at the timepoint when both investment and dispatch decisions are made. A clear example of this is the dispatch of hydropower reservoirs: already at the first timesteps of January, the model has full information about the electricity demand, water inflows, and wind conditions throughout the remainder of the year. This allows the optimization to determine reservoir drawdown strategies that minimize the total system cost with perfect accuracy, reducing the value of other long-term storage technologies. Such an assumption does not reflect real-world conditions, where system operators must make decisions under conditions of uncertainty and cannot perfectly predict future developments. This modeling assumption also leads to an overestimation of the system value of reservoir hydropower. In particular, the model may underestimate the extent of scarcity events and price volatility during cold or dry periods, as hydropower can be dispatched with perfect timing to meet peak demand. Consequently, similar to the reliance on a single weather-year, the needs for peaking capacity and long-term storage are likely underestimated relative to a modeling framework with limited foresight.

Furthermore, the reliance on perfect foresight likely reduces the system value of firm, low-carbon generation technologies, such as nuclear power. Nuclear power provides weather-independent and hydrologically independent generation that contributes to reducing the net load, thereby providing a hedging strategy against system stress from events such as cold, low-wind winters or extended dry years. When there is reliance on perfect foresight and a single weather-year, this insurance value is not fully captured, as hydropower is assumed to absorb uncertainty that otherwise might justify additional firm capacity. The impact of this assumption could be further evaluated by introducing limited foresight into the modeling framework. Thus, in summary, the methodological assumptions discussed above are likely to affect in particular the estimated capacity requirements of thermal peaking units, although they may also contribute to somewhat undervaluing the role of firm generation technologies such as nuclear power, highlighting the need for further methodological development.

Furthermore, dispatch outcomes from the EHUB Nordic model are evaluated for non-linear AC power flow feasibility using an AC power flow simulation. Although successful convergence under these conditions indicates that a feasible AC power flow exists, it does not guarantee system stability, especially in the event of major disturbances. A more-comprehensive assessment would require explicit testing under N-1 contingency conditions and the application of a transient stability analysis.

5.3 Policy implications

In **Paper II**, the optimal localization of production plants and storage units is analyzed across the 354 modeled nodes in the Nordic region. The results show that the optimal placement of VRE, particularly onshore wind and solar PV, is closely linked to the spatial distribution of future electricity demands. While such a localization yields the highest system value, it does not necessarily correspond to the revenue-maximizing outcome for individual asset owners. **Paper II** demonstrates, for example, that it is cost-optimal from a system perspective to invest in onshore wind power at sites that have clearly below-average annual levels of electricity production, provided that these sites exhibit a high local value for electricity. However, this local value is not fully reflected in the current bidding zone structure, as there is no accounting for internal grid bottlenecks within bidding zones. Since a market design with 354 bidding zones across the Nordic region is not considered a realistic option, complementary policy instruments or market mechanisms are needed to promote a spatial allocation of generation assets that is efficient from a system-wide perspective.

In **Paper I**, the impact of a tax on power-to-heat in district heating systems is examined to assess the robustness of the results. As demonstrated, a reduction of the tax on electricity used for district heating similar to that implemented in Finland in Year 2022 (a 97% reduction) could have a substantial impact on decisions regarding investments in district heating systems. Similarly, as shown in **Paper I**, increasing this tax could result in incineration-based heating remaining the most-cost-efficient solution in future urban energy systems. These findings indicate that the careful design and application of this policy instrument can act as a key driving factor or, alternatively, a potential threshold for the transformation of the district heating sector towards more power-to-heat–based production.

It is, however, important to note that this work does not aim to evaluate the impacts of policy measures on the electrification process. Instead, it focuses on a purely techno-economic analysis of investments and dispatch in the Nordic energy system. From a policy perspective, the objective of this thesis is to provide a decision support tool for policy formulation by identifying system-optimal outcomes that can enable a faster and more cost-efficient electrification process.

6 Conclusions

The Nordic energy system modeled in this work demonstrates substantial potential to meet in a cost-efficient manner the large increase in electricity demand that is anticipated as a consequence of the electrification of the industry, transport, and heating sectors. By developing and applying a highly spatially resolved modeling framework, this thesis shows that capturing local characteristics and geographic specificities is important for ensuring cost-effective system development under these conditions.

Large-scale expansion of onshore wind power is shown to have the potential to supply in a cost-efficient manner the largest share of the additional electricity demand. However, to service the emerging demand centers and avoid exacerbating transmission bottlenecks, the spatial placement of generation becomes important. As a result, cost-optimal investments in onshore wind and solar PV are in this work observed even at locations that have relatively modest capacity factors when local electricity demand is high. Colocalization of electricity generation and demand, therefore, emerges as the primary local determinant of optimal siting for these technologies. However, realizing such optimal siting in practice requires a more-granular valuation of electricity production than is currently provided by existing bidding zone structures. Consequently, additional financial or regulatory incentives will be necessary to align investment decisions with system-optimal spatial outcomes.

Modeling results indicate that electrification of the district heating sector in cities, which have historically been reliant on combustion-based technologies, is cost-efficient from the system-wide perspective under most of the assumptions applied in this work. This finding is robust across variations in local characteristics, including industrial demand, population size, and climatic conditions. However, when opportunities for electricity imports from neighboring regions are stringently constrained, the cost-optimal deployment of power-to-heat technologies in district heating systems is substantially reduced. Under such restrictive import conditions, cities with a high heat-to-electricity demand ratio tend to favor district heating systems that combine large-scale heat pumps with bio-based CHP, in contrast to relying exclusively on combustion-based heating solutions. This outcome can be explained by the larger CHP capacities enabled by higher heat demand, which alleviate pressure on electricity interconnections to the external grid and, thereby, indirectly facilitate the use of heat pumps even under constrained import conditions.

