THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

From Sweden to the world:

Analysis of future low-carbon electricity systems

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Abstract

The increasing urgency of addressing climate change, along with the sustained cost declines in wind and solar power, has led to a rapid expansion in their deployment to decarbonize the electricity sector. In cost-optimal scenarios for future low-carbon electricity systems, wind and solar often serve as the cornerstone of electricity supply. Although many studies have investigated a future low-carbon electricity system based on wind and solar, there are still several important aspects that are not well understood for such a future system, e.g., uncertainty in future electricity demand patterns, potential for trade in renewable energy, the spatial scope for resource sharing and the role of nuclear power. This thesis investigates these aspects and their potential impacts on developing a low-carbon electricity system.

This thesis reveals that varied electricity demand patterns affect only slightly the electricity system cost for Europe, except for the case of summer peak, where the system cost may increase by up to 8%. The change in demand pattern is generally more consequential to the electricity supply mix than the system cost. Notably, the increased electric cooling demand may change the demand pattern such that the hourly electricity demand is better correlated with the output of solar PV. Through analyzing seven different regions under various CO_2 emission targets, this thesis shows that solar PV is the most cost-optimal generation technology for meeting the cooling demand. In addition, to have a more realistic assessment of renewable energy potential, this thesis introduces a new metric "Renewable levelized cost of electricity available for export", which incorporates heterogeneous discount rates, electricity demand, and land-use requirements. By applying this metric to most of the countries in the world, this thesis shows that countries with significant potential for renewable energy export include the US, China, and Saudi Arabia. Furthermore, this thesis shows that the benefit of an intercontinental super grid, as suggested by the One Sun One World One Grid initiative, is rather limited. Allowing for long-distance intercontinental electricity trade reduces the electricity system cost by 0-5% compared to the case where the continents are isolated from each other. This thesis also shows that integrating different continents always reduces the integration of solar PV, which indicates that an intercontinental super grid is not a cost-effective variation management strategy for solar power. Finally, this thesis shows that including nuclear power in the electricity system reduces the nodal net average system cost by 4% for Sweden. This implies that the economic rationale for Sweden as a country to invest in nuclear power is limited if there is a transition towards a low-carbon electricity system in Europe.

This thesis provides practical information about demand profile treatment for modeling practice, introduces a useful metric for renewable energy trade potential assessment, and generates valuable insights about deploying solar PV to power cooling, and investment in super grid and nuclear power.

Keywords: low-carbon electricity system, energy system modeling, demand pattern, electric cooling, renewable energy potential, super grid, nuclear power, net system cost

Appended publications

This thesis consists of an extended summary of the following appended papers, which are referred to in the text according to their Roman numerals:

I. Kan, X., Reichenberg, L., & Hedenus, F. (2021). The impacts of the electricity demand pattern on electricity system cost and the electricity supply mix: A comprehensive modeling analysis for Europe. *Energy*, 235, 121329.

II. Kan, X., Hedenus, F., Reichenberg, L., & Hohmeyer, O. (2022). Into a cooler future with electricity generated from solar photovoltaic. *iScience*, 25(5), 104208.

III. Kan, X., Reichenberg, L., Hedenus, F., & Daniels, D. (2022). Global renewable potential – including socio-economic factors to explore the potential for international trade. (*manuscript*)

IV. Kan, X., Hedenus, F., & Reichenberg, L. (2022). Six regions one sun one grid: Quantifying the benefits of the global super grid. (*manuscript*)

V. Kan, X., Hedenus, F., & Reichenberg, L. (2020). The cost of a future low-carbon electricity system without nuclear power–the case of Sweden. *Energy*, *195*, 117015.

Paper I: LR conceived the idea with support from FH. XK developed the model and produced the results. All the authors analyzed the results, wrote and edited the paper.

Paper II: XK conceived the idea with support from FH, LR and OH. XK developed the model and produced the results. XK, FH and LR analyzed the results and wrote the paper. All the authors edited the paper.

Paper III: LR conceived the idea with contribution from FH and DD. XK developed the model and produced the results. All the authors analyzed the results. XK, LR and DD wrote the paper. All the authors edited the paper.

Paper IV: All the authors developed the idea. XK developed the model, produced the results and wrote the paper. All the authors analyzed the results and edited the paper.

Paper V: FH and LR conceived the idea. XK developed the model and produced the results. All the authors analyzed the results, wrote and edited the paper.

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To all my friends, thank you for the enjoyable moments we have shared throughout the years and for accepting me into your lives

Finally, thanks so much to my family for always being supportive and loving. You are always there for me. I am so grateful to have you all in my life.

Xiaoming Kan

Gothenburg, February 2023

Contents

Introduction

The electricity sector is currently a major contributor to global CO_2 emissions [1]. Due to the concern about climate change, the decreasing costs of wind and solar technology, and increasing electricity demand, there has been a rapid growth in the deployment of wind and solar energy to decarbonize the electricity sector. Many studies have shown that an electricity system with a high penetration level of variable renewable energy (VRE), such as wind and solar is technically feasible [2-7], and the electricity cost is comparable to the cost of the current system [3, 8-11]. However, there are still several important aspects that are not well understood for such a future system, e.g., uncertainty in future electricity demand patterns, potential for trade in renewable energy, the spatial scope for resource sharing, and the role of nuclear power. Understanding these four aspects and their impacts on a VRE-centered low-carbon electricity system may be crucial to its optimal design. The following reasons elucidate why delving into these aspects is highly compelling.

To begin with, satisfying the electricity demand is the core of the design of any electricity system. The future electricity demand is uncertain due to economic growth, climate change, e-mobility, electric heating, and cooling. These driving factors may strongly influence the volume of electricity demand and the intertemporal demand pattern [35-44]. Many studies investigating future low-carbon electricity systems used historical electricity demand profiles or linearly scaled them up to account for the potential demand growth [2-4, 12-24], but the change in future demand patterns is generally neglected. The demand pattern refers to the way how electricity is consumed over time. The change in demand pattern might affect the optimal investment decisions, which is especially critical in developing a low-carbon electricity system, as VRE sources such as wind and solar power, are intermittent, and their availability may not always align with the demand for electricity [25].

Secondly, quantifying the potential of VRE resources is the foundation for designing an electricity system based on such resources. Plenty of studies investigated the technical potential of wind and solar at the global level [26-37], but only a few analyzed the economic potential, e.g., estimating the levelized cost of electricity (LCOE) for wind and solar [26-28, 35-37]. The economics of a project characterized by high initial investment costs, like wind or solar, is especially sensitive to the discount rate, which varies significantly between countries. The regional economic potential of VRE resources affects the potential for international electricity trade. Yet, studies assessing international electricity trade often assume the discount rate to be homogeneous across the world [38]. Such a simplification may overestimate (or underestimate) the contribution of VRE in certain countries. In addition to the regional discount rate, the potential for trade in VRE can be significantly influenced by two other critical factors: regional electricity demand and land use

constraints. The availability of land affects the total supply potential of VRE, while regional electricity demand represents the amount of electricity that needs to be prioritized domestically.

Thirdly, the spatial scope is essential for designing a VRE system as it defines the system boundary and determines the geographical area over which VRE and dispatchable resources can be shared. Many studies have shown that transmission expansion is a cost-effective strategy for the design of a large national or continental electricity system based on VRE [2, 22, 39, 40]. Typically, connecting different countries via transmission grids at a continental level can decrease the overall system cost by 10-30% compared to the cost when countries are isolated [2, 39, 40]. Similar reasoning has led to concepts such as the One Sun One World One Grid (OSOWOG) initiative, which proposes expanding the spatial scope to a global level by establishing intercontinental super grids for sharing clean energy worldwide, regardless of time. In particular, cross-time zone trading has the potential to contribute to smoothing the day-night variation of solar power output.

Finally, there is no unanimous agreement on the role of nuclear power in the future low-carbon electricity system. Some studies suggest that without firm low-carbon resources such as nuclear power, electricity costs may soar quickly as CO_2 limits approach zero [7, 41, 42]. However, many other studies have shown that the cost of a VRE-based system, combined with transmission and storage, is comparable to the current system's cost [3, 8-11]. In Sweden, nuclear power contributed 31% of the country's total electricity supply in 2021 [43]. As the nuclear fleet ages, decommissioning is planned in the coming decades. The government elected in 2022 planned to reinvestment in nuclear power. Yet, there are ongoing debates as to whether new nuclear power plants should be built.

This thesis aims to investigate the four aspects mentioned above and their potential impacts on developing a low-carbon electricity system. The first part of this thesis discusses the changes in future electricity demand patterns and their consequences on cost-optimal system design. In the second part, the regional potential for VRE trade is evaluated while considering regional discount rates, demand, and land use constraints. The third part of this thesis evaluates the benefits of establishing an intercontinental super grid. The final part of the thesis quantifies the role of nuclear power in a low-carbon electricity system.

Aims

This thesis consists of five papers, and the specific aims are to:

1. Evaluate the effects on the system cost and the electricity supply mix of applying different demand patterns in energy system models (**Paper I**);
2. Evaluate the impact of electric cooling on the cost-optimal investment in solar PV (**Paper II**);

3. Assess the regional VRE potential while taking into account regional social-economic factors such as discount rate, electricity demand, and land use constraint, and identify potential importers and exporters (**Paper III**);
4. Evaluate the impact of an inter-continental super grid as suggested by the OSOWOG initiative on the cost and configuration of the future renewable energy system (**Paper IV**);
5. Investigate the cost of a future low-carbon electricity system without nuclear power for Sweden under conditions with different levels of interconnecting transmission grids within Sweden and between Sweden and neighboring countries (**Paper V**).

Contributions

Paper I evaluates the impacts of different electricity demand patterns on the electricity system cost and electricity supply mix. The conditions under which the choice of demand pattern is influential are identified. This provides valuable information to energy system modelers on whether or not misleading results will be produced if they continue to employ historical electricity demand profiles as inputs to the model.

Paper II reveals how the synergy between the time series of the cooling demand and the solar PV output affects the cost-effectiveness of solar PV in powering electric cooling. The results regarding the dominant role of solar PV in power cooling indicate the cost-effectiveness for tropical countries to invest in solar PV to meet the fast-growing cooling demand.

Paper III introduces a novel metric, Renewable Levelized Cost of Electricity available for export ($RLCOE_{Ex}$), to assess renewable resource potential and trade potential by incorporating electricity demand and land-use requirements. This paper serves as the groundwork providing a basis for analyzing self-sufficiency and trade patterns for renewable electricity and electricity-derived fuels.

Paper IV evaluates the cost benefit of a global super grid as suggested by the OSOWOG initiative. With a geographic area spanning eighteen time zones, this study assesses explicitly the effect of a global super grid on the spatial smoothing of the diurnal variation of solar PV.

Paper V identifies the generation and variation management technologies that are cost-effective to invest in for the future low-carbon Swedish electricity system. It introduces a new method to quantify the nodal net average system cost (NNASC) for a country or region in an interconnected electricity system. This concept incorporates the system-wide capital and operational costs of generation and transmission, profit of trade (revenue from exporting electricity minus the cost of importing electricity), and congestion rent. Compared with studies [44-46] investigating a country in isolation, assuming no cross-border electricity trade or following historical electricity trade patterns, the NNASC approach can reflect the impact of electricity trade on the system cost for a specific country or region in an interconnected electricity system. Through investigating the cost

difference for Sweden with nuclear power relative to a system without nuclear power, the economic benefits of including nuclear power for the future low-carbon Swedish electricity system are analyzed.

Background

This chapter provides a comprehensive overview of the low-carbon electricity system. It covers a range of topics, including low-carbon generation technologies, variation management strategies, the electricity demand pattern, economic performance metrics, and the cost of capital and discount rate. This chapter discusses the advantages and disadvantages of various low-carbon technologies, and introduces the metrics used to evaluate the economic performance of energy technologies. Additionally, it explains the driving factors of the cost of capital and discount rate.

Transition towards a low-carbon electricity system

In 2022, electricity and heat production accounted for 42% of global CO_2 emissions, being the largest CO_2 emitter [47]. The demand for electricity is expected to grow with increases in GDP and population, and with increased integration with other sectors such as transportation and heating. If the increased electricity demand is met by generation using conventional fossil energy, there will be a substantial increase in CO_2 emissions. Thus, decarbonizing the electricity sector has a pivotal role in achieving the CO_2 emissions reduction target. Currently, several mature low-carbon electricity generation technologies exist, e.g., nuclear power and wind and solar power. In addition, decarbonizing the electricity sector is generally regarded as being less expensive compared with other sectors, such as transport and energy-intensive heavy industries [48]. According to the IPCC report, to limit the rise in average global temperatures this century to 2°C above pre-industrial levels, the electricity sector needs to be deeply decarbonized towards the second half of the 21st Century [1]. This implies significant investments in low-carbon generation technologies.

For Europe, the European Commission has presented its strategic long-term vision for a climate-neutral economy by 2050 [49]. To achieve this goal, more and more wind and solar power are invested in Europe for electricity supply. Apart from the fast deployment of wind and solar power, three new nuclear power plants are being constructed in Europe. Other low-carbon electricity generation technologies include hydropower, carbon capture and storage (CCS), biomass and biogas. In the following section, these technologies are briefly introduced.

Low-carbon electricity generation technologies

Wind and solar power exhibit a large global technical potential, and the associated costs have been decreasing over the past decades [50], see Fig. 1. The cost reduction is estimated to continue in the coming decade due to economies of scale and learning by doing [50, 51]. According to the International Renewable Energy Agency (IRENA), more than half of the commissioned projects for onshore wind and solar PV in year 2020 will produce cheaper electricity (lower expected LCOE) than new fossil fuel-fired power plants without subsidies [51]. Wind and solar power

accounted for 10% of global electricity generation in year 2021, while the corresponding share in year 2013 was only 3.4% [52]. Given the resource availability, technological maturity, and economic competitiveness, wind and solar are likely to be widely deployed globally. However, wind and solar power has limitations. The power outputs of wind and solar change throughout the course of a day, season and year, depending on the weather conditions. Solar power, in particular, has a natural diurnal variation, as there is no solar radiation at night. The output of wind power also has a diurnal variation, with relatively more wind energy produced at night than during the day in many locations [53]. However, the diurnal variation of wind power is less pronounced than that of solar power. In addition, both wind and solar power outputs vary over large geographic areas, albeit the variation is usually larger for wind due to different wind conditions resulting from geographic diversities [53].

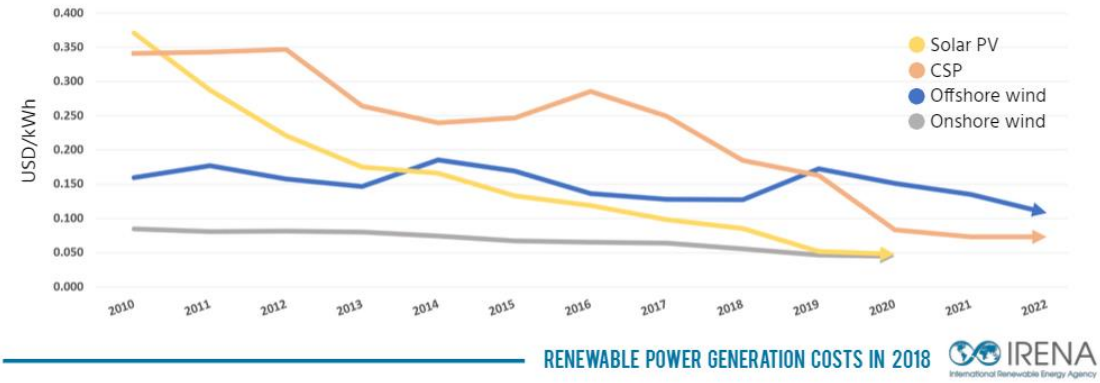

Fig. 1. The development of LCOE for renewable generation technologies (IRENA, 2019).

The future of nuclear power in Europe is uncertain. Germany, Belgium, and Switzerland have decided to phase out nuclear power, while France, the UK and Slovakia are building new nuclear power plants. Apart from the problem of social acceptance linked to perceptions of radiation risks and nuclear waste, the current investment cost for the third-generation nuclear power is very high. The investment cost of the two most recent nuclear power plants (Olkiluoto 3 and Flamanville 3) in Europe is estimated to be as high as 10000 $/kW [54]. This cost could probably be decreased through international standardization and the massive construction of new nuclear power plants. Similar to the case of Europe, the investment cost of nuclear power plant remains high in USA [54]. The situation is more optimistic for nuclear power plants in Russia and in Asian countries, where the investment costs for on-going projects are estimated at around 4000 $/kW [54]. The cost escalation for nuclear power plant in Europe and the USA is mainly driven by the project delay and regulations regarding large-scale construction projects set by strict nuclear standards [54, 55]. As for the operation of nuclear power, it usually runs as the base load. To integrate more effectively nuclear power with VRE, flexible operation of nuclear power has been proposed to

provide flexibility to the future low-carbon electricity system [56, 57]. However, this will reduce the utilization time for nuclear power, leading to a higher LCOE for nuclear power.

Reservoir hydropower (hydro reservoir) and run-of-river hydropower (hydro RoR) are conventional renewable energy technologies that are used worldwide. Hydro reservoir is considered to be a flexible power source, as it is quick to react and is capable of providing full capacity within a timeframe of seconds to several minutes [58, 59]. For hydro reservoir, water can be stored for days, months or even years, depending on the reservoir size, and released whenever electricity is needed [60]. The resource availability for hydro power varies from one geographic region to another. In Europe, due to environmental regulations, the capacities of hydro reservoir and hydro RoR are not likely to increase in the future. One important environmental regulation related to hydro reservoir is the minimum environmental flow [61, 62], which mandates that a certain proportion of the mean annual inflow be released to satisfy the downstream ecosystem and human needs for water.

CCS is a process that captures carbon dioxide emissions from power plants, industrial facilities, or other sources and then stores them in underground geological formations [63-65]. CCS is an emerging technology and as such, there are currently not enough large-scale projects to achieve economies of scale and reduce costs. Currently CCS is still an expansive technology. In addition, there is the perceived risk of carbon dioxide leakage from underground storage sites, which could have negative environmental consequences [64].

As for biomass, it might be used as the source material for other sectors, such as transport and industry. Thus, the price for biomass might remain high due to scarcity of supply. In addition, large production of biomass require a lot of land, which may cause external problems such as the security of food supply and deforestation [66]. Biogas can be produced from manure, agricultural residues and waste. However, due to the scarcity of the biomass primary resource and the demand from the other sectors, the supply of biogas is limited to a small fraction of the overall electricity demand. In addition, there are other low-carbon energy technologies such as geothermal, wave and nuclear fusion that can potentially contribute to the decarbonization of the electricity system. However, these technologies are either location-restricted or far from mature [67].

Variation management strategies

Although the output from wind and solar power fluctuates over time depending on the prevailing weather conditions, there are several ways to provide the flexibility needed to handle the variable generation associated with wind and solar on different time-scales of hours, days and seasons [2-4, 53]. These solutions, which are termed *variation management strategies* (VMSs), need to be able to: shift electricity generation temporally (storage); move electricity generation spatially (trade through transmission grids); shift or curtail electricity demand to adapt to the variable

generation of VRE (demand-side management; DSM); and curtail generated electricity when it is not needed. The main VMSs considered in this thesis are shown in Fig. 2.

First, energy storage can shift the production of VRE over time [68]. Energy storage can save wind- and solar-generated electricity from periods when there is overproduction to periods when the power output of VRE is lower than the demand [68-70]. For this purpose, there are several mature storage technologies, such as different battery technologies, pumped hydropower and thermal energy storage. In addition, the surplus electricity can be applied to produce hydrogen and other synthetic electro-fuel as medium- and long-term storage.

Second, the variation of VRE can be smoothed through the exploitation of a diversity of geographic locations when selecting the VRE generation sites and connecting these sites with transmission grids [71]. The transmission grids enable the transfer of electricity from regions where VRE generators are currently producing electricity to areas where the demand is currently not satisfied [2, 22, 39, 40].

Third, DSM technologies can shift or shed electricity demand so as to fit the fluctuating generation profile of VRE [72]. The potential of DSM can be further increased when there is large-scale sector coupling, as this provides new flexible demand, such as electric vehicle charging, electric heating and power to gas in the integrated energy system [72-74].

Last but not least, the excessive production of VRE can be curtailed when the level of electricity generation is higher than the demand for electricity.

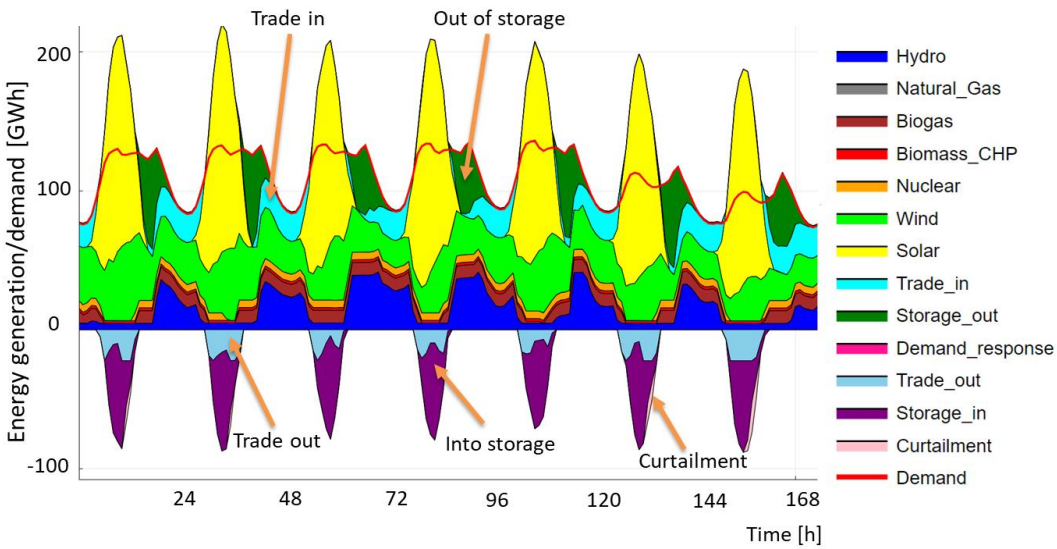

Fig. 2. Variation management strategies used in the electricity system. The figure presented is a conceptual illustration depicting storage, trade, and curtailment. Electricity is stored and traded out during the daytime when the level of generation exceeds the demand. When the output of solar power ramps down sharply in the late afternoon, electricity is released from storage. During the night, there is both electricity release from storage and electricity trade-in.

Electricity demand pattern

The electricity demand pattern is important because it represents the manner in which electricity is consumed over a period of time. Several significant factors can impact electricity demand, including economic growth, climate change, sector coupling (such as e-mobility and electric heating), and electric cooling. Specifically, the economic growth (increase in GDP), can increase the volume of electricity demand, while the GDP level or wealth level can affect the affordability of electric cooling, electric vehicles, etc., which influences the electricity demand pattern. Climate change and sector coupling may affect the overall electricity consumption behaviors, thus, influencing both the volume of the electricity demand and electricity demand pattern. For instance, if there is a massive diffusion of electric vehicles (EVs), the daily peak demand may change significantly depending on the charging strategies used [12]. Fig. 3 shows how different charging strategies for EVs could affect the potential demand patterns for Germany and the UK in year 2050 [12]. Direct charging after work may lead to a very high evening peak, while the smart charging strategy may alter substantially the diurnal demand pattern through shifting the peak demand towards midday hours when there is a high output from solar PV.

As for the seasonal demand pattern, the widespread adoption of electric heating may drive up the winter peak demand, while the large-scale use of electric cooling may result in a higher peak demand in summer. This implies different seasonal demand patterns. Fig. 4 shows the historical and the simulated future seasonal electricity demand patterns for the UK [16]. The demand in summer remains almost constant, while the winter demand increases over time, creating a more pronounced seasonal variation in the demand profile. The increased winter demand is mainly driven by the estimated substantial increase in residential heat pumps. Similar to the case of electric heating, Kannan [21] estimated that the increased use of air conditioners (ACs) may increase the summer peak in Switzerland by 2%–23% by 2050.

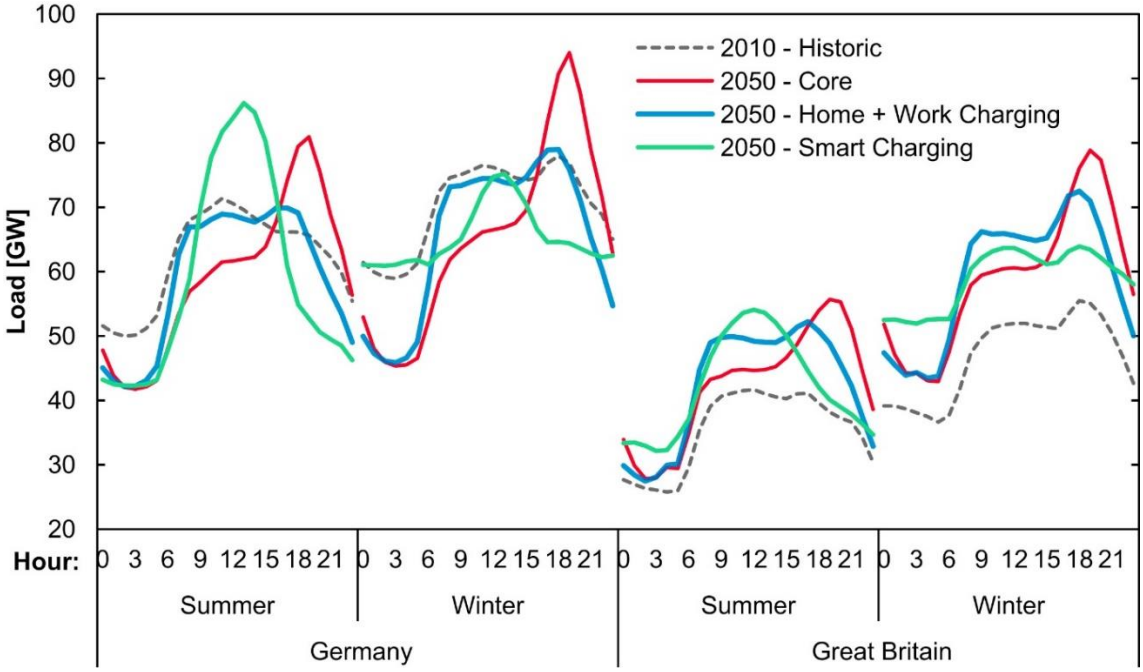

Fig. 3. Potential electricity demand profiles on weekdays under different charging strategies for electric vehicles in year 2050 for Germany and the UK (Figure from Boßmann and Staffell, 2015).

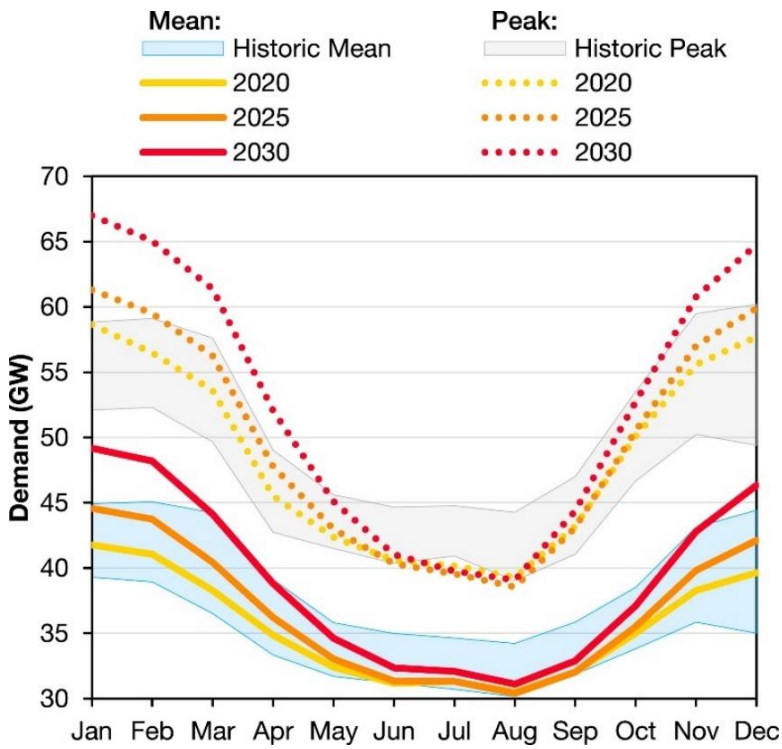

Fig. 4. The seasonal variations in the historic and simulated future demands. The shaded areas indicate the historic range from 2005 to 2015, while the lines show the simulation results for 2020, 2025, and 2030. The dotted lines indicate the peak demand within each month, and the solid lines represent the mean value (Figure from Staffell and Pfenninger, 2015).

Metrics to measure technology cost-competitiveness

This thesis mainly explores the investment for future low-carbon electricity systems with energy system optimization models. One key output is the optimal electricity supply mix which illustrates the competitiveness of different power generation technologies. Conventionally, levelized cost of electricity (LCOE) is commonly used as a simple metric to evaluate technology costs and compare the cost-competitiveness between different energy technologies [75, 76]. LCOE expresses the overall cost of generating electricity from a specific source over its lifetime. It takes into account all project expenses such as capital, operation and maintenance, and fuel costs, and is calculated by dividing the total cost of the project by the total energy output, discounted to present value.

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{T} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}}, \tag{1}$$

where I_t is investment costs in year t, M_t is operation and maintenance costs in year t, F_t is fuel costs in year t, r is discount rate and T is lifetime of the project.

LCOE is widely used to evaluate the economic feasibility of power generation projects. However, LCOE alone is not enough to assess the comprehensive economic performance of energy technologies. First, LCOE do not account for a technology's economic return, including the return on energy, capacity, and ancillary services provided in different markets [77]. Second, it overlooks the variability of VRE production, which requires additional measures like transmission and storage to manage fluctuations [77, 78]. Apart from LCOE, there are several other metrics to evaluate the economic performance of energy technologies, some of which were introduced to remedy the limitations of LCOE.

Levelized value of Electricity (LVOE) is a simple metric to evaluate the economic return of an energy project [77, 79]. Here the value refers to the revenue of an energy project. Unlike LCOE, LVOE focuses solely on the economic return without taking into account the cost. The calculation of LVOE involves dividing the total lifetime economic return of a project by the total electricity produced, discounted to present value. By examining historical electricity prices and anticipated electricity production, the economic return of a new project can be estimated. To bridge the gap between cost and economic return, the Net Value of Electricity (NVOE) is introduced. [77, 80]. It is derived by subtracting LCOE from LVOE. This metric can be used to analyze the profitability of an energy project. Another metric, the Net Value of Capacity (NVOC) is calculated by dividing the difference between the annualized economic return and cost of a project by its installed capacity [77, 81]. This metric can be used to assess the profitability per unit of installed capacity [77, 81].

The LCOE for a technology is typically calculated by considering both investment and operational costs and anticipated electricity production. For VRE technologies, these costs tend to be relatively fixed. When determining the economic return for a marginal increase in generation capacity, historical electricity prices may be used as a basis for the calculation. But if there is a significant increase in generation capacity, historical electricity prices may no longer be a reliable indicator of the market's economic return. This is because the newly added capacity will affect the electricity system and, consequently, the electricity price. In this case, an energy system model is required to capture the interactions between the newly added capacity and the existing system and estimate the electricity price accordingly. With the increase in generation capacity from VRE, additional measures (e.g., storage) are needed to manage the fluctuations of VRE production, which will result in additional system integration expenses for VRE technologies. System Levelized Cost of Electricity (System LCOE) is a metric to account for both integration and generation costs associated with a specific VRE technology [78]. The calculation of System LCOE requires an energy system model. Merely modeling one system state, such as the optimal cost of capacity mix and its dispatch, is inadequate. It is necessary to compare two electricity system states, one with increased VRE capacity and one without, in order to determine the system integration cost. The integration cost can be determined by adding up various cost components, including grid and balancing costs associated with the increased VRE capacity.

Cost of capital/ Discount rate

Cost of capital (CoC) refers to the minimum rate of return an investor needs to justify the costs of a project [82]. When it comes to the assessment of new projects or investments, CoC is often used as the discount rate to calculate the present value of future cash flows from a project or investment [83]. Thus, it is an important input parameter for evaluating the investment decisions for different energy technologies, which affects the cost-competitiveness of energy technologies and the overall electricity system cost. The transitioning towards carbon neutrality requires substantial investments in generation and transmission assets for the energy sector. VRE technologies are characterized with high capital expenditure (CAPEX) and little operational expenditure. The economics of a high CAPEX project, such as wind and solar, is especially sensitive to the CoC. For instance, doubling the CoC from 5% to 10% will increase the LCOE of wind and solar by more than 50%. The value of CoC varies across countries, technologies and over time [84, 85]. For energy technologies, CoC is affected by multiple drivers on the country level, sector level, financial sector level, and technology level [85].

On the country level, the CoC is typically affected by the overall country risk, which encompasses economic, political, and social instability. The country risk is closely linked to institutions, as institutions play a critical role in shaping a country's political, economic, and social environment,

which in turn affects the level of risk that businesses and investors face in that country [86, 87]. Strong and effective institutions can provide a stable environment, protect property rights, and enforce contracts, while weak or corrupt institutions can create an uncertain and risky business environment. In addition, macroeconomic policies and general financial market sentiments such as fear of defaults and credit crunches can also impact the level of risk across the entire economy [88, 89]. Notably, the country risk affects the CoC for all investments in a country.

At the sector level, the CoC is generally affected by the electricity market structure, policies and regulations specifically for the electricity sector, and the expected stability of such policies and regulations [90]. The market structure influences the potential price of the generated electricity and renewable energy support policy like feed-in tariff provides a guaranteed revenue stream for an extended period. Both market structure and support policies affect the expected return of a project, thus affecting the investment risk and CoC [91].

Factors at the financial sector level, such as the maturity of the financial sector, experience in financing energy technologies, and availability of concessional finance (e.g., subsidized loans), can also affect CoC [92]. A mature financial sector with diverse financing options can lead to increased competition and lower CoC. Experience in financing energy technologies can make investors more comfortable with risks and returns, resulting in lower CoC. Concessional finance, such as subsidized loans, can provide cheaper sources of funding and lower CoC.

Finally, the portfolio of generation technologies and fuels, emission intensity, and the maturity of new technologies are important factors at the technology level that can influence CoC [89, 93]. The availability, cost, and reliability of different technologies and fuels affect the risk and return of energy projects, which can impact CoC. Higher emission intensity may result in potential costs associated with carbon pricing or other policies aimed at reducing emissions [93]. The maturity of new technologies can affect the perceived risk and expected returns. Early-stage technologies may require higher CoC, while more mature technologies may attract lower CoC [89].

Methodology

The principal method used in this thesis is the energy system optimization model (ESOM) for long-term investment planning. ESOM is widely used to generate insights for policy analysis and decision making for the electricity system. This chapter starts with a general introduction to energy system models. It is followed by a detailed description of the model developed in this thesis. At last, the input data are summarized.

Energy system models

The energy system is a complex socio-technical system, such that the function and mechanism of the whole system are difficult to test and evaluate [94]. Energy system models are usually adopted to explore such a system [95, 96]. These models can show the potential energy system portfolios under different scenarios, considering resource availability, technology costs and developments, demand growth, and different energy and environmental policies [97-99]. In this thesis, we focus on the investments for future low-carbon electricity systems considering the changes in future electricity demand profile, availability of super grid and exclusion of nuclear power. To address these issues, we adopt energy system optimization models with the focus on capacity expansion as the investigation tool. An optimization model minimizes the electricity system cost, and the outcome is equivalent to that of a competitive market in which rational agents maximize their profits, even though our focus in this thesis is neither on the electricity market nor on agent behaviors.

An optimization model consists of three important parts: the goals to be met, the decisions to be made, and the constraints to be satisfied [100]. For the case of an energy system optimization model, a linear optimization approach is usually adopted to minimize the total system cost under resource, technology, environmental and policy constraints. The decision variables, which are the choices that need to be made, normally refer to the installed capacity for generation, storage, transmission, the amount of DSM, as well as the hourly dispatch. Some popular energy system optimization models include MARKAL [101, 102], TIMES [103] and PyPSA [104].

Historically, energy system models were developed primarily for the conventional electricity system. When it comes to the modeling of an electricity system with a high penetration of VRE, several challenges arise, one of which is the representation of variability in electricity generation [99, 105]. Two important factors are related to the variability of generation: the temporal and spatial resolutions [99]. For a system dominated by VRE, there might be extensive cooperation to allow the share of VRE and dispatchable resources via cross-border transmission grids in a large spatial scope. In addition, the electricity system might be integrated with other energy sectors to reduce the CO_2 emissions for the entire energy system. Furthermore, the transition

pathway towards the future low-carbon electricity system is not yet clear and different transition pathways might result in different final configurations for the electricity system. Last but not least, the discount rate, which reflects investment risks, varies between countries. It has a major impact on the competitiveness of VRE technologies characterized by high upfront investment costs. The setups in energy system models regarding these six aspects (temporal resolution, spatial resolution, spatial scope, sectors included, pathway and discount rate) can be influential on modeling results [98, 105], thus, affecting the system cost and capacity mix for the future electricity system. Therefore, in the following section, we characterize the energy system models along these six aspects.

Temporal resolution

Energy system models used to have a coarse temporal resolution, so as to ensure a reasonable solving time [99, 105]. Typically, these models use representative time-slices to represent a whole year [98, 99, 105, 106]. The representative time-slices might be sufficient for an energy system that is dominated by conventional thermal power plants, as the outputs of thermal power plants (e.g., coal and nuclear power plants) have little dependence upon fluctuating weather conditions [99]. An example of a model that uses representative time-slices is the TIMES model, in which 12 time-slices are used to represent the day, night and peak hours for four seasons in some studies [107, 108]. With this approach, the capacity factor of VRE follows the fixed temporal pattern of the representative days in a given time period (e.g., the same diurnal generation pattern for solar power in the summer). However, for an electricity system with a high penetration of VRE, the electricity generation varies over time depending on the weather conditions. The output of VRE (especially that of wind power) does not maintain the same temporal pattern. In this case, a small set of time-slices fails to capture the variation in generation for VRE, which may lead to an underestimation of the variability of VRE. Reichenberg and Hedenus [109] investigated the error induced by using representative periods in capacity expansion models and found that models using a temporal representation of 25–100 days predict system cost and total VRE capacities within a range of 10–20% deviation from the results based on an entire chronological year. Poncelet et al. [110] compared the impacts of different temporal resolutions on modeling outputs and showed that a low temporal resolution can overestimate the share of VRE in the generation mix by up to 7% and underestimate the operational cost by up to 53%. Similarly, several other studies [111-113] showed that a low temporal resolution may result in an overestimation of the penetration level of VRE in the electricity supply mix. These studies [109-113] highlighted the importance of applying a high temporal resolution for the appropriate representation of VRE technologies. Therefore, an hourly temporal resolution is adopted for the studies included in this thesis.