Electrifying the heating sector does not necessarily result in a higher electricity peak net load. During periods of increased electricity demand, it is cost-efficient to substitute heat production from power-to-heat technologies with biogas boilers, thereby increasing the peak net electricity load in the Nordic countries by only 0.7%. Consequently, large-scale heat pumps in district heating systems do not increase the need for additional electric peaking capacity, such as gas turbines, but instead provide a flexible demand resource. However, achieving this flexibility requires substantial installed local capacities of biogas-fired heat-only boilers.

The introduction of DLR into the Nordic synchronous grid is estimated to reduce the total system cost by approximately 4%. The driving forces for this cost reduction can be explained by the local geographic characteristics of the modeled region. The presence of long transmission lines, combined with abundant land areas that offer strong onshore wind resources, reduces the relative value of DLR compared with regions such as Central Europe. Instead, the observed system cost reductions associated with DLR in the Nordic countries primarily arise from the alleviation of local transmission bottlenecks that constrain solar PV implementation and limit hydropower flexibility. The results further indicate that the system value of DLR increases under more-stringent land-use constraints on VRE deployment, suggesting that DLR may serve not only as an alternative to grid expansion when social acceptance is limited, but also as a complementary measure to mitigate constraints on VRE siting.

Synthesizing the findings from **Papers I–III**, four local characteristics emerge as particularly influential in shaping electrification outcomes in the Nordic region: *transmission grid properties*, *weather conditions*, *the spatial distribution of electricity demand*, and *land availability*. Transmission capacity and physical grid constraints affect results across all three papers: they influence heating sector electrification in **Paper I**, constrain the deployment of solar PV in **Paper II**, and shape the system value of grid capacity enhancement through DLR in **Paper III**. Weather conditions affect the spatial allocation of VRE in **Paper II** and, in **Paper III**, are shown to enable DLR to increase transmission capacity under Nordic conditions, thereby supporting higher solar PV integration. Land availability and the location of demand centers are identified as key drivers of cost-optimal renewable siting in **Paper II**, while more restrictive land-use assumptions are shown to significantly increase the system value of DLR. Collectively, these results indicate that explicitly accounting for these four factors is essential when analyzing future Nordic energy system development.

In addition, this work underscores the importance of incorporating detailed geographical resolution in energy system modeling. As demonstrated here, capturing local spatial heterogeneity can affect both the cost-optimal capacity mix (e.g., solar PV and thermal peaking units) and operational dispatch patterns (e.g., hydropower utilization). Moreover, a detailed representation of the transmission grid is a prerequisite for evaluating the system value of DLR, since this approach depends on modeling individual transmission lines and their properties. At the same time, higher geographical resolution increases computational requirements and may necessitate coarser representations of other dimensions, such as temporal resolution or the number of weather years included. Ultimately, the appropriate level of geographical detail should be determined by the specific research questions the modeling exercise aims to address.

7 Future work

Much of the planned future work aims to address the limitations outlined in the *Discussion*. For example, a key focus will be on evaluating with greater accuracy the feasibility levels of the modeling constraints related to hydropower and its dispatch, which have been shown to influence significantly the outcomes, particularly regarding the operation of peaking thermal units, such as gas turbines. This will involve applying more-detailed models of hydropower production in different rivers that incorporate more-realistic hydrologic constraints, environmental permit requirements, and turbine efficiency curves. The objective is to assess whether the operational patterns generated by EHUB Nordic can be reproduced within a more-detailed hydropower modeling framework. This work is planned in collaboration with KTH in Stockholm, drawing on hydropower modeling tools developed there.

Future work is also planned to address the limitation of relying on a single weather-year. By incorporating multiple years, including those characterized by extreme weather events, the robustness of the modeling results presented here can be increased. As with hydropower implementation, this enhancement is expected to have the greatest impact on technologies that operate for only a limited number of hours per year and that are primarily deployed to manage rare extreme events, e.g., gas turbines. With a more-comprehensive understanding of how different weather-years influence system outcomes, it will be possible to investigate in greater depth the potential roles and geographic placement of gas turbines in the Nordics.

As also mentioned in the *Discussion*, the model results are currently tested for feasibility using an AC power flow model of the same grid, which does not consider contingency events and captures only steady-state conditions. Future development of the EHUB model will entail assessments of both N-1 feasibility and transient stability, thereby expanding the methodological scope. The aim is to establish an iterative framework in which generator dispatch and transmission line capacity limits, derived from these additional feasibility assessments, are updated and fed back into the EHUB Nordic optimization model.

Finally, a future aim is to address two major points of debate in the current Swedish energy policy landscape. The first point concerns the impacts of more-restrictive assumptions regarding land availability for onshore wind power development. This topic is partly explored in this thesis, although a more-thorough analysis is warranted to identify areas across the modeled region where the system value of wind power is particularly high. The second point concerns the formulation of new electricity bidding zones in Sweden, an issue that is of considerable public interest. The spatial resolution of the EHUB Nordic model provides an opportunity to examine grid bottlenecks that give rise to substantial differences in marginal electricity costs, thereby offering insights into alternative configurations of bidding zone boundaries.

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