Spatial resolution

Spatial resolution refers to the degree to which the modeled regions are spatially aggregated. It affects the representation of an electricity system with a high penetration of VRE in two ways: (i) the representation of transmission and distribution grids; and (ii) the representation of VRE resources. With a coarse spatial resolution, there is an underestimation of the transmission and distribution cost if the subregions are treated as copper plates, and the transmission constraints inside each subregion cannot be adequately represented. For the neglected grid costs due to copper plate assumption, Brown et al. [8] reported that the grid cost accounts for a relatively low share of the total electricity system cost. Regarding transmission constraints, Frysztacki et al. [114] showed that a more detailed spatial resolution for the grid, which better captures the grid bottlenecks, increases the electricity system cost by up to 23% due to that investment in generation assets has to be constrained more to local sites with low-quality VRE resources. However, allowing for grid expansion may mitigate the impacts of grid bottlenecks and reduce the system cost by 16% compared to the case where transmission capacity is fixed.

In addition to the representation of grid, largely aggregated regions may fail to reflect the resource diversity for VRE, as the capacity factors for VRE are usually averaged over the subregion [115]. The supply potential and economic performance of VRE depend largely on the regional resource endowments. Moreover, the variations of VRE can be smoothed by locating the generation capacity in diverse geographic locations with different weather conditions and connecting them via transmission grids. Frysztacki et al. [114] explored the impact of different spatial resolutions for VRE resources on the electricity system design and found that, with a high spatial resolution, more generation capacity is installed on the sites with better output for VRE, which reduces the system costs by up to 10%. Similarly, both Frew and Jacobson [115] and Hörsch and Brown [116] showed that a more detailed spatial resolution allows the model to allocate more generation capacity to the sites with better VRE resources. The above studies used the optimization approach to choose the sites for VRE installations, which led to a prioritized utilization of sites with the best output for wind and solar. In such cases, a higher spatial resolution leads to lower cost of producing solar and wind power as the best sites can be distinguished and chosen by the model.

Spatial scope

The spatial scope refers to the boundary of the electricity system covered in the model. The spatial scope is important for evaluating the impact of international electricity trade [105]. In particular, electricity can be traded from regions where generators are currently capable of producing excess electricity to areas where the demand is currently not satisfied, which indicates the share of VRE and dispatchable resources over a large geographic area. Usually the integration of different electricity markets and institutional support from all the involved countries are needed to enable

cross-border electricity trade [117]. Many studies have evaluated the benefit of extending the spatial scope for electricity systems based on VRE [2, 22, 39, 40]. Schlachtberger et al. [3] compared the European electricity system with optimal interconnected transmission grids to a system in which all the countries are isolated from each other, and reported that isolating countries without international trade increases the electricity system cost by 30%. Similarly, Eriksen et al. [118] showed that the electricity system cost increases by 20% if cross-border electricity trade is not allowed. Likewise, Tröndle et al. [6] estimated that isolating countries for the sake of self-sufficiency at the national level increases the electricity system cost by 40%, as compared to a continent-wide electricity system in which both the VRE and dispatchable resources are shared. Pattupara and Kannan [119] incorporated international electricity trade revenue into the national electricity system cost and observed that international trade is important for the national system cost, as the trade revenue can offset the domestic investment cost. Therefore, it is important to include a large spatial scope in the model, given its influences on the electricity trade and system cost. One key implication that arises from this is the choice of spatial scope when investigating the national electricity system. One can look at the focused country in isolation, but this may underestimate the benefits of international cooperation for electricity trade via expanded transmission grids.

Given the large benefits of transmission grid expansion and trade at the continental level, it is interesting to understand whether such benefits would be further enhanced if transmission is extended to intercontinental connections. Reichenberg et al. [120] analyzed a Eurasian super grid between China, Mid-Asia and Europe and found that allowing for a super grid decreases the electricity system cost by up to 5%, compared to continental grid integration. Breyer et al. [121] evaluated the effect of integrating nine “major regions” of the world with a global super grid and reported that the cost benefit of doing so is 2%. Aghahosseini et al. [122] showed a cost reduction of 1.6% by integrating North America and South America. Bogdanov et al. [123] found a cost reduction of 1.3% by connecting Europe, Eurasia, Middle East and North Africa. The benefit of further connecting different continents with transmission grids seems to be rather limited compared with continental grid integration.

Sectors included

Electrification and electric fuels (power to fuel) are potential approaches to decarbonize energy sectors other than the electricity system. These strategies can be achieved through, for example, replacing fossil fuel-powered infrastructures with electric ones (e.g., combustion engine vehicle vs. electric vehicle). Currently, more energy system models are investigating sector-coupled energy systems with a high temporal resolution, such as PyPSA-Eur-Sec [124]. An integrated energy system, within which the electricity, heating, industrial, transport sectors, etc., are closely

linked, can abate more CO_2 emissions and may provide greater flexibility from the demand side [125-127]. Brown et al. [5] investigated an integrated electricity, heating, and transport system for Europe, and showed that sector coupling may increase the average electricity cost by 12% due to increased electricity demand compared with an electricity-only system; however, flexibilities accrued from the heating and transport sectors may reduce this cost by 17%. Similarly, Göransson et al. [128] estimated that the flexibilities obtained from the electrified steel industry and transport sector can reduce the electricity cost by 8% in Northern Europe, as compared to the case in which no flexibilities are provided. While these two studies [5, 128] assumed a certain level of sector coupling for the future energy system, it remains unclear as to what extent and in what way sector coupling will be implemented for the future energy system.

Pathway/Greenfield

In terms of the time horizon, energy system optimization models for capacity investment can analyze a single year (*Greenfield*) or a span of multiple years (*Pathway*) [98]. The *Greenfield* optimization approach is widely used to investigate the optimal configuration for the future electricity system, although it does not provide insights into how to transition towards such a system [129, 130]. In contrast, the *Pathway* approach has the advantage to analyze the evolution of the energy system over a long time period. Specifically, the *Pathway* approach can be utilized to investigate when certain technologies need to be installed to meet certain goals along the transition pathway and the corresponding impacts on the end-state of the energy system. Today's generation fleet and the decisions made in intermediate steps may affect the configuration of the future electricity system, as power plants typically have lifetimes of several decades [129, 130]. However, the dynamics along the energy transition pathway are usually not well captured by existing energy system models that focus on transition pathway. In addition, the transition pathway analysis is generally considered to lack sound theory support. Finally, the long time horizon and the introduction of non-linearities (learning, feedback effects, etc.) will lead to the escalation in computation time.

Regarding the transition pathway, it can be investigated through optimizing the entire transition process with perfect foresight or using the myopic optimization approach [98]. With perfect foresight, it is possible to evaluate the cost-effective transition pathway. By contrast, the myopic optimization approach optimizes the energy system for each time-step based on the results from the former time-step. This does not necessarily yield either a cost-effective transition pathway or a cost-effective final configuration for the energy system.

Uniform/Heterogeneous discount rate

ESOMs often characterize investment cost for a technology using an initial capital cost depreciated over the economic lifetime with the discount rate. These models typically assume the discount rate to be homogeneous for all the countries without considering the additional risk for less stable countries [38]. The discount rate is project-specific, and it varies significantly across countries and over time [83, 85]. The cost competitiveness of VRE projects with high upfront investment costs is strongly influenced by the discount rate [83-85]. Some studies [38, 90, 131-133] applied heterogenous discount rates to analyze the development of renewable energy in different countries and showed that renewables become more competitive in low-risk countries, while they are less so in high-risk countries. As for the investment planning for a future renewable energy system, Schyska and Kies [134] found that applying heterogeneous discount rates has a significant impact on the optimal energy system configuration by shifting investments in capital-intensive renewables to low-risk countries, compared to the case with a uniform discount rate. Therefore, it is clear the choice of discount rate (uniform or heterogeneous) has a strong impact on the regional capacity mix. It is important to take into account the regional difference in discount rate when it comes to the comparison of investment for different countries, especially countries across different investment risk classes [38].

The REX model

Two energy system models are applied to address the research questions of this thesis: the REX (Renewable Energy eXpansion) model developed by the author and the Supergrid model developed by Niclas Mattsson. The REX model is a cost optimization modeling tool for capacity investment and the dispatch of electricity generation, transmission and storage. It employs a Greenfield approach to identify the minimum cost portfolio for the future electricity system. This entails a linear optimization problem with the objective to minimize the total annual electricity system cost, given the constraints of meeting the electricity demand, the renewable energy resource potentials, and a CO_2 emissions cap. The main decision variables in the model comprise: installed capacity for generation, storage, and transmission; the level of demand-response; and the hourly dispatch. An overview of the model and the associated generation technology options and variation management strategies are depicted in Fig. 5.

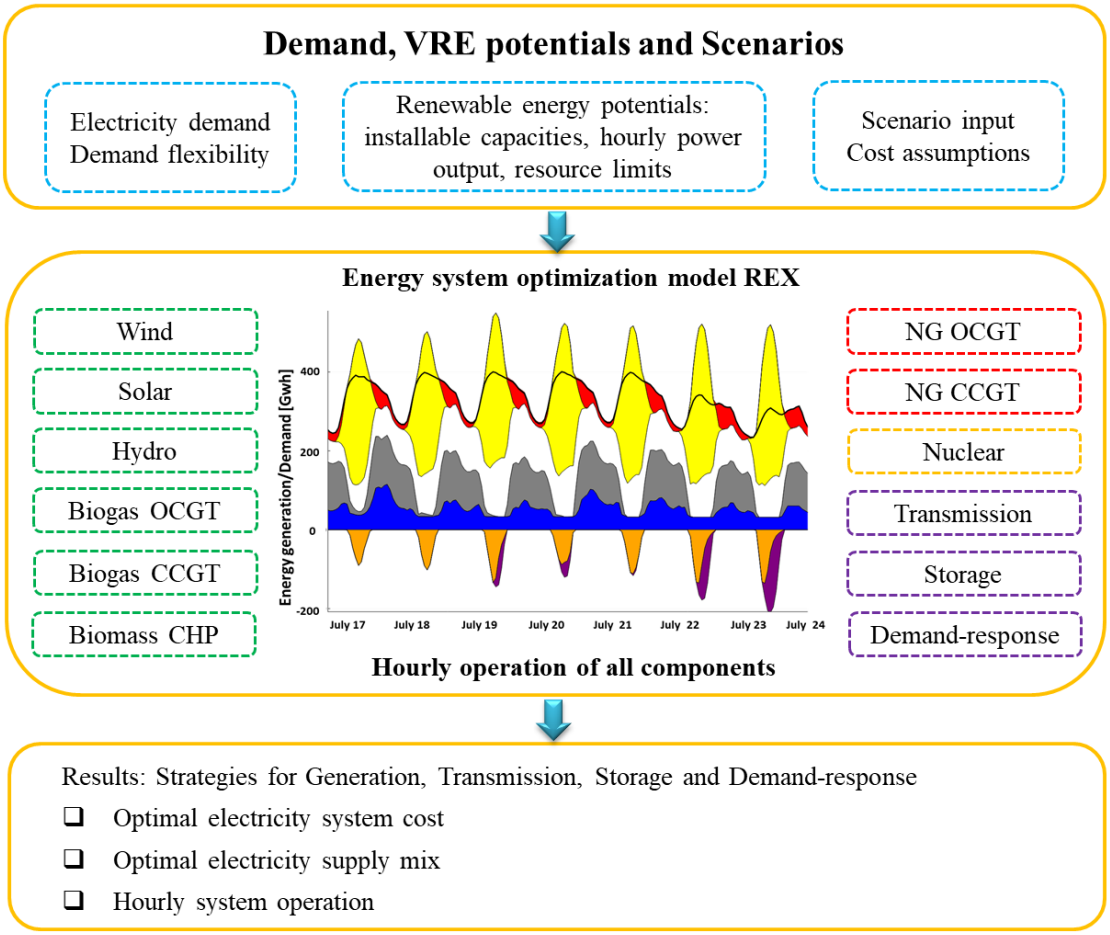

Fig. 5. Overview of the REX model. The dashed-line text boxes represent the: input data (blue); renewable generation technologies (green); fossil fuel-fired generation technologies (red); nuclear (orange) and variation management strategies (purple). OCGT, Open-cycle gas turbine; CCGT, combined-cycle gas turbine; NG, natural gas.

In the model, the nodes that represent the regions are labeled as *r*, *n* represents the electricity generation technology at the node, *m* represents the demand-response at the node, and *t* is the time of the year. The total annual system cost consists of the fixed annualized costs C_n for electricity generation capacity G_{rn}, fixed annualized costs $C^{storage}$ for electricity storage S_r, fixed annualized costs $C_{rr'}$ for transmission capacity $Z_{rr'}$, variable costs R_n for electricity generation g_{rnt} and variable costs R_m for demand-response d_{rmt}. For storage and transmission, the variable cost is assumed to be zero. Therefore, the objective function of this linear optimization problem is formulated as follows:

$$Min \sum_{r,n} C_n G_{rn} + \sum_{r} C^{storage} S_r + \sum_{r,r'} 0.5 C_{rr'} Z_{rr'} + \sum_{r,n,t} R_n g_{rnt} + \sum_{r,m,t} R_m d_{rmt}. \quad (2)$$

Since $Z_{rr'}$ and $Z_{r'r}$ represent the capacity for the same transmission line rr', a coefficient of 0.5 is incorporated into the transmission cost formula to avoid double counting.

The electricity demand has to be satisfied through generation, demand-response, trade and storage.

$$\sum_{n} g_{rnt} + \sum_{m} d_{rmt} + \sum_{r'} (\eta_{\gamma}\, \gamma_{r'rt} - \gamma_{rr't}) + \ (\eta_s \alpha_{rt} - \beta_{rt}) \geq D_{rt}\,, \tag{3}$$

where g_{rnt} is the electricity generation, d_{rmt} is the demand-response, $\gamma_{rr't}$ is the electricity traded from node r to node r', η_{γ} is the efficiency of transmission, α_{rt} is the discharge from storage, β_{rt} is the charge into storage, η_s is the round-trip efficiency of storage, and D_{rt} is the hourly electricity demand. The model was implemented in Julia using the framework JuMP [135] and was optimized using the Gurobi solver [136].

The Supergrid model

The Supergrid model is a generic electricity system model for capacity expansion [137]. Similar to the REX model, it optimizes investment and dispatch for the electricity sector with hourly time resolution [138]. Unlike the REX model where hydropower capacity is fixed at the current level, new hydro power is also an investment option in the Supergrid model. The regional potentials and costs for hydropower are estimated with the GlobalEnergyGIS package [137]. In addition, the Supergrid model has the advantage to directly accept renewable potentials, hourly capacity factors and hourly synthetic electricity demand produced by GlobalEnergyGIS. It can be quickly run for arbitrary region setups.

In this model, the transmission cost is distinguished between onshore and offshore grids. There is also an additional cost for exploiting wind and solar sites located far from the grid proxy. Detailed description of model equations and constraints are listed in the supplementary material of Mattsson et al. [137]. The Supergrid model is also written in Julia and can be solved using both CPLEX and Gurobi solvers [136, 139].

Estimation of power generation from wind and solar

The power generation from wind and solar is dependent on weather conditions (wind speed and solar radiation). The capacity factor is usually used to represent the power generation from wind and solar relative to the theoretical maximum output over a given period. For studies in this thesis, we calculate the hourly capacity factor for wind and solar for one entire year to capture the seasonal and diurnal variability of wind and solar.

Wind speed is the key input for the calculation of wind capacity factor and wind power. The ERA5 reanalysis data (hourly wind speed) provides an accurate estimate of the hour-to-hour variation in wind speed (wind profile) for the entire world [140]. However, the spatial resolution (31 km × 31 km) of ERA5 data is rather low, which cannot capture the heterogeneity in wind speed within a small geographical area [138]. By comparison, the Global Wind Atlas (GWA)

[141] modeled the annual average wind speed with a more detailed spatial resolution (1 km × 1 km). In this thesis, we combine the ERA5 dataset (wind profile) and the GWA dataset (annual average wind speed). Each small pixel (with a size same as that in GWA, 1 km × 1 km) is provided with the wind profile from the corresponding larger pixel in ERA5, and the wind profile is then scaled using the average wind speed in GWA. By doing so, we obtain an hourly time series of wind speed that captures geographical variations in wind output caused by local differences in topography and land cover at a spatial resolution of 1 km (compared to 31 km for ERA5). The instantaneous wind speeds are then converted into capacity factors using the output profile of the 3 MW Vestas V112 wind turbine (Fig. 6) [138].

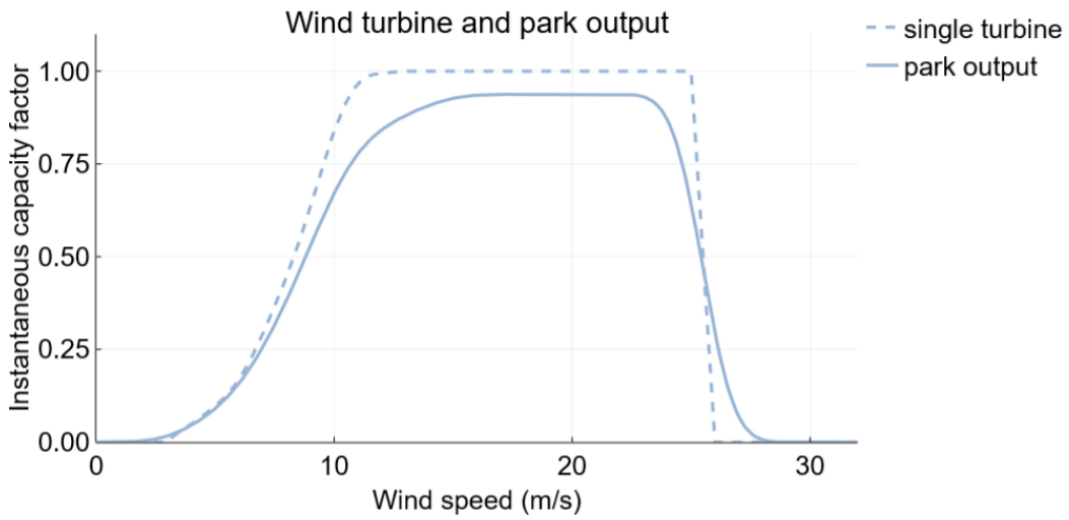

Fig. 6. The output profile of the 3 MW Vestas V112 wind turbine and wind park.

The solar capacity factor is estimated based on the ERA5 "surface solar radiation downwards" and "total sky direct solar radiation at surface" [142]. Given that solar radiation is rather stable within a certain geographical area (compared with the heterogeneity in wind speed), the calculated solar capacity factor based on ERA5 for each large pixel (31 km) is then provided to the corresponding small pixels (1 km). In this way, the spatial resolution for solar capacity factor is consistent with wind capacity factor. The calculated wind and solar capacity factors are then used to estimate the wind and solar cost for each pixel (1 km) and the supply curve for each subregion.

Main input data

For **Papers I** and **V**, we use historical electricity demand as input to the model. The data are taken from ENTSO-E [143] for year 2014. For **Paper I**, the electricity demand data are treated to display typical seasonal and diurnal demand patterns, but the volume of the electricity demand remains constant. For **Papers II**, **III** and **IV**, since historical electricity demand is not available for most of the investigated regions, we use synthetic demand estimated by GlobalEnergyGIS package [137]. First, it calculates the annual electricity consumption based on the Shared Socioeconomic

Pathway scenarios. Second, it estimates the hourly demand profile based on a machine learning approach, which adopts historical demand profiles for 44 countries as input to a gradient boosting regression model [144] to calculate the hourly demand. The regression model takes into account the calendar effects (e.g., hour of day, weekday and weekend), temperature (e.g., hourly temperature in the most populated areas of each region), and economic indicators (e.g., local GDP per capita). The hourly demand series is then scaled to match the annual electricity demand. For all the studies, the electricity demand is assumed to be inelastic.

For **Papers I** and **V**, the geographic regions covered are the EU-28 countries (excluding Cyprus and Malta) plus Switzerland, Norway, Serbia, Bosnia and Herzegovina, North Macedonia, and Montenegro. An example of the transmission network topology is shown in Fig. 7. For **Paper II**, we explore seven different regions in the tropical and subtropical zones: Spain, South China, South India, West Saudi Arabia, North Nigeria, East Brazil, Malaysia. In **Paper III**, we look into the entire world. For **Paper IV**, we model six large regions across the world: Australia, South Asia, Middle East and North Africa, Central and South Europe, South America, Central and North America.

For **Papers I** and **V**, the CO_2 emission constraint is 10 g/kWh, which is equivalent to a 98% reduction in CO_2 emissions compared with the 1990 average for the electricity sector in Europe. For **Papers II,** five progressively more stringent CO_2 emission targets (from 200 to 10 g/kWh) are applied. In **Paper III** we assume a pure renewable future. For **Paper IV**, the CO_2 emission constraint is 1 g/kWh, which represents a nearly zero emission electricity system.

The input data for VRE is calculated based on the GlobalEnergyGIS package developed by Mattsson et al. [137]. To capture more effectively the variability in weather conditions and represent the corresponding capacity factors for wind and solar power, the wind and solar technologies in each subregion are divided into five classes based on resource quality. For the base scenario of each study, the data for VRE profiles are based on the data source in year 2018. The available land for wind and solar installation is given as a percentage of the suitable land, namely the total land less the areas which are not suitable for large-scale wind and solar power plants, e.g., areas with high population density, forest or protected area, too deep water (for offshore wind). Regarding land availability for wind power, various assumptions are made in the literature [145], but there is limited empirical evidence to support these assumptions [146]. Hedenus et al. [146] found that wind turbines have been constructed on various types of land, with up to 20% of land used for wind power in some US counties. Given the differences in institutional frameworks between countries, assumptions about where to deploy wind and solar power should ideally be country specific. However, since no such analyses have been conducted, we simply assume that wind may be deployed on all types of land, but that a maximum of 10%

of the land may be exploited for wind power purposes (**Papers I**, **III** and **IV**). A lower land availability for wind power (8%) is assumed for Papers **II** and **V**. As there is less information on where and how much solar power can be built, we adopt a more conservative approach and assume that a maximum of 5% of suitable land is available for solar PV installations (**Papers II**, **III**, **IV** and **V**). For **Paper I**, we assume a larger land availability for solar power (6%) to avoid potential impacts of land scarcity on electricity system cost. For **Papers I**, **III** and **IV**, a population density threshold of 150 persons/km^2 is adopted, the same as that in [137]. For **Paper V**, the population density threshold is scaled down to 75 persons/km^2 to represent a more conservative estimate on the potential contribution from VRE resources. For **Paper II**, since most of the investigated regions are characterized with high population density, a population density threshold of 500 persons/km^2 is applied. The assumptions about the key technologies are listed in Table 1.

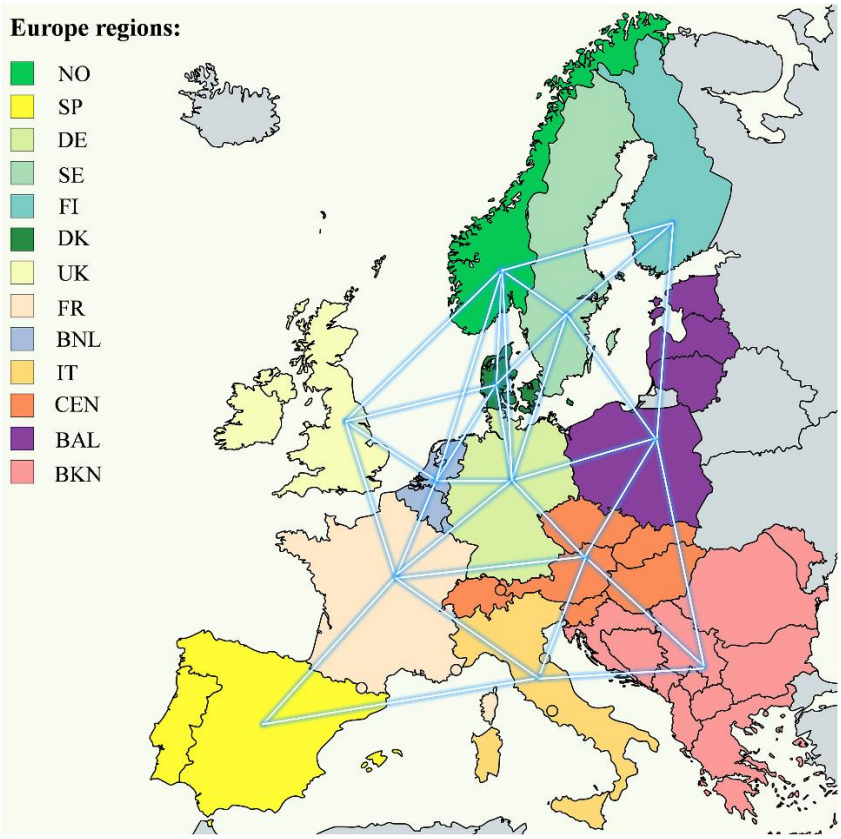

Fig. 7. An example of the regions and transmission network used in the REX model (**Paper I**).

Table 1 Assumptions made regarding the key technologies in the model.

Technology	**Assumptions**
Transmission (all papers)	Transport model, Copper plate for subregion
Biogas (all papers)	Fuel supply: maximum 5% of the annual electricity consumption
Biomass (**Paper V**)	Fuel consumption and capacity kept at the current level Electricity production follows the heat demand pattern in 2014
Storage (all papers)	Battery cost is used as the reference
Hydropower (**Papers I** and **V**)	No pumped hydropower Capacity is kept at the current level Capacity data are taken from ENTSO-E statistics [147] Inflow for 2013 is taken from Ref. [3] Minimum environmental flow [61, 62] for hydro reservoir: hourly environmental flow is ≥5% of the average hourly inflow to the reservoir
Hydropower (**Papers II, III** and **IV**)	No pumped hydropower Capacity is kept at the current level Existing capacity for hydropower, reservoir size and monthly inflow are obtained from [148-150]. Due to lack of data for some regions, the reservoir capacity is assumed to be equivalent to six weeks of peak hydropower production. For regions where storage and run-of-river plants could not be distinguished due to lack of data, we assume that at least 40% of hourly water inflow must be used for electricity generation to limit the flexibility provided by hydropower. The regional potentials and costs for new hydropower are estimated with GlobalEnergyGIS [137].
Demand-response (**Papers I** and **V**)	In a given time period, the aggregated consumers can curtail up to 5% of the demand at a given cost.
Population density threshold (all papers)	150 persons/km^2 (**Papers I**, **III** and **IV**), 75 persons/km^2 (**Paper V**), 500 persons/km^2 (**Paper II**).
Wind onshore (all papers)	Density: 5 W/m^2 Available land: 8% (**Papers II** and **V**), 10% (**Paper I**, **III** and **IV**)
Wind offshore (all papers)	Density: 8 W/m^2 Available land: 33% (**Papers I**, **II**, **V**), 10% (**Paper III** and **IV**)
Solar PV (all papers)	Density: 45 W/m^2 Available land: 5% (**Papers II**, **III**, **IV** and **V**), 6% (**Paper I**)

Results

This chapter presents a comprehensive summary of the main results from the appended papers [133, 151-153], providing an overview of the motivation, research questions, methods, and key findings for each study. Furthermore, this chapter delves into the methodology choices and the limitations of this thesis. This chapter concludes with a reflection section that underscores the insights and contributions of the research as a whole, highlighting its implications for both modeling practice and policymaking in the development of a low-carbon electricity system.

Impacts of the electricity demand pattern on the electricity system (Paper I)

Motivation and research question

Several studies in the literature suggested that the future electricity demand patterns may entail large changes in both diurnal and seasonal variations as the results of climate change, massive adoption of electric vehicles, electric heating, electric cooling, etc. [12-21]. However, many studies that investigate the future energy system with energy system models either used the historical demand profile or linearly scaled it up to project future electricity demand [12-21]. It remains unknown as how the potential electricity demand patterns will affect the cost and supply mix of the future electricity system. In particular, it is unclear if misleading results will be produced if energy system modelers use historical electricity demand profiles as inputs to the energy system models. Therefore, we evaluate the conditions under which a demand pattern is important for the modeling results. Specifically, we address the following research question: *What are the effects on the system cost and the electricity supply mix of applying different demand patterns in energy system models?*

Methods

To answer this question, we use a simple techno-economic cost optimization model with a high temporal resolution for the electricity system. The influences of different demand patterns are initially explored in a stylized case involving three interconnected regions with different VRE resource endowments in Europe (Fig. 8). The interconnected electricity system in the stylized case is modeled for one year with an hourly time resolution, under a cap on CO_2 emissions expressed in grams of CO_2 per kWh of electricity demand. The effects of different demand patterns on the system cost and the electricity supply mix are analyzed based on the modeling results. The REX model is then adopted to evaluate the European electricity system, to validate the results obtained from the stylized case. For both the stylized case and the case of Europe, the electricity demand profiles are treated to display typical seasonal and diurnal demand patterns (Fig. 9).

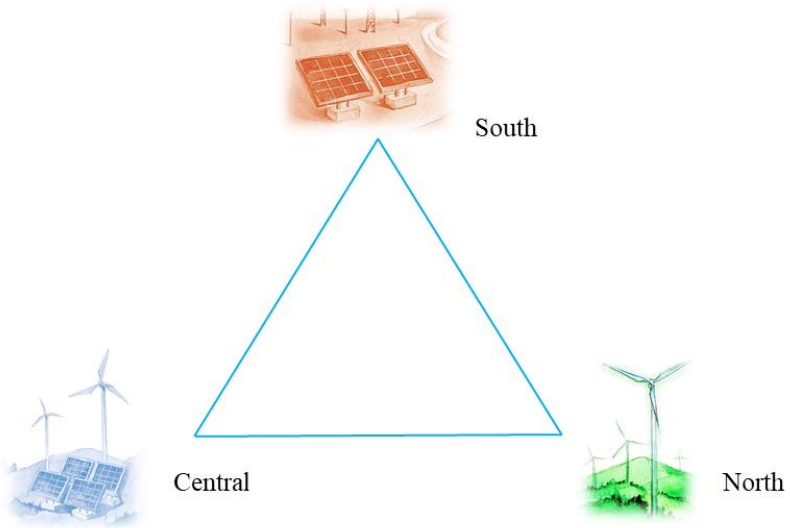

Fig. 8. Regions covered in the stylized case. We select three regions with typical VRE resource potentials and connect them with transmission grids to analyze the impacts of demand pattern on an interconnected electricity system. The three regions are located in the south, central and north of Europe, respectively, and they are accordingly labeled as South, Central and North. The data on VRE resources and the electricity demand pattern for Spain plus Portugal are assigned to region South. Similarly, data on VRE resources and the electricity demand patterns for Germany and Norway are assigned to regions Central and North, respectively.

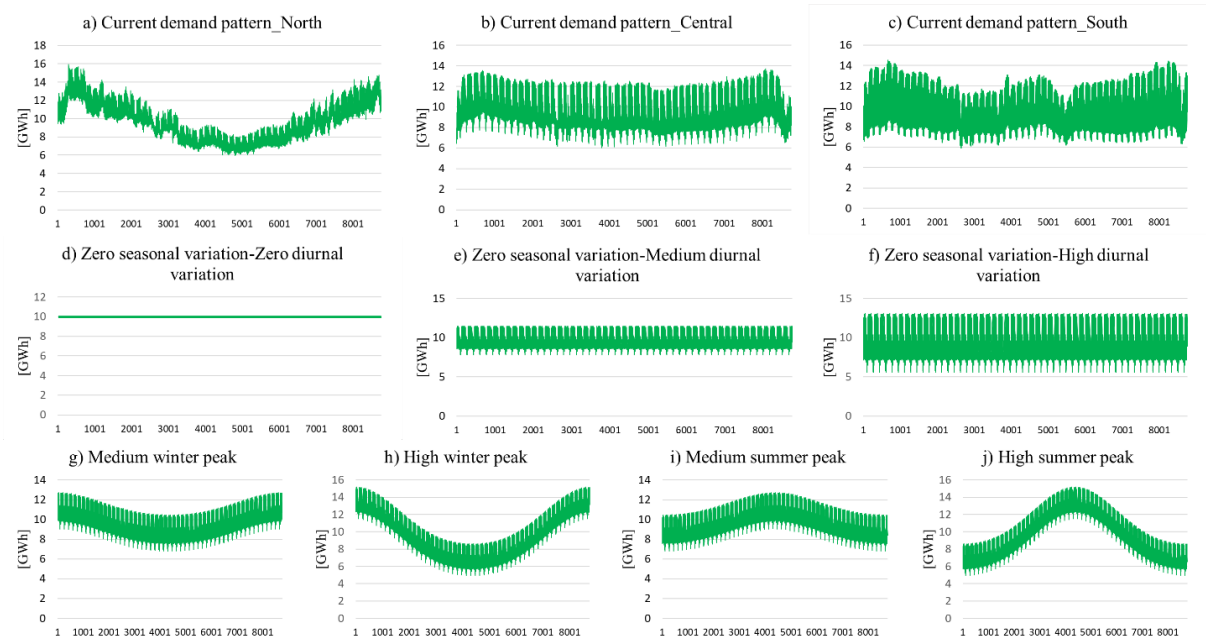

Fig. 9. Typical electricity demand patterns.

Main findings

Results for the stylized case

Fig. 10 shows how the average electricity system cost increases for scenarios with different seasonal variations, as compared to the scenario of the current demand pattern. If the demand profile has no seasonal variation or a winter peak (possibly due to large-scale deployment of electric heating), the increase in system cost is small (<3%). In contrast, the increase in system cost is larger (3%–8%) if the annual peak is in the summer (possibly due to massive adoption of ACs). In the stylized case, onshore wind power is cheap to install, and wind power has a typical seasonality with higher output in the wintertime than in the summertime. In addition, the variation of large-scale wind power can be smoothed through the expansion of transmission grids. Therefore, when the annual peak of the electricity demand is during the winter, the seasonal variation of the demand profile is in line with the seasonal pattern of wind power, and the cheap wind resource is deployed. In contrast, if the annual peak demand is in summer when the output of wind power is lower, the optimal system configuration comprises more solar power and storage, which drives up the system cost. Correspondingly, there are large deviations in the capacity mix for the optimal electricity system portfolio, especially with respect to the solar and storage capacities (see Fig. 11). In the scenario with the highest summer peak, the increase in system cost is 8%, while the investments in solar power and storage capacities increase by 54% and 95%, respectively, as compared to the scenario of the current demand pattern. Similar phenomena are observed for other scenarios. Therefore, it is clear that a change in the seasonal demand pattern has a stronger impact on the electricity supply mix than on the system cost.

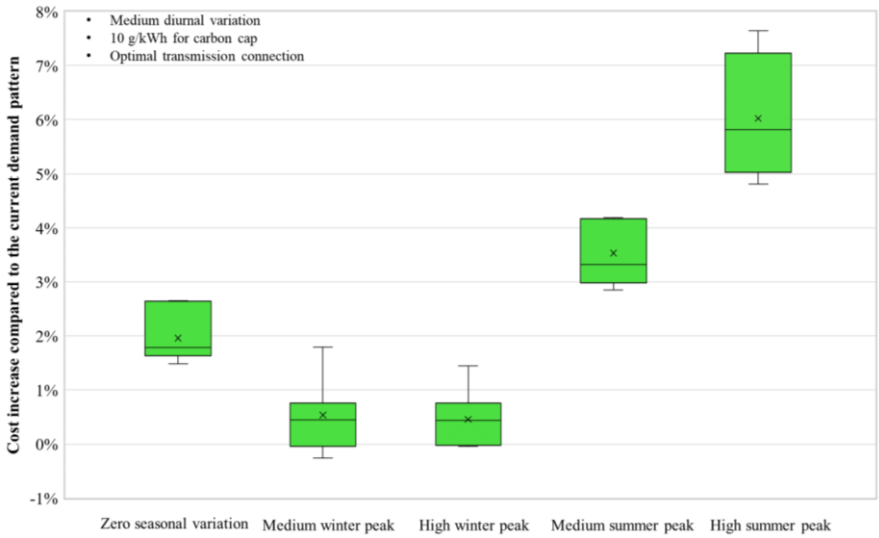

Fig. 10. Increases in the average electricity system cost for the scenarios of different seasonal variations, as compared to the scenario of the current demand pattern. Each seasonal demand pattern (label on the *x*-axis) represents a group of scenarios with the same or similar aggregated demand profiles for the three regions in the stylized case. The ends of the box are the upper and lower quartiles, so the box spans the interquartile

range. The bar in the box represents the median value and the cross represents the average value. The whiskers are the two lines outside the box that extend to the highest and lowest values.

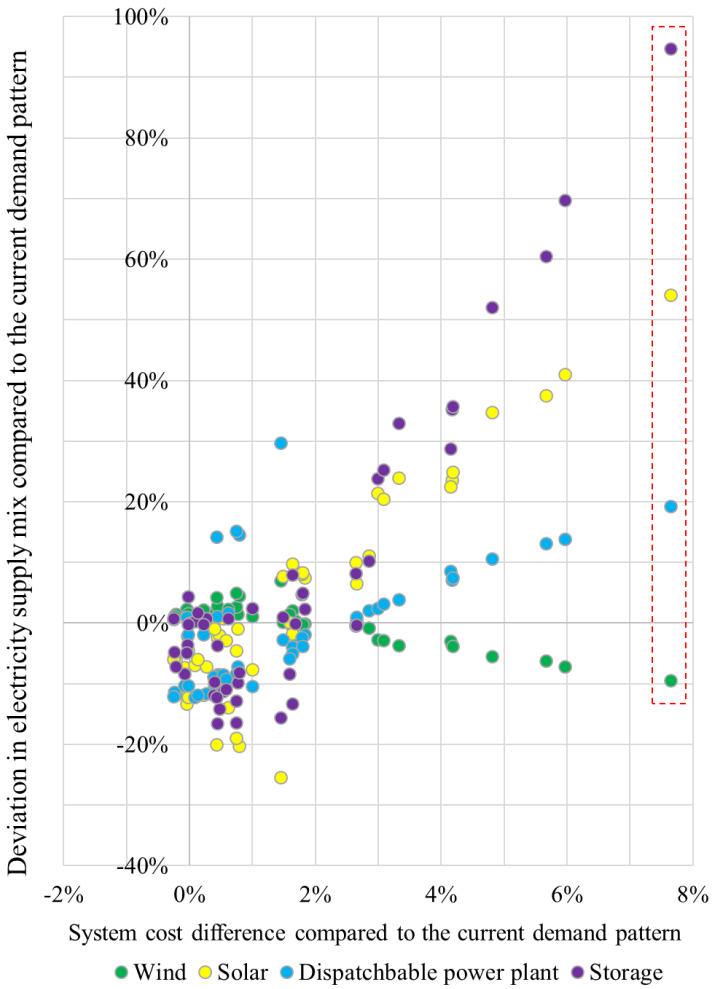

Fig. 11. Relationships between the differences in system cost and the deviations in the electricity supply mix for the scenarios of different seasonal variations, as compared to the scenario of the current demand pattern. The dots inside the red dashed rectangle represent the scenario with the highest summer peak, as described in the text.

The impacts of different diurnal demand patterns (the underlying causes of which may be various charging strategies for EVs) of the demand profile on the electricity system cost are rather limited. Across all the scenarios, a higher diurnal variation slightly increases the system cost, but the difference in system cost between the cases of medium- and high-diurnal variation is limited (<3%). Similar to the impact seen for the seasonal demand pattern, a higher diurnal variation has a more potent impact on the electricity supply mix than on the system cost.

Results for the case of Europe

We also analyze one full-scale case for Europe, to validate the results from the stylized case. As for the case of Europe, the system cost increase for scenarios with zero seasonal variation and a

winter peak is less than 2%, while the summer peak increases the system cost by 8%. The cost deviation due to different seasonal demand patterns for Europe is in line with the results from the stylized case. Therefore, our results regarding the impacts of different seasonal demand patterns based on the stylized case are valid for Europe.

Conclusions

Through investigating the impacts of different demand patterns on the modeling results for a stylized case and an applied case, we show in **Paper I** how the demand pattern influences the electricity system cost and the electricity supply mix.

- In general, the seasonal demand pattern (zero seasonal variation, winter peak) has a limited impact on the system cost, except for the case of the summer peak, where the system cost may increase by up to 8%;
- A higher diurnal variation has minor impacts on the system cost (<3% increase in the system cost);
- The electricity demand pattern has a stronger influence on the electricity supply mix than on the system cost;
- The impacts of different seasonal demand patterns on a European highly renewable electricity system are consistent with the results of the stylized case.

Impacts of electric cooling on the cost-optimal investment in solar PV (Paper II)

Motivation and research question

With the rapid growth of the world population and income, as well as the expected increase in temperature due to global warming, the global electricity consumption for space cooling is estimated to increase significantly in the coming decades. The increase in cooling demand, which is estimated to occur mainly in developing countries located in hot-climate regions due to the increasing use of air conditioners, will entail higher electricity consumption, requiring investments in new generation capacity. Both the demand for cooling and the output of solar photovoltaic (PV) are ultimately driven by solar irradiation, and therefore correlated in time. In this study, we investigate whether the synergy between the temporal behavior of the cooling demand and PV production makes solar PV more cost-effective or less so. Specifically, we address the following research question: *How does electric cooling affect the cost-optimal investment in solar PV for the future electricity system?*

Methods

In this study, seven regions located in the tropical and subtropical zones with potentially high demand for residential air-conditioning are investigated using the REX model. The electricity system with and without electric cooling for the residential sector is modeled with hourly time resolution, given CO_2 emission limits in the range of 200–10 gCO_2 per kWh of electricity demand. By comparing the optimal generation capacity mix for a system with electric cooling to a system without electric cooling, we are able to trace the impact of electric cooling on the cost-optimal investment in solar PV and other electricity generation technologies. Here, we use the term 'Case-Cooling' to refer to the system that includes residential cooling, and the term 'Case-No cooling' to refer to the system without residential cooling. The additional electricity supply mix due to the provision of residential cooling is obtained by calculating the difference in optimal generation capacity mix between the Case-Cooling and Case-No cooling. The overview of the method is presented in Fig. 12.

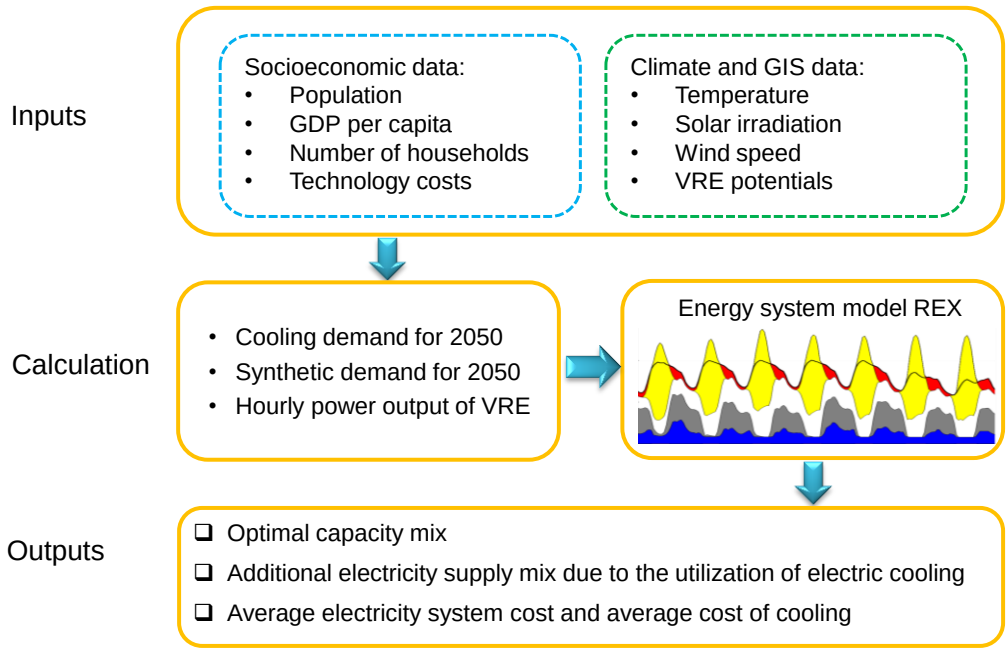

Fig. 12. Overview of the method. The dashed-line text boxes represent the: Socioeconomic data (blue); Climate and GIS data (green). VRE, variable renewable energy; GIS, Geographic Information Systems.

Main findings

Impact of electric cooling on solar PV investment

As is apparent from Fig. 13, across a wide range of geographic locations and CO_2 emission limits, adding electric cooling (Case-Cooling) consistently increases the share of solar PV in the optimal capacity mix, as compared to the case without electric cooling (Case-No cooling). The exact increase in the share of solar PV due to electric cooling varies depending on the region and the emission limit. The largest increase (12%) is estimated for North Nigeria (*NigeriaN*), possibly

because it has the highest cooling demand share (23%) (of the total electricity demand) and the best conditions for solar irradiation of all the modeled regions.

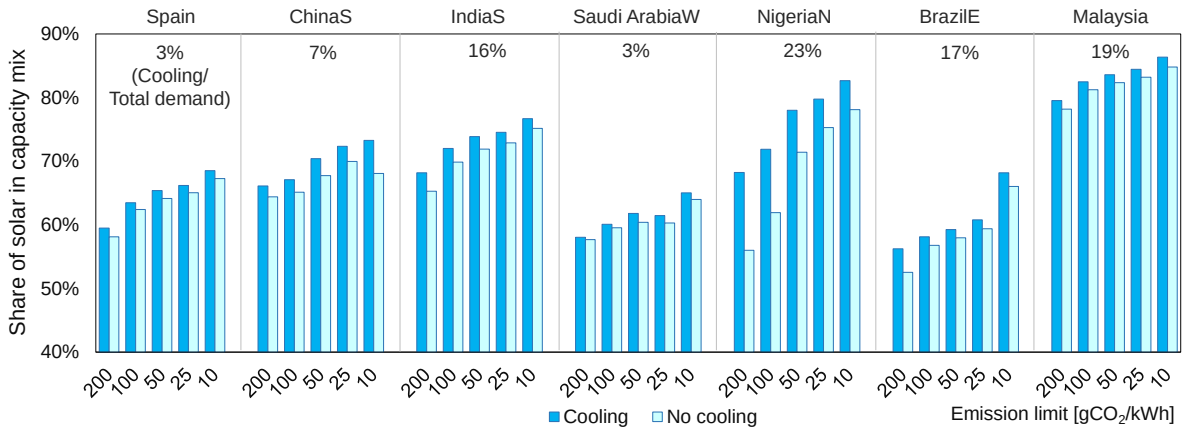

Fig. 13. The share of solar PV in the optimal capacity mix for the modeled regions under different carbon emission limits. The percentage listed on top of the bars is the cooling demand share of the total electricity demand.

Additional electricity supply mix due to cooling

To further understand the change in the optimal capacity mix due to electric cooling, we calculate the additional electricity supply mix for each region. Thus, we are able to analyze which technologies are added to meet the higher demand for Case-Cooling. As shown in Fig. 14, despite the wide range of geographic locations and emission limits, the additional electricity supply mix is dominated by solar PV in all the regions studied. Specifically, the share of solar PV in the additional electricity supply mix ranges from 64% to 135%. The reason why the share of solar PV exceeds 100% for some scenarios is that the change in the electricity demand profile due to cooling allows solar PV to substitute other generation technologies that exist in the optimal capacity mix for Case-No cooling. Note that even with a less-stringent emission limit, solar PV persists as the chief generation technology in the additional electricity supply mix. This implies that solar PV is the most competitive generation technology for powering cooling in both renewable and semi-renewable electricity systems.

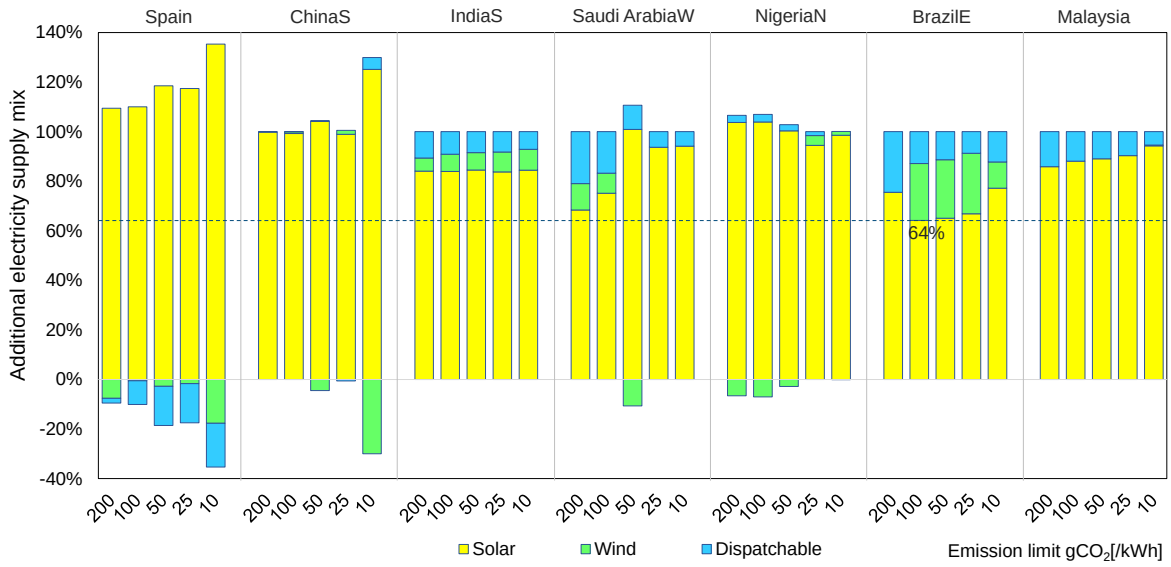

Fig. 14. The additional electricity supply mix for Case-Cooling versus Case-No cooling. The additional electricity supply mix is obtained by calculating the difference in the optimal capacity mix between Case-Cooling and Case-No cooling.

Conclusions

In this paper, we evaluate the cost-optimal investment in solar PV due to the adoption of electric cooling. By investigating seven different regions in the tropical and sub-tropical zones under different emission limits, we show that solar PV is the most cost-optimal generation technology for meeting the increased electricity demand from cooling. The share of solar PV in the additional electricity supply for cooling ranges from 64% to 135% across the seven regions. These results indicate that solar PV can serve as the cornerstone of the electricity supply for cooling in countries located in the tropical and sub-tropical regions.

Regional renewable energy cost and potential for trade (Paper III)

Motivation and research question

There are plenty of studies exploring global wind and solar energy potential [145], but only a few investigate global potentials beyond the technical potential. The regional heterogeneity of renewable resource endowments may influence future energy costs. Yet, extracting these resources also depends on local socio-economic conditions. We take steps towards a more realistic assessment of renewable resource potential by incorporating country-specific discount rates, domestic electricity demand and land-use requirements into the LCOE metric. By doing so, *we aim to measure a country's potential for renewable self-sufficiency and export*. Note that in this study, the renewable resources examined are wind, solar and hydropower.

Methods

In this study, to assess the import/export potential of countries, we introduce a novel metric, **Renewable LCOE available for export** ($RLCOE_{Ex}$), which incorporates both quality and quantity of the resource. $RLCOE_{Ex}$ is a measure of the marginal cost for a country to supply its entire electricity demand using only domestic renewable resources (VRE plus existing hydropower) (Fig. 15). For example: if a country has an annual electricity demand of 100 TWh and an annual generation of hydropower of 20 TWh, $RLCOE_{Ex}$ is found by sorting VRE belonging to that country from low to high cost until the total generation is 80 TWh. $RLCOE_{Ex}$ is the levelized cost of the last unit of VRE necessary to reach a generation equal to the annual demand.

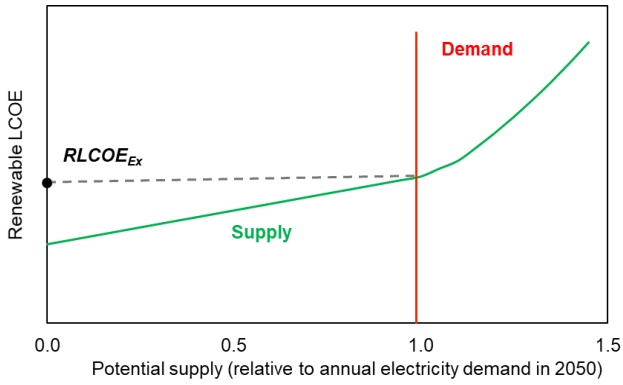

Fig. 15. A schematic diagram of the supply curve for renewable energy and the Renewable LCOE available for export ($RLCOE_{Ex}$). The electricity demand used for the calculation of $RLCOE_{Ex}$ is the total domestic electricity demand less the electricity generation from hydropower.

Main findings

Fig. 16 shows $RLCOE_{Ex}$ for most countries in 2050 based on the country-specific discount rates in 2021. Saudi Arabia, Chile, Morocco and the majority of the US, China, Mexico, Brazil and Australia show relatively low $RLCOE_{Ex}$ values, and thereby are potential exporters of renewable energy. The export possibilities are especially favorable for China, where neighboring countries display high $RLCOE_{Ex}$, or, in the case of Japan and South Korea, are unable to meet their demands using domestic resources.

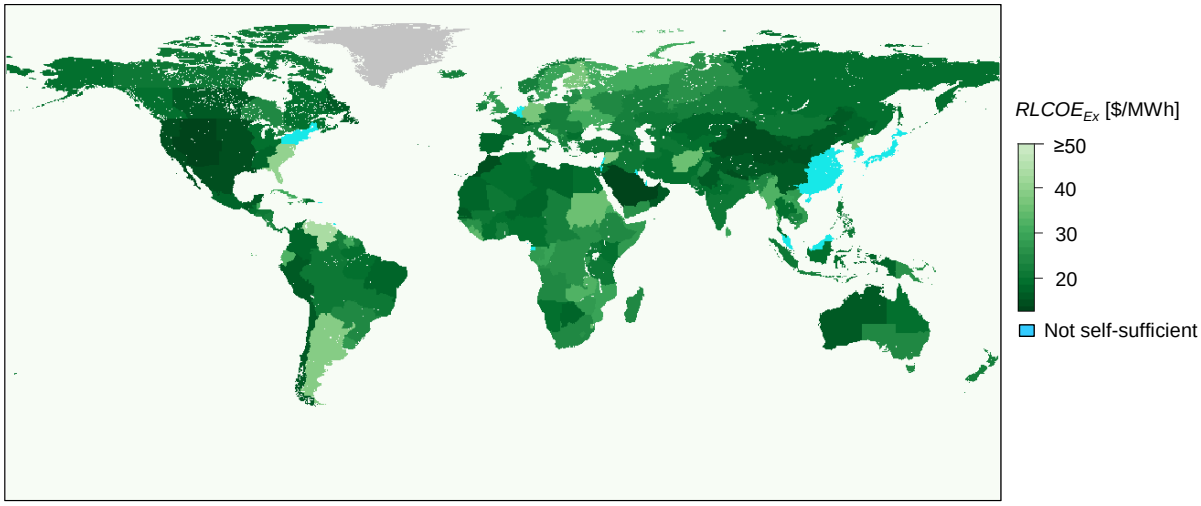

Fig. 16. $RLCOE_{Ex}$ for 2050. $RLCOE_{Ex}$ is estimated for most countries in the world, given projected demand in 2050 and with current country-specific discount rates.

Fig. 17 shows the $RLCOE_{Ex}$ for some selected countries sorted from low to high. For many countries in the world, the $RLCOE_{Ex}$ is below 20 $/MWh with the lowest cost reaching 13 $/MWh. In stark contrast, some countries are not self-sufficient or have a $RLCOE_{Ex}$ greater than 35 $/MWh. The large number of countries with comparably low $RLCOE_{Ex}$ provides plenty of electricity trade options for countries with insufficient renewable resources. There are already trade agreements for Saudi Arabia, Chile and Australia to export hydrogen to Germany, Japan and Netherlands [154].

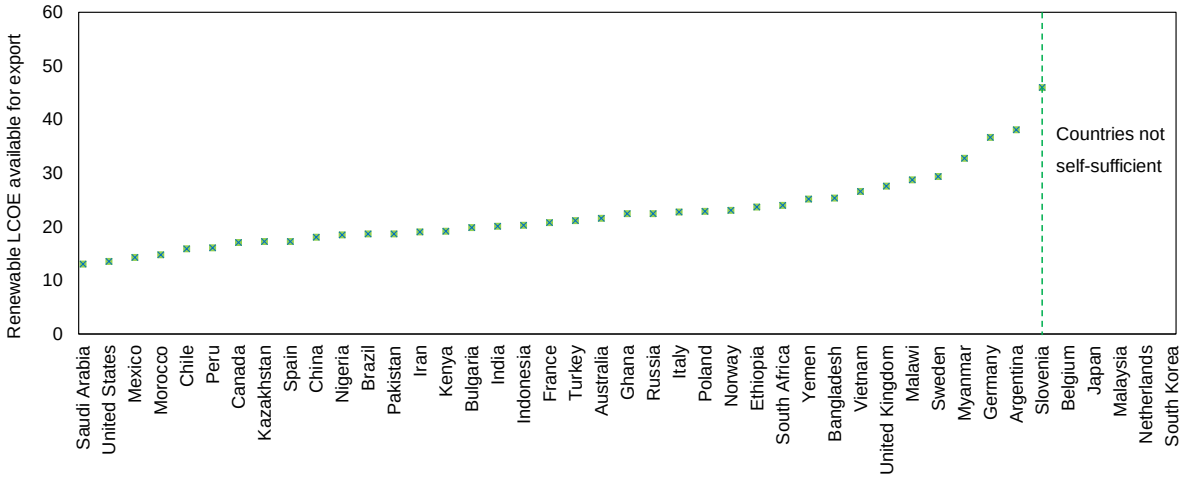

Fig. 17. $RLCOE_{Ex}$ for selected countries in 2050 to illustrate the global heterogeneity.

For the base case, we evaluate the $RLCOE_{Ex}$ for each country using the projected electricity demand in the SSP2 scenario [155] for 2050. To account for potential large-scale electrification and electro-fuel production for energy sectors other than the electricity system, we double the electricity demand for each country and reassess the $RLCOE_{Ex}$. At these demand levels, $RLCOE_{Ex}$ also increases, and more regions are not able to be self-sufficient, see Fig. 18. Specifically, most

European countries show relatively high $RLCOE_{Ex}$ with 9 countries, including Germany, the UK and Italy, unable to meet electricity demand with domestic renewable resources. A similar phenomenon is observed in East and Southeast Asia where Japan, South Korea, Vietnam, Malaysia and Singapore might import energy to meet domestic demand in the renewable future. Fig. 18 also shows the $RLCOE_{Ex}$ for an optimistic future where countries with the highest discount rates today evolve socio-politically such that their risk premiums decline over time. In a future in which all countries' investment costs revert to a low-risk mean, the $RLCOE_{Ex}$ is rather low for most of the world, except that some regions are not self-sufficient due to the lack of suitable land for wind and solar PV installations.

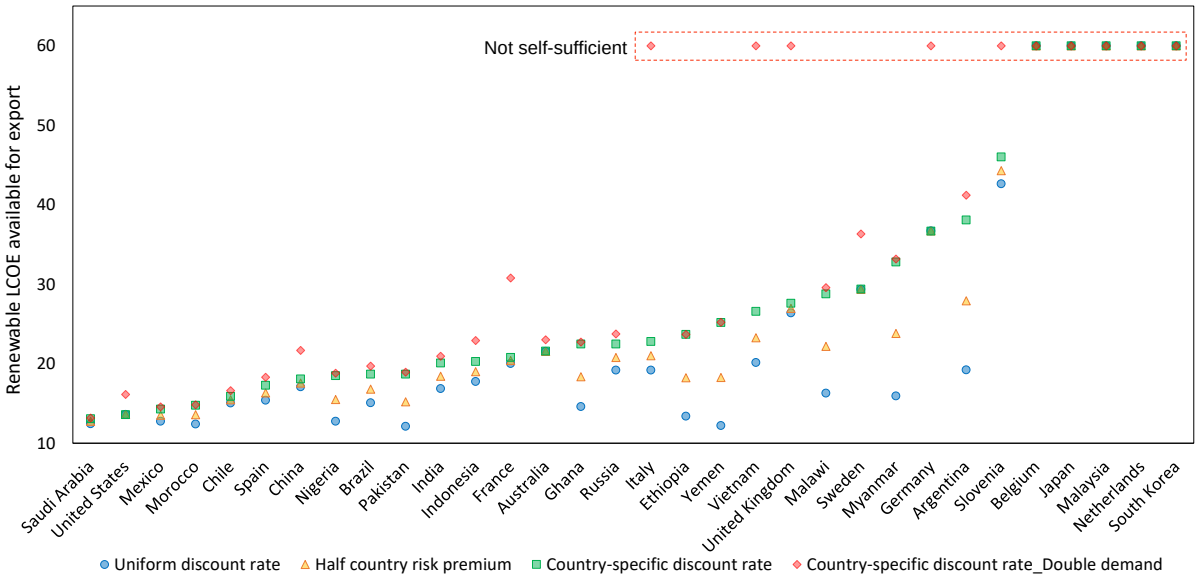

Fig. 18. $RLCOE_{Ex}$ for select countries under higher domestic electricity demand and various discount rates.

Conclusions

In this study we evaluate the global renewable energy potential while taking into account heterogeneous discount rates, electricity demand and land-use requirements. The results show that many countries can be self-sufficient at a low cost (< 20 $/MWh), while some countries have a $RLCOE_{Ex}$ greater than 35 $/MWh or cannot be self-sufficient with domestic renewable resources. Countries that stand out as having large potential for export of renewable energy include the US, China and Saudi Arabia. In addition, we find that the heterogeneity in discount rates greatly influences the renewable energy cost.

Impacts of an intercontinental super grid on the electricity system (Paper IV)

Motivation and research question

The sun never sets from a global perspective, and half of the earth is bathed in sunshine at any given time. An idea to utilize the never-set solar radiation is to build an intercontinental transmission network to connect different time zones and trade renewable energy across borders. Following this idea, the Prime Ministers of India and the UK jointly released the One Sun One World One Grid (OSOWOG) initiative at the COP26 Climate Meet in Glasgow. Its objective is to aid in developing a super grid covering the entire world to transmit clean energy globally at any time. In this study, *we evaluate the impact of an intercontinental super grid as suggested by OSOWOG on the cost and configuration of the future renewable energy system while considering the heterogeneity of cost of capital between countries*.

Methods

We use a techno-economic cost optimization model with hourly time resolution to model six interconnected sunny regions: Australia (AU), South Asia (SA), Middle East and North Africa (MENA), Central and South Europe (CSE), South America (SA), Central and North America (CAN). The six regions include all the member countries of the OSOWOG initiative, and each region is divided into several subregions. In total, this study covers 48 subregions spanning 18 time zones. The system cost for a renewable energy system in 2050 is assessed based on three different levels of transmission connection: 1) *Isolation* – the subregions inside each region are isolated from each other without transmission connection; 2) *Regional grid* – intracontinental transmission expansion is allowed within each region; 3) *Super grid* – intercontinental super grid expansion is allowed to connect the six regions. The cost benefit of the intercontinental super grid is then evaluated under different assumptions for technology costs, discount rate, availability of nuclear power and uncertainty of future electricity demand.

Main findings

Expanding transmission grids inside each region consistently reduces the average electricity system cost (see Fig. 19). The average cost reduction due to regional grid expansion is 14%. In stark contrast, the cost benefit of the super grid, i.e., connecting different continents, is a mere 2.6%. The results indicate that the economic benefit of a global super grid as suggested by OSOWOG is likely rather limited.

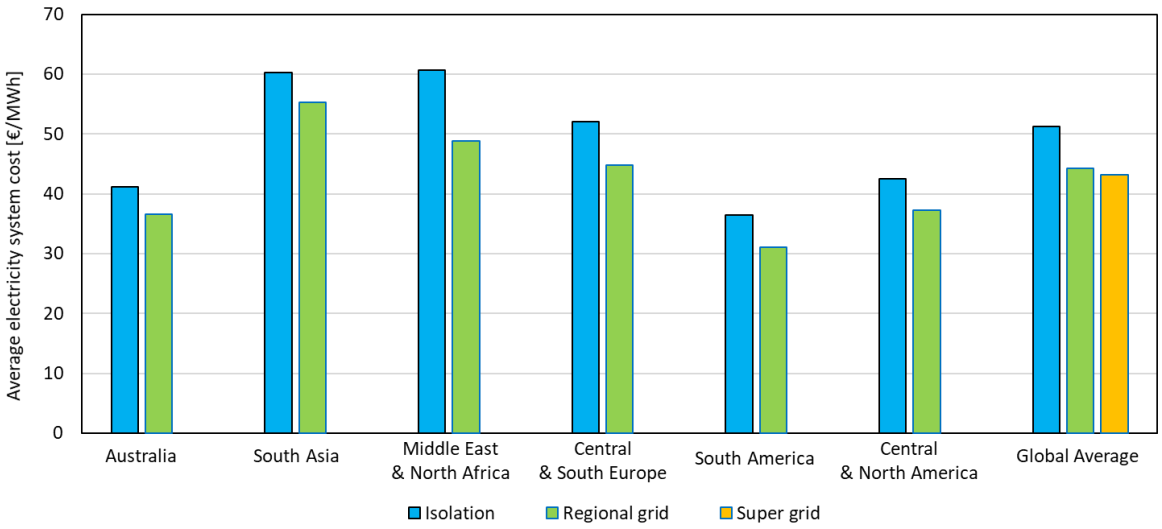

Fig. 19. Average electricity system cost based on three different levels of transmission connection: *Isolation*, *Regional grid* and *Super grid*.

The OSOWOG initiative suggests developing an intercontinental super grid to advance the deployment of solar PV. To test this hypothesis, we investigate the optimal electricity supply mix under various cost assumptions for solar and storage. Our results show the opposite that allowing for a super grid makes solar PV less cost-effective (see Fig. 20). Allowing for intercontinental transmission expansion, and thus connecting time zones, consistently increases the share of wind in the optimal electricity supply mix compared to regional grid integration. As a consequence of the increased deployment of wind power, the share of solar PV and battery storage in the optimal electricity supply mix decreases. The decrease of battery storage is not surprising, as battery is primarily a short-term storage technology to complement the diurnal variation of solar PV [2, 3]. Our results confirm that, compared with storage, transmission and trade are less cost-effective to balance the natural diurnal variation of solar.

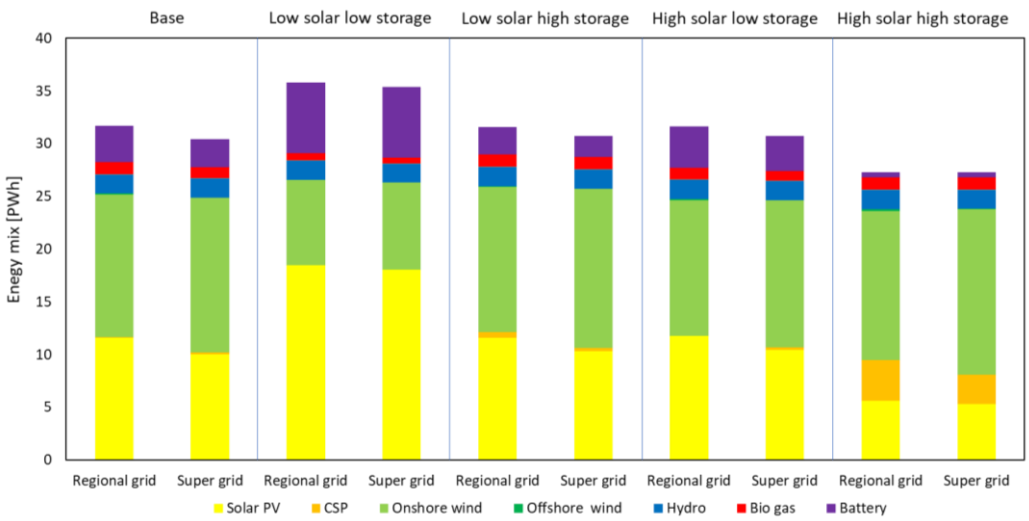

Fig. 20. Electricity supply mix under different cost assumptions for solar and battery storage.

Conclusions

We use a detailed techno-economic cost optimization model to evaluate the cost benefit of a super grid as suggested by the OSOWOG initiative. The results show that a global super grid decreases the electricity system cost by 0-5%. Compared with the limited cost benefit of an inter-continental super grid, expanding transmission grids within each region leads to a greater cost reduction (14%). The marginal benefit of further connecting different regions decreases significantly. Integrating different continents always has a negative impact on the expansion of solar PV, though eighteen time zones are covered for the analysis. A global super grid as suggested by OSOWOG, does not benefit the deployment of solar PV.

Impacts on the electricity system of excluding nuclear power for Sweden (Paper V)

Motivation and research question

Nuclear power accounts for 31% of the annual electricity production in Sweden [43], but the nuclear fleet is aging, and decommissioning is planned in the coming decades for economic reasons. Currently, there is an ongoing debate in Sweden as to whether new nuclear power plants should be installed after the decommissioning of existing ones. A key issue surrounding the debate is whether the electricity system cost will escalate if nuclear power is excluded from the future Swedish electricity system. Therefore, we develop a techno-economic cost optimization model (REX) with a high temporal resolution for the Swedish and European electricity systems, to investigate the cost of the future low-carbon electricity system without nuclear power for Sweden. The following research questions are addressed.

1) What is the cost of a future low-carbon electricity system without nuclear power for Sweden, given the present interconnecting transmission capacities within Sweden and between Sweden and neighboring countries?

2) How is the cost affected if additional investments in transmission within Sweden and to other countries are allowed?

Methods

We use the REX model to investigate the future interconnected European electricity system for year 2045 with an hourly time resolution, assuming a CO_2 emissions constraint of 10 g/kWh of the electricity demand. The economic performance of the Swedish electricity system with and without nuclear power is evaluated based on the nodal net average system cost (NNASC).

The European electricity system covers a large geographic area with different VRE resource endowments for different locations. Using a techno-economic cost optimization model to investigate such a system may result in concentrating investments in renewable generation capacity to a few sites with the best harvests. Countries may then satisfy their domestic demands through importing electricity from neighboring countries with better outputs and paying for the imported electricity. The conventional system cost concept based on generation and transmission costs cannot represent the electricity system cost for an individual country, as the effect of trade is not considered. This problem can be solved by isolating a country and not allowing trade in electricity. However, this may generate misleading results, as electricity trade is important for electricity supply and variation management within a low-carbon electricity system with a high penetration of VRE [2, 3, 23]. To represent the system cost for an individual country in the interconnected European electricity system, we introduced the nodal net average system cost (NNASC) to incorporate trade profit and congestion rent [1], in addition to generation and transmission costs.

Main findings

The availability of nuclear power has limited impacts on the NNASC for Sweden in a future decarbonized European electricity system. The reduction in NNASC for Sweden due to the availability of nuclear power is less than 4.2%, and this holds true regardless of whether or not there is expansion of transmission capacity (Fix and Exp cases in Fig. 21a). As is evident in Fig. 21b, Sweden is a net importer in the current transmission case (case Fix), whereas when transmission is expanded optimally (case Exp) Sweden becomes a net exporter. In the optimal transmission cases (case Exp), Sweden receives high revenues from electricity exports. The main reason for this is that Sweden has a large volume of reservoir hydropower, which enables exportation when the supply of renewable power in Europe is scarce. When nuclear power is available (NUC-Exp), this effect is further enhanced, with higher net exports than in the case without nuclear power (NoNUC-Exp).

[1] *Congestion rent* is defined as the price difference times the power flow over a transmission network constraint.

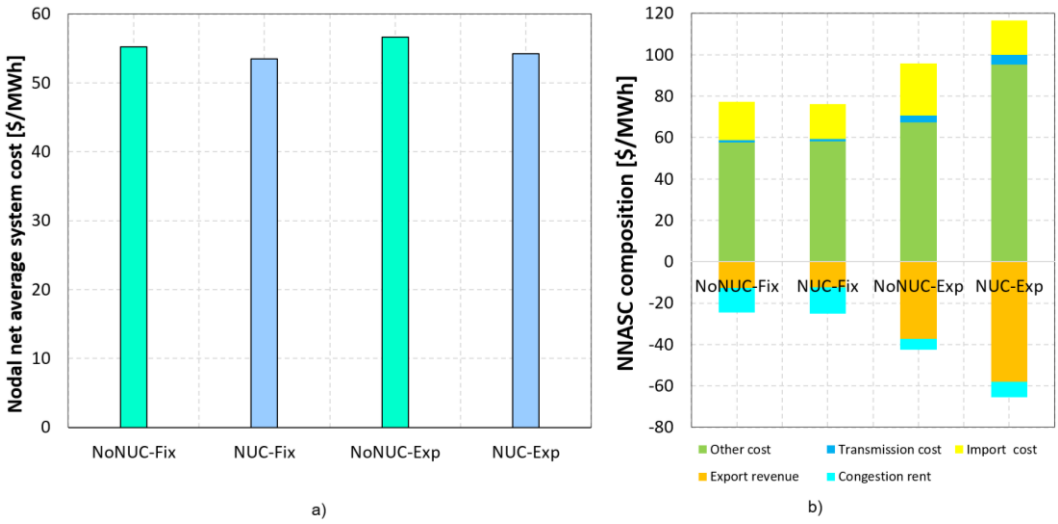

Fig. 21. Results for system cost from the modeling of the base scenarios. a) Nodal net average system cost for Sweden. b) Nodal net average system cost composition for Sweden. Since the costs of storage and demand-response are very low for Sweden, the 'Other cost' in (b) refers mainly to generation-related costs.

We further conduct sensitivity analyses to uncover how nuclear power, storage and transmission costs affect the difference in NNASC for a system in Sweden with nuclear power relative to a system without nuclear power. With the present transmission capacity, the maximum economic benefit of nuclear power for Sweden is 10.2% (Fig. 22a). For the cases of optimal transmission, the cost differences between the nuclear power and non-nuclear power scenarios are in the range of 0% –16.5% (Fig. 22b). Unsurprisingly, the upper range of the cost reductions is obtained when the cost of nuclear power is low. Notably, the low investment cost for nuclear power, 3500 $/kW, is less than two-thirds of the projected value for Europe today [156]. Furthermore, the benefit of investing in nuclear power increases with higher storage costs, as more costly storage increases the cost of a highly renewable electricity system. However, investments in nuclear power in Sweden enable higher levels of electricity export from Sweden to smoothen the variations in the European electricity system and reduce the system-wide cost.

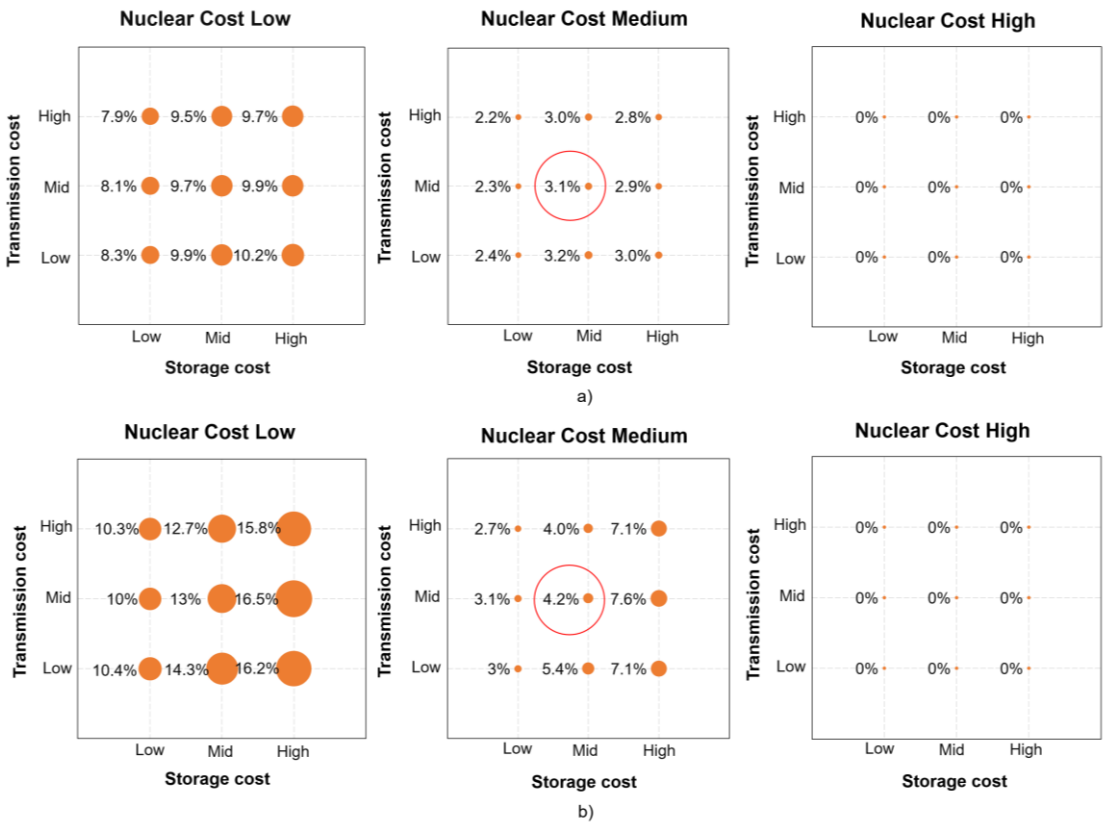

Fig. 22. The decrease in NNASC for Sweden with nuclear power compared to the case without nuclear power, using various assumptions related to the investment costs for nuclear power, storage and transmission. a) Cost difference between cases NUC-Fix and NoNUC-Fix. b) Cost difference between cases NUC-Exp and NoNUC-Exp. The results for the base scenarios are marked with red circles.

Conclusions

In this study, we model the European electricity system and analyze the nodal net average electricity system cost for Sweden. Our results show that:

- The economic rationale for Sweden as a country to invest in nuclear power if there is a transition towards a low-carbon electricity system in Europe is weak;
- The case with the best economic prospects for investment in nuclear power in Sweden is when the transmission capacity is optimal, in combination with a low cost for nuclear power and a high cost for storage. In this case, the inclusion of nuclear power reduces the NNASC for Sweden by 16.5%;
- In a highly renewable electricity system, allowing additional investment in transmission capacity would benefit Sweden through increased profits from electricity trading.

Reflection on methods and limitations of the thesis

Energy system model settings for this thesis regarding the six important aspects

In the beginning of the **Methodology** chapter, the energy system models are characterized along six important aspects, i.e., temporal resolution, spatial resolution, spatial scope, sectors included, pathway and discount rate. For studies in this thesis, we use *Greenfield* techno-economic cost optimization models to investigate the investments for future low-carbon electricity systems. Instead of looking at the transitioning pathway or the system evolution, we focus on the static end-state of the future systems. The *Pathway* approach introduces additional complexity and requires additional computation power and time commitment. The question concerning the selection of methodology (*Pathway* or *Greenfield*) for this thesis is whether the additional effort required by the *Pathway* approach justifies the benefits it provides for addressing the research questions and whether the *Pathway* approach is influential to our primary conclusions. For **Paper I**, the research focus is the impact of a changed demand pattern on electricity system cost and electricity supply mix. If a *Pathway* approach is applied, one might find that the demand pattern is not consequential to system cost when large scale fossil fuel-fired power plants are still in commission as they are capable of load following. When most of the fossil power plants are phased out, one may observe similar results as we show in **Paper I**. Nevertheless, the main information learnt from the *Pathway* approach can be achieved with the *Greenfield* approach with various carbon caps. For **Paper II**, our primary focus is how the change in electricity demand due to electric cooling might affect the cost-optimal investment in solar PV. A transition *Pathway* approach starting from the current status of the electricity system might give more information about how the system configuration changes and the corresponding investment strategies along the growth of cooling demand over time. Ideally, such analysis might give more direct information regarding when it is cost-optimal to invest in solar PV to power cooling? Is it 2030 or 2050? However, we do see the difficulty in capturing the dynamics of important factors, that affect the optimal investment strategies, such as change in climate policies and technology innovations along the transition pathway. So instead of devoting the effort to capture the dynamics in system evolution associated with increased cooling demand for a specific region, we prioritize the analysis of more geographic areas across the world to gain more generic information about the impact of increased cooling demand on the cost-optimal investment in solar PV. Still, we analyze the investment strategies under different assumptions for carbon cap. Our results generate similar insights regarding whether solar PV is cost-optimal for a renewable energy system or a system where a lot of fossil power plants are still in commission. For **Paper V**, we investigate the potential role of nuclear power for the Swedish electricity system. The current nuclear power investment cost is high and the construction time is very long in Europe, while wind and solar are relatively cheap and fast to install. If the transition pathway approach is applied, one might

observe that nuclear power is not cost-effective for now and in the future. Or even if so, it might only have a minor impact on system cost as is shown in Fattahi et al. [157]. Since our main research focus is the impact of nuclear on Swedish electricity system cost, a pathway analysis is not likely to change our main conclusion for **Paper V**. An interesting point worth mentioning is that the Finish government canceled the plan of the sixth nuclear reactor due to the repeated delays and substantially escalated cost for the fifth reactor. The technology learning for nuclear power stopped. But in a pathway model, the cost assumption of nuclear power typically decreases over time to account for learning by doing and economy of scale. This example vividly shows the challenges in capturing the technological dynamics in pathway models.

Given the importance of temporal resolution, we use an hourly temporal resolution to represent the variability in generation of VRE for all the studies, which is the core of this thesis. As for spatial resolution, the smallest subregion included in this thesis is the electricity bidding zone in Sweden. Such a setup can capture the regional diversity of hydropower resources and represent the transmission bottleneck between north and south of Sweden. The VRE resources in each subregion are aggregated to five different classes based on resource quality. This method better captures regional difference in VRE resource quality as compared with aggregating regional VRE resource to an average capacity factor. As for transmission grid, the subregions are assumed to be connected with high-voltage direct current (HVDC) transmission grids and the electricity trade is represented as a simple transport problem [3, 4]. All the subregions are treated as "copper plates" without intra-regional transmission constraints. Thus, this thesis does not capture the grid bottlenecks inside each subregion. The bottlenecks of intra-regional transmission networks may limit the amount of cross-border electricity trade. As a result, more domestic generation capacity might be installed, which would drive up the cost for the regional electricity system. In addition, the transmission networks inside each subregion are not well represented, this setup might lead to an underestimation of the transmission (and distribution) cost. Overall, there might be an underestimation of the regional electricity system cost in this thesis, given that the transmission constraints inside each subregion are not considered. In **Paper IV**, we investigate the impact of an intercontinental super grid on the electricity system cost. Representing the grid bottlenecks inside each subregion might lower the cost benefit of a super grid, as transmission constraints at the subregion level might limit the capability of a super grid to tap remote high-quality resources. But since we investigate the case that transmission capacity can be liberally expanded, such an effect might be rather limited [114]. Similar reasoning applies for **Paper V**, for the case with current transmission capacity, the transmission bottleneck inside the subregion might limit the export of hydropower from the north to the south, which might favor the investment in nuclear power for the south of Sweden. For the case of optimal transmission expansion, the impact of subregional transmission bottleneck might be insignificant. In summary, we prioritize the

temporal resolution to represent accurately the variability of VRE generation. As a trade-off, the spatial resolution is relatively coarse. In future studies, we hope to investigate further the spatial granularity (size of subregion) given the research aim.

As for spatial scope, for **Paper II**, we investigate seven sunny regions with potentially large demand for electric cooling. Some of the investigated regions are part of big countries. We exclude the rest of these countries purposely to reveal better the impact of electric cooling on the cost-optimal investment in solar PV. If we instead investigate the entire country, the impact of electric cooling on the electricity supply mix might be affected by the trading with the neighboring countries. Less or more domestic generation capacity might be installed due to electricity import or export. In **Paper IV**, we explore the impact of an intercontinental super grid on the renewable electricity system cost and configuration. We intentionally evaluate the potential benefit of extending spatial scope beyond continental level. For **Paper V**, our focus is the Swedish electricity system, still we expand the system boundary to Europe to acquire a decent representation of cross-border electricity trade. To conclude, we carefully choose the system boundary based on our research questions.

As for sector-coupling, we do not explicitly include the other energy sectors in our analysis, though we do investigate scenarios that entail an increased electricity demand, possibly due to sector coupling for **Papers III**, **IV** and **V**. For **Paper IV**, a higher demand increases the economic benefit of a super grid, although the overall effect is limited. In **Paper V**, a higher electricity demand promotes the economic prospect for nuclear power investment in Sweden. The fact that we do not consider sectoring coupling in the model might neglect the potential flexibilities provided by the other energy sectors. The availability of large-scale flexibilities offered by the other energy sectors reduces the economic benefits for nuclear power and super grid [5]. For **Paper I**, we investigate the change in demand pattern and the corresponding impacts on the modeling output, while the volume of demand is kept the same. If the volume of the electricity demand is dramatically increased due to sector coupling, the impacts of different demand patterns on the modeling results may be heavily influenced by the scarcity of VRE supply due to land availability constraints.

Both wind and solar projects require significant amounts of land, especially utility-scale installations. The availability of suitable land for wind and solar energy is an important factor to consider in the planning of large-scale low-carbon electricity systems, due to rising competition for land and environmental concerns. Some studies have shown that reducing the amount of available land for wind and solar power production could significantly increase electricity system costs [4, 158, 159]. Fälth et al. [159] revealed that reducing the amount of available land for wind and solar from 10% to 2% could increase electricity system costs by 50% for Middle East and

North Africa and 25% for Europe. Schlachtberger et al. [4] found that eliminating land availability for onshore wind power in Europe could lead to a 10% increase in electricity system cost. Similarly, Bolwig et al. [158] concluded that low social acceptance for wind power could result in a 12% increase in electricity cost for the Nordic-Baltic region. The limited availability of land means that the most productive sites for wind and solar energy are already in use, which results in the need to exploit less productive sites with lower capacity factors. This can significantly increase the system cost for wind and solar energy deployment.

As for discount rate, we assume uniform discount rate for **Papers I**, **II** and **V**. In **Paper I**, we investigate the change in demand pattern on the overall modeling output for a stylized case and Europe in a renewable future. Applying country-specific discount rate might change the specific system cost and electricity supply mix, yet it is not likely to affect the main message we want to deliver, that is the magnitude of error of using historical demand profiles as input to the model. Similar reasoning applies for **Paper II**, especially for the low carbon scenarios, as a higher or lower discount rate affects VRE technologies homogeneously. Yet we do see that a higher discount rate might favors more fossil fuel-fired power plants for scenarios with more generous carbon caps. As a consequence, the share of solar PV might decrease. For **Paper V**, the regional difference in discount rate might affect the regional capacity mix and the trade pattern between Sweden and neighboring countries, which might affect the potential role of nuclear power for Sweden. In addition, discount rate differs between technologies [90]. We hope to further investigate the impact of technology-specific discount rate on the role of nuclear power in the future low-carbon Swedish electricity system. For **Papers III** and **IV**, we analyze the VRE costs for different countries and the potential trade between countries. Country-specific discount rate based on present value is applied to account for the regional difference in investment risks. In addition, a unform discount rate is applied in **Papers III** and **IV** for results comparison. We do see that using present data to represent future discount rates can be problematic. The future discount rate is uncertain and subject to change, particularly in a rapidly changing economic or political environment. Countries that are unstable today may become stable in the future, while countries that has a low-risk premium today, may fall into socio-political unrest. Therefore, we are agnostic to the exact value of future discount rate for each country.

Other limitations and reflections

One limitation of this thesis is that there are no operational constraints for thermal generation technologies, such as ramping rates for nuclear power. The ramping rate influences the speed with which a nuclear power plant responds to the load change in the power grid [56]. The lack of thermal constraints is likely to lead to an overestimation of the flexibility provided by thermal power. In addition, we simplify the modeling of hydropower plants in each subregion by

aggregating them into a single plant. This approach neglects important factors that can affect the operation of hydropower, including cascade effects, head dependency, and turbine efficiency functions [160]. Accounting for these constraints would result in lower flexibility provided by hydropower than what is modeled. Therefore, the technical detail for this thesis is relatively coarse, which overestimates the flexibilities provided by conventional thermal and hydropower plants. As a result, this thesis might have an underestimation of required investment in wind and solar and the corresponding system cost. As for the impact on the main conclusion for each study, for **Paper I**, this might underestimate the impact of a changed demand pattern on system cost as more flexibilities make it easier to follow the change in demand pattern. For **Paper II**, more wind, thermal power plants and battery storage might be needed to balance the demand at night when there is no output from the sun. For **Paper IV**, a super grid shares both VRE and dispatchable resources. A more detailed technical constraint entails that less flexibility is available for sharing, which might reduce the potential benefit of a super grid. For **Paper V**, with less flexibilities from hydropower, the investment in nuclear power might be more attractive.

Another limitation relates to uncertainties linked to the weather data for wind and solar power generation. For a low-carbon electricity system with a high share of VRE, the electricity generation depends strongly on the weather conditions. The weather data might be different for different years. For **Papers I** and **II**, multiple weather years are used. The results show that varying the weather year as input to the model has a minor impact on the main outcomes. For **Papers III**, **IV** and **V**, the data for wind and solar power are based on a single year. For **Paper III**, a different weather year might influence the calculated potential of wind and solar for a specific country. We expect further analysis to understand to what extend this might affect our main conclusions. As for super grid analysis, Reichenberg et al. [120] used multiple weather years as input to investigate the cost benefit of an Eurasia super grid and showed no significant difference regarding the effect on cost of the super grid option. The interannual variability of weather condition might be smoothed out over a large geographic area. Therefore, a different weather year might have a minor impact on our conclusion about the benefit of a global super grid. As for **Paper V**, a different weather year, especially extreme weather conditions such as long-term 'dunkelflaute' periods with low generation from wind and solar plus dry weather year with low output from hydropower, are situations that might favor the investment in nuclear power. However, extreme weather events such as heat wave and the subsequent dry period might also affect the reliability of nuclear power by reducing operation efficiency and cooling water supply for nuclear power. We expect further systematic analyses to understand how the extreme weather conditions might affect the role of nuclear power in a future low-carbon electricity system.

In this thesis, we focus on the optimization of an electricity system that covers a large geographic area, whereby the VRE and dispatchable resources are shared and the variations are smoothed

over the continental transmission network. A potential consequence of this approach is that the generation capacity is concentrated to several sites with the best VRE resource potentials. On the one hand, countries with good VRE resources might install large generation capacities and create job opportunities and revenues for the local community, while absorbing the land use and environmental impacts. On the other hand, countries with less resources might rely more on imports for the electricity supply and pay for the traded electricity but face potential energy security problems. The uneven deployment of renewable generation capacity in different countries may result in an uneven distribution of the associated regional impacts, which may lead to social acceptance problems [161]. One way to address this issue is to model the continental electricity system and incorporate self-sufficiency for individual countries. Tröndle et al. [6], for example, developed an optimization scheme for the European electricity system that ensures each country's annual electricity demand is met by its own domestic electricity production, while also enabling cross-border trading to balance hourly electricity demand across the continent.

This thesis focuses solely on techno-economic analysis and does not fully consider the social and political challenges associated with key low-carbon energy technologies. To represent social acceptance for wind and solar power, we assume a uniform fraction of available land for their installation across all regions. However, the social acceptance of wind and solar varies from region to region. Installing large-scale VRE projects in densely populated areas can be more challenging compared to remote areas like deserts and offshore locations. One possible way to measure the variation in social acceptance across regions is to incorporate social acceptance costs e.g., the compensation to the population groups affected by the deployment of a VRE project, into the cost structure for VRE, leading to a more realistic representation of wind and solar costs when compared to assuming uniform costs everywhere [162]. However, it can be challenging to quantify social acceptance costs in monetary terms. A more realistic representation of social acceptance of wind and solar than what is done in this thesis, might affect the regional capacity mix and system cost. We expect future studies to investigate how social acceptance influences the placement of various energy infrastructures and the resulting effects on system configuration and costs. A systematic exploration of this topic would provide valuable insights for policymakers, energy stakeholders and researchers. This thesis also explores extreme scenarios involving transmission and nuclear power. These scenarios, with or without transmission or nuclear, depict system designs that represent the outer bounds of social acceptance towards nuclear power and transmission expansion. The outcomes of these scenarios, along with various potential solutions in between, delineate the feasibility space for designing a low-carbon electricity system in the future, accounting for different levels of social acceptance towards nuclear power and transmission grids.

Reflection on results

Over the course of the author's PhD research, there have been significant progresses in the field of energy system modeling regarding spatial resolution [114], spatial scope [6, 163], sector-coupling [5], heterogeneous discount rate [134], flexibility requirement [42], land availability and deployment density [146], feasibility space [164], uncertainty in weather condition [165] and more. This thesis mainly contributes to a better understanding of demand pattern, spatial scope, role of nuclear power and alternative solutions.

Demand pattern

The first part (**Papers I** and **II)** of this thesis focuses on the change of future electricity demand pattern. It is well established that future electricity demand patterns are subject to significant uncertainties [12-21]. This thesis contributes to a better understanding of how these uncertainties may affect electricity system cost and electricity supply mix for Europe (**Paper I**). Many studies have investigated the potential impact of EV charging on the diurnal demand pattern and the corresponding effects on the electricity system [7, 166-169]. Taljegard et al. [166], Carrión et al. [167] and Gunkel et al. [168] evaluated the impact of different EV charging strategies on system cost and have reported that the changes in diurnal demand pattern due to different charging strategies have a rather limited impact on the system cost (<3%). Similarly, Zappa et al. [7] assumed different diurnal variations in the demand profile and showed that changes in the diurnal demand pattern have a negligible impact on the system cost. This thesis conducts a systematic investigation of various diurnal demand patterns, including zero, medium, and high diurnal demand patterns, and further confirms that altered diurnal demand patterns have a minor impact on system cost (<3%). However, we did not explore the case in which there is an extremely high peak demand, e.g., charging all the EVs together immediately after work. In the case of an extremely high evening peak when there is no output from solar PV, the system cost might escalate.

As for seasonal demand pattern, Zeyen et al. [170] explicitly investigated the impact of changed seasonal demand pattern on the electricity system cost and electricity supply mix for Europe and found that for a sector-coupled energy system, a high winter peak due to large-scale electric heating increases the system cost by up to 30% compared to a flat heat demand without seasonal variation. In contrast, this thesis suggests that a high winter peak has a negligible impact on system cost compared to a demand profile without seasonal variation. The discrepancy between our result and that of Zeyen et al. may be due to the significantly higher winter peak investigated by Zeyen et al., as both the seasonal variation and the volume of electricity demand is much larger than that of our study. The scarcity of suitable land for deploying VRE can substantially increase system cost for a renewable energy system, particularly when there is high electricity demand and limited

land availability [120]. This is mainly because a higher overall demand may lead to full utilization of renewable sites with high load factors, forcing the exploitation of poorer sites. We test our hypothesis by doubling the electricity demand for Europe in **Paper I**, and the results show that a high winter peak could increase the system cost by 7% compared to a flat demand profile with no seasonal variation, supporting our hypothesis that the volume of demand or land availability significantly impact system cost. This is also confirmed by **Paper III**, where large cost escalation is observed for some countries when electricity demand is doubled, and some European countries cannot even cover their electricity demand with domestic renewable resources in such a situation. Based on the analysis above, it appears that the impact of demand pattern change on system cost is strongly influenced by the volume of demand or land availability.

Regarding the impact of summer peak, a study conducted by Zhu et al. [171] examined the impact of global temperature rise on the cost-optimal design of the European energy system and found that a higher summer demand has a negligible effect on electricity system cost. However, our study discovered a much greater impact of summer peak on system cost (8%), possibly due to the much larger amplitude of the summer peak in our electricity demand profile. Zhu et al. explored a case with a limited increase in cooling demand and a large decrease in heating demand due to the global temperature increase. As a consequence, the results in Zhu et al. represent a combined effect of increased cooling and decreased heating.

In **Paper II**, we also investigate the impact of a higher summer peak due to residential electric cooling on the average electricity system cost for seven regions in the tropical and subtropical zones. Surprisingly, the results show that a higher summer peak due to increased cooling either decreases or has small effects on the average electricity system cost, which seems to contradict the findings of **Paper I**. In **Paper I**, the comparison base is the current demand pattern for Europe, which features a typical winter peak, while in **Paper II**, the comparison base is a typical summer peak demand profile that includes cooling demand from non-residential sectors, such as commercial buildings. To ensure a comparable basis for comparison, we calculate the difference in the average electricity system cost between a medium summer peak and a high summer peak for **Paper I**, which yields a minor difference in average system cost (2%). Therefore, the findings of **Paper I** and **Paper II** are consistent with each other. In **Paper II** the increase in cooling demand results in a higher summer peak and a shift in the diurnal demand pattern, with more demand during daytime hours when solar PV output is high. The improved alignment between electricity demand and solar PV output due to increased cooling leads to a higher utilization rate of solar PV, resulting in lower average system costs for some regions.

Overall, our results show that the electricity supply mix is more sensitive to demand pattern than the system cost, which is confirmed by Refs. [166, 170]. Specifically, this thesis shows that a

higher diurnal variation due to increased cooling demand leads to more solar PV in the optimal electricity supply mix, which is the core of **Paper II**. Similarly, Zhu et al. [171] explicitly explored the increase in cooling demand and found that a higher cooling demand integrates more solar PV for South Europe. This phenomenon is also observed by some other studies [166, 169], where the authors found that smart charging can shift electricity demand to the day time with high output from solar PV, resulting in an optimal capacity mix that includes more solar PV. Though Taljegard et al. [166] and Manríquez [169] did not analyze the impact of cooling, the overall effect of smart charging on electricity demand profile is similar to the impact of increased cooling demand. As such, both electric cooling and smart charging of electric vehicles could enhance the synergy between electricity demand and solar PV production, promoting the deployment of solar PV for a renewable energy system.

To summarize, in **Paper I** we aim to examine whether directly using historical electricity demand profile as input to capacity expansion models (CEMs) could result in misleading conclusions regarding electricity system cost and the electricity supply mix. The results of this study provide practical information to the energy system modeling community about the magnitude of error in modeling results of neglecting the change in future electricity demand pattern in modeling practice, e.g., the planning of future renewable energy systems. In most cases, if the total electricity consumption remains stable, using historical electricity demand profile as input is generally not likely to have a significant impact on system cost. However, if a modeler expects a future demand profile with a high summer peak, or intends to analyze the electricity supply mix, it is essential to be cautious in making assumptions about the future electricity demand pattern.

Since the impact of demand pattern change on system cost is strongly influenced by the volume of demand or land availability, we realize our conclusion may not hold true for modeling practices that involve large-scale sector coupling, as demonstrated by Zeyen et al. [170]. When modeling a renewable energy system, the scarcity of land for the deployment of VRE has a similar impact on system cost as high demand. With the growing opposition towards wind and solar projects, the shortage of suitable land for VRE deployment is becoming increasingly likely [172]. This issue is particularly pressing for countries with high population densities, as they may struggle to find adequate space for VRE projects compared to countries with lower population densities. Therefore, it is crucial for modelers and policymakers to consider social constraints to the exploitation of VRE resources and the trade-off between system cost and land availability in their planning efforts.

As for using solar energy to power electric cooling, Laine et al. [173] assumed that the entire future cooling demand will be satisfied with electricity generated by solar PV given the apparent synergy between cooling demand and solar irradiation. With similar reasoning, Alghamdi [174]

estimated that electricity generated by solar rooftop can power up to 80% of the household electricity demand in Saudi Arabia. Likewise, Shi et al. [175] found that solar rooftop plus storage may contribute to 20.8% of the electricity demand for Beijing, China given the correlation between solar power production and cooling demand and the optimal charging for EVs. The IEA report [176] optimized the electricity system as we do and showed that not only solar PV, but also wind power and a large share of fossil fuel-fired power plants are installed to meet the cooling demand. Zhu et al. [171] investigated the electricity system for Europe and found that a higher cooling demand favors more solar PV (than wind) in southern Europe. Our results from **Paper II** further show that it is cost-optimal to invest in solar PV to power the electric cooling for seven different regions across the world. The IEA report [176] has more fossil fuel fired power plants installed compared with Zhu et al. [171] and our results possibly due to that a more generous carbon cap is applied. The results of **Paper II** are especially relevant for developing countries in the tropical zones. With these countries becoming wealthier and the expected temperature rise due to climate change, electric cooling will likely become more prevalent to maintain comfortable indoor temperatures. Our results show that solar PV can serve as a cost-effective solution for meeting the growing demand for cooling, not only for a fully renewable electricity system, but also for a semi-renewable system that includes fossil fuel-based power plants. This implies that it is cost-optimal to expanding solar PV generation alongside the increased use of electric cooling. Given that many of these countries rely heavily on fossil fuels for electricity generation, utilizing solar PV to power electric cooling could expedite the decarbonization of their electricity systems.

Spatial scope

One major contribution of this thesis relates to spatial scope (**Paper IV** and **V**). Increasing the spatial scope of an electricity system allows for a larger geographic area to share both VRE and dispatchable resources, which has been shown in previous modeling studies to be a cost-effective strategy for a renewable electricity system [3, 22, 39, 159]. These studies showed that integrating different countries/regions at the continental level through transmission grids can reduce electricity system costs by up to 30% for Europe [3], 10% for North America [39], 15% for Northeast Asia [22, 39] and 25% for MENA [159], compared to modeling the regions in isolation. Tröndle et al. [6] took this analysis further by distinguishing between energy supply and energy balance, finding that a system with national supply and continental balancing can result in a 24% cheaper cost than isolated national systems.

This thesis investigates the potential spatial scope of a VRE dominated electricity system across three distinct levels: 1) an isolated region, 2) continental level with intracontinental grid connections, and 3) global level with intercontinental grid connections. By systematically comparing the cost of electricity systems across these different spatial scopes, the thesis evaluates

the benefits of extending spatial scope through expanded transmission grids (**Paper IV**). Our results show that intracontinental grid expansion may reduce the average electricity system cost by 14% on average, which is consistent with Refs. [3, 22, 39, 159]. On top of this, we extend the spatial scope to the global level as suggested by the OSOWOG initiative. The results show that integrating different continents reduces the electricity system cost by 2.6%, which is in the same range as the findings of other intercontinental studies [120-123]. The economic benefit of a global super grid is rather limited compared with grid integration at the continental level, which indicates that the benefit of extending spatial scope for resource sharing is primarily achieved at the continental level given the large geographical area coved. The marginal benefit of further integrating different continents decreases significantly. To better account for regional variations in investment risks and the potential effects on cross-border electricity trade, country-specific discount rate is applied for **Paper IV**. The findings show that considering the heterogeneity in discount rates reduces the benefit of extending spatial scope via transmission grids to the global level, assuming that the current pattern of inequality in investment risks persists.

From a global perspective, the sun is always shining somewhere. Some studies suggest that trading solar energy across different time zones could help to mitigate the diurnal variation of solar power production [177-179]. However, previous intercontinental studies based on CEMs showed that integrating different continents always has a negative impact on the expansion of solar PV [120-123]. In this thesis we find that even under a very favorable condition (low cost for solar and extremely high cost for domestic storage), integrating different continents does not facilitate the deployment of solar PV. Therefore, this thesis further confirms that transmission and trade is not a cost-effective strategy for addressing the natural diurnal variation of solar power production, even when multiple time zones are interconnected. Given the rather limited cost benefit and the non-detectable impact on solar deployment of integrating different continents, the potential benefit of a global super grid as suggested by the OSOWOG initiative is questionable.

One of the challenges associated with a broad spatial scope is modeling trade for individual countries within an interconnected continental electricity system, as modeling efforts often focus on individual countries rather than the entire continent. The benefits of trade in sharing recourse and spatial smoothing the intermittency of VRE, thus reducing electricity system cost, have already been highlighted by this thesis and many other studies discussed above. Traditionally, many studies have only considered the geographic scope of the focal country without accounting for cross-border trade [46, 180, 181]. A second common approach is to use exogenously defined import/export price-quantity pairs to represent cross-border trade [44, 45, 157]. The third method involves expanding the model scope to encompass a broader region than the focal country/region and endogenizing the dispatch decisions in all neighboring countries [119, 182]. The first two methods are advantageous in reducing computational efforts, but they have drawbacks. Method

one ignores the benefits of cross-border trade entirely, while method two's accuracy depends on the design of the cross-border trade function. Oversimplifying the trade function, e.g., following historical trade patterns [44], aggregating historical import as a storage [45] and using annual average cross-border trade curves [163], lead to a significant loss of accuracy. Furthermore, this method fails to account for the bilateral power flows that occur between neighboring countries. Consequently, the potential benefits of geography are not fully realized, as neighboring countries are unable to serve as transit countries. Method three, on the other hand, is suggested by Mertens et al. [163] to be the most accurate method to represent cross-border trade because dispatch in neighboring countries is optimized at the same time as the focused country. This method is used in this thesis. In **Paper V**, the focus is on Sweden, and the system boundary is extended to Europe. The entire European electricity system is then optimized to have a reasonable representation of cross-border trade.

We do encounter another challenge regarding how to measure the system cost for a country in an interconnected electricity system given that the installed generation infrastructures are shared with other countries. Tranberg et al. [183] proposed a method for assigning the capital and operational costs associated with imported electricity from external generation capacities to the importing countries by tracing the power flow. Pattupara and Kannan [119] included electricity trade revenue in the system cost and evaluated its impact on the national electricity system cost. Tranberg et al. [183] only focused on the cost without considering the benefits from electricity trade. Pattupara and Kannan [119] took the trade revenue into account, but neglected the congestion rent. The thesis presents a new metric, called the nodal net average system cost (NNASC), for quantifying the net system cost of a country or region in an interconnected electricity system. The NNASC incorporates the system-wide capital and operational costs of generation and transmission, as well as the profit of trade (export revenue minus import cost) and congestion rent. By capturing both the cost and revenue associated with trade, the NNASC provides a comprehensive approach to measuring the overall impact of cross-border electricity trade on a specific country or region. Price et al. [184] have utilized this metric to measure the net system cost for the UK. In addition, the NNASC captures the key components for social welfare calculation. The change of NNASC after transmission expansion can be used as an indicator to measure the welfare gain from transmission expansion for each country. Mertens et al. [163] used a similar method to evaluate the welfare gain from trading with the neighboring countries for Belgium. The chief difference between what we suggested above and the method of Mertens et al. [163] is that they distributed the congestion rent equally between the two neighboring countries, while in our study the exporter receives all the congestion rent resulting from electricity export.

Many studies proposed utilizing North Africa's abundant high-quality solar resources to produce solar energy or green hydrogen for Europe [179, 185-188]. However, our findings indicate that

the application of a country-specific discount rate results in a significant reduction in investments in renewable energy for Africa. This observation is consistent with Ameli et al. [131], who found that the use of country-specific discount rates leads to a 35% decrease in renewable electricity production in Africa. Therefore, it is apparent that a high discount rate (cost of capital) represents a significant impediment to the development of renewable energy in Africa. Both Ameli et al. [131] and this thesis uses the present data to represent the country-specific discount rate, which represents that the financial inequality between countries has a similar pattern as that of today. We do see that the discount rate might change over time. Therefore, the value we use as country-specific discount rate is rather indicative than absolute.

As summarized in **Background** chapter of this thesis, a high discount rate is typically linked to investment risks arising from uncertainty regarding the policy environment as well as market and technology risks. To facilitate the deployment of renewable energy in Africa, various measures are needed to reduce investment risks and make investments in renewables more attractive. One way is to improve the institutional capacity to establish stable policy environments, increase transparency, and build robust frameworks [189]. Another way is to offer financial de-risking options such as green bonds, loan guarantees, and policy risk insurances [189]. Nevertheless, considering the regional investment risks, using North Africa to tap solar resources as previously suggested by Refs. [179, 185-188], is perhaps not as economically attractive as the solar radiation data alone might suggest. Additionally, the above analysis emphasizes the significance of factoring in the regional disparity in discount rates when analyzing international energy trade [38, 84, 85].

Nuclear power

This thesis also contributes to the understanding of the role of nuclear power in a future low-carbon electricity system, as discussed in **Papers IV** and **V**. **Paper V** specifically adds to the ongoing discussion regarding the importance of firm low-carbon energy resources (such as nuclear and fossil fuel plus CCS) in achieving deep decarbonization of power generation. Several studies have shown that without firm low-carbon resources, electricity costs rise rapidly as CO_2 limits approach zero [7, 41, 42]. This is because zero-emission systems without firm resources require a large amount of VRE and storage to reliably meet demand during periods of low wind and solar availability. This can result in low utilization rates for these technologies and an increase in overall system costs. Specifically, this thesis quantifies the cost benefit of investing in nuclear power for Sweden and finds that allowing for nuclear power has a limited impact on the net system cost, suggesting that there may be little economic rationale for Sweden to invest in nuclear power. This analysis serves a valuable policy purpose by providing insight into the baseline economic

benefit of nuclear power for Sweden and informing the ongoing political debate regarding the installation of new nuclear power in the country.

Two studies have examined the potential role of nuclear power in Sweden, namely Karlsson et al. [190] and Hong et al. [45]. The former investigated a carbon-neutral scenario for the Nordic region and concluded that the current nuclear capacity in Sweden could be replaced by 31 GW of wind power, which is consistent with the findings of this thesis (30 GW). In contrast, Hong et al. [45] focused on the cost penalty of replacing nuclear power with wind and solar in Sweden and reported a significantly higher electricity cost (five times higher than the results of this thesis) and a greater amount of wind power needed to replace nuclear than what is shown in Karlsson et al. and this thesis. The large escalation of system cost and wind power installation in Hong et al. is mainly due to their heuristic approach, which did not optimize the Swedish electricity system, and their restriction of cross-border trade to historical levels. The drawback of oversimplifying the cross-border trade is already highlighted in the section above. Two studies found a larger cost benefit (11%) of including nuclear power for Europe than what we show for Sweden [159, 191]. One major reason is that Sweden has better hydro resources than Europe on average.

Several studies published after **Paper V** used similar methods as we do to investigate the role of nuclear power and found either limited impact on system cost of allowing for nuclear power in France [192] and Netherlands [157] or a negligible share of nuclear power in the cost-optimal scenarios for the UK [184]. Specifically, Shirizadeh and Quirion [192] showed that the availability of nuclear reduces the electricity system cost by up to 5% for France. Similarly, Fattahi et al. [157] reported that allowing for nuclear in Netherlands has a negligible impact on system cost (<1%). Price et al. [184] found that investing in nuclear power is not cost-optimal for the UK renewable energy system, when it is included as a generation option. Together these studies showed us that there is very limited cost benefit of investing in nuclear power given the cost assumptions for VRE and variation management strategies. These studies also found that there is an obvious competition between nuclear power and other flexibility options [157, 184, 192]. Fattahi et al. [157] reported that with the availability of substantial import potential from neighboring countries, no nuclear is installed for the Netherlands. Likewise, Shirizadeh and Quirion [192] found that the availability of CCS reduces the cost benefit of nuclear power to only 2% for France. In this thesis we find that the cost benefit of nuclear power is enhanced if the storage cost is high (**Paper V**). In **Paper IV**, the availability of cheap nuclear power diminishes the cost benefit of a global super grid to less than 1%. This is mainly because the demand for resource tapping and variation management over a large spatial scope is reduced with the presence of abundant domestic nuclear power. Therefore, the economic prospect of nuclear power is affected not only by cheap VRE resources, but also by the existence of other flexibility options, e.g., hydropower, CCS, storage and trade.

In addition to examining system cost, Fattahi et al. [157] also analyzed the effect of nuclear power availability on electricity prices and found that investing in nuclear power reduces the average electricity price for the Netherlands by 4% to 16%, depending on the availability of other flexibility options. We performed an additional analysis for **Paper V** and found that the availability of nuclear power reduces the average electricity price by 7% for Sweden. The reduction in price for Sweden falls in the low range possibly due to the abundant flexibility provided by the Swedish hydropower. Recently, the new Swedish government changed the energy policy goal from "100% renewable" to "100% fossil-free" with an overwhelming focus on nuclear power as the answer to fossil fuel reliance [193]. One motivation for such change is that nuclear power may reduce electricity price for Sweden. Our additional analysis partially supports this hypothesis, and we suggest that future studies conduct more systematic investigations to fully understand the impact of nuclear power on the Swedish electricity price.

Alternative options for a future low-carbon electricity system

This thesis does not provide a systematic exploration of near optimal solutions for future low-carbon electricity systems. Nevertheless, by examining a system with or without nuclear power or transmission grids, it demonstrates alternative solutions for a future electricity system. In planning future energy systems, modeling studies based on CEMs often concentrate on a single, cost-optimal solution. However, cost optimality alone does not necessarily guarantee social-political feasibility, as it disregards the social and environmental dimensions that are sometimes more crucial for real-world political feasibility [194]. Focusing solely on a single, optimal solution may neglect a range of equally feasible but potentially distinct system configurations. The emerging field of modeling to generate alternatives (MGA) has demonstrated that the feasible decision space is much broader [6, 164, 194-198]. These studies typically reveal the flexibility of options like whether to invest in or where to locate particular technologies. Techniques such as MGA are useful in identifying feasible solutions regarding social acceptance of specific technologies, such as overhead transmission grids, large-scale local onshore wind power, and nuclear power.

In this thesis, allowing for nuclear power in Sweden yields the least-cost solution for the Swedish electricity system. By comparison, excluding nuclear power may result in an alternative system configuration with an increase in system cost of 3%. Similar phenomenon is observed in **Paper IV**, the least-cost system configuration is characterized with abundant cheap nuclear power while an alternative system design without nuclear power can be achieved with enforced transmission expansion and a system cost increase of 6%. This thesis together with the studies [157, 184, 192] discussed above shows that a low-carbon electricity system without nuclear power is feasible and the cost of such a system is comparable to the one with nuclear power.

As for the feasible space of transmission grids, this thesis shows two extremes: Isolated region *vs* Global connection. Grid expansion may enable the share of VRE and dispatchable resources in a larger scope and leads to the reduction of system cost (14% at the continental level and 16 % at global level). Our results also show that the marginal benefit of extending spatial scope via transmission grids decreases as the spatial scope increases. A similar trend is observed in the expansion of transmission capacity within Europe: while significant cost reduction is achieved at a small capacity range, the cost remains relatively stable as transmission capacity approaches the optimal value [3]. Expanding transmission grids within Europe faces social acceptance problems, while a global super grid presents significant political and institutional challenges in integrating power markets between countries, especially those with conflicting interests. As a result, alternative solutions with medium-level transmission expansion in both volume and spatial scope might be the best practical choice given these constraints.

In conclusion, this thesis does not present a comprehensive feasibility space for the design of a future low-carbon electricity system. However, it does provide insights into various future system configurations and quantifies the trade-offs associated with key technologies such as nuclear and transmission. This information can give policymakers the flexibility to craft a preferred approach based on their national priorities.

Future work

This thesis is not an endpoint, but rather a springboard for additional research investigations. The methodologies and tools developed within this thesis can be employed to explore the following research topics.

Nuclear power

This thesis highlights that increasing electricity demand results in a larger cost benefit for nuclear power. Additionally, Price et al. [184] found that nuclear power played a larger role in the cost-optimal scenario during a bad weather year compared to a normal weather year. Therefore, it is interesting to *examine the potential role of nuclear power in a sector-coupled energy system, as well as the impact of extreme weather on its economic viability*. There is no clear answer to this question. On the one hand, sector-coupling can lead to increased electricity demand, which could enhance the role of nuclear power. However, sector-coupling also introduces large-scale flexibilities to the energy system, which could diminish the importance of nuclear power. Furthermore, considering long-term periods of low wind, solar and hydropower output, such as "dunkelflaute" periods, investment in nuclear power might become more attractive. However, extreme weather events, such as heat waves and dry periods, can also impact the reliability of nuclear power by reducing operation efficiency and cooling water supply. Therefore, it is crucial to consider all these factors and conduct a systematic evaluation of the role of nuclear power.

Trade

Paper IV assumes a global carbon cap, but in reality, climate policies vary across different countries. Building a super grid to enable international energy trade may lead to different outcomes in terms of the deployment of renewable energy resources and fossil fuel power plants depending on the regional climate policy. It is therefore crucial to *consider the heterogeneity of climate policies among different countries and assess the potential impact of international energy trade on each country.*

This thesis shows that trading electricity through a global super grid does not enhance the deployment of solar PV. However, findings from **Paper III** indicate that producing hydrogen does lead to an increase in the deployment of solar energy. Hydrogen is cheaper to store than electricity, which makes the production of hydrogen more flexible compared with electricity production. The flexibility of hydrogen production allows for the utilization of cheap solar energy during the daytime. It is interesting to test our hypothesis by *exploring whether a global hydrogen pipeline could promote the deployment of solar energy*.

Hydrogen

The Levelized Cost of Hydrogen (LCOH) is a commonly used metric for measuring the cost of hydrogen production [199-202]. However, LCOH calculations typically focus on a single unit and do not consider how it interacts with the broader energy system. Hydrogen production can create value for the energy system by providing flexibility, which is not captured by LCOH. One approach to correct the caveats of LCOH is to *calculate the system marginal cost of hydrogen*, which can be implemented by adding exogenous hydrogen demand to a CEM and calculating the shadow price of the hydrogen demand constraint. By incrementally increasing hydrogen demand, a series of marginal costs can be obtained that correspond to the hydrogen supply curve. *This supply curve can then be used to assess the quality and quantity of hydrogen while taking into account its value to the system. The supply curve can also be used to identify the important and export potential of hydrogen for different countries.*

Land availability

This thesis partly examines the relationship between land availability, the supply of VRE, and the cost of the electricity system. The growing resistance to wind and solar projects suggests that it may be more challenging to install large-scale VRE projects in densely populated areas. In contrast, remote regions such as deserts and offshore locations may present fewer obstacles. Consequently, it is worth *exploring the trade-off between the cost of the electricity system and the placement of generation and transmission infrastructure in response to social limitations on VRE resource utilization.*

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