THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

Cost-efficient integration of variable renewable electricity

Variation management and strategic localisation of new demand

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Gothenburg, Sweden 2022

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Abstract

The aim of this work was to improve our understanding of how wind power and solar photovoltaics (PV) can be integrated into the European electricity system in a cost-efficient manner. For this, a techno-economic, cost-minimising model of the electricity system is refined for a number of case studies. The case studies cover different geographical scopes, ranging from isolated regions that have different conditions for wind and solar power to larger areas of Europe, and employ various strategies for variation management. Variation management can be provided by strategies that are internal to the electricity system, such as flexible bio-based generation, battery storage, and trade, as well as measures that become available from the electrification of the industry, transportation, and heating sectors.

The results show that there is a need for different variation management strategies (VMS) in different system contexts. In regions with exceptionally good conditions for variable renewable electricity (VRE), wind and solar power integration benefits from absorbing strategies, which create value for electricity at low-net-load and negative-net-load events. In regions where the conditions for VRE are not adequate to out-compete base-load generation, complementing technologies that reduce the net-load during high-net-load events are needed to enable cost-efficient wind and solar power integration. Shifting strategies, which manage variations of short duration and high frequency, are primarily suited to the diurnal variations of solar PV. Solar PV can also be efficient at supplying electricity for hydrogen production for steel or other industries, especially if the demand is flexible over the year, such that the seasonality of solar power does not result in a demand for costly complementing technologies during wintertime. Variation management can increase the cost-efficient share of VRE that can be integrated into the system, while reducing the total cost of meeting the demand for electricity.

One of the strongest VMS covered in this work involves optimising the charging of electric vehicles together with vehicle-to-grid exchange (discharging from electric cars to the grid), which can reduce the cost of electricity generation by up to 33% in a solar-dominated system. The same strategy reduces the cost by only 8% in a wind power- and hydropower-rich region with inherent flexibility, which highlights the importance of context when addressing the future electricity system. Trading electricity through transmission can be useful for integrating wind and solar power, in that transmission can smoothen wind variations between regions and it can transfer electricity from electricity systems with superior wind or solar power resources. A scarcity of bioenergy would entail a high value being placed on available biomass that is to be used for the purpose of complementing wind and solar power. To maximise the provision of flexibility through biomass, it could be utilised with negative-emissions technologies to enable the usage of fossil-derived natural gas. Bio-based generation that is deployed to meet net-negative emissions targets would, however, not provide flexibility. Nonetheless, biomass gasification with carbon capture and storage and utilisation could deliver both a flexible fuel and negative emissions. This could also provide absorbing VMS, if the utilisation part is designed to run flexibly by enabling enhanced biogas production during low-net-load periods.

The combination of transformation and expansion of the electricity system may result in large regional differences in available VRE resources. In addition to transmission, strategic localisation of new electricity demands to regions with good resources becomes beneficial from the perspectives of economics and VRE integration. The results of this work underline the importance of combining different technologies and strategies and demonstrates the value of using them where they are best suited rather than deploying one strategy to tackle every situation.

Keywords: Energy system modelling, flexibility measures, smart energy systems, variable renewable electricity, variation management strategies

List of publications

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

I. V. Johansson and L. Göransson (2019). "Impact of variation management on cost-optimal investments in wind power and solar photovoltaics". *Renewable Energy Focus* **32**, pp. 10-22. DOI: 10.1016/j.ref.2019.10.003

II. M. Taljegard, V. Walter, L. Göransson, M. Odenberger and F. Johnsson (2019). "Impact of electric vehicles on the cost-competitiveness of generation and storage technologies in the electricity system". *Environmental Research Letters* **14**. DOI: 10.1088/1748-9326/ab5e6b

III. V. Johansson, M. Lehtveer and L. Göransson (2018). "Biomass in the electricity system - A complement to variable renewables or a source of negative emissions?". *Energy* **168**, pp. 532-541. DOI: 10.1016/j.energy.2018.11.112

IV. J.M. Ahlström, V. Walter, L. Göransson and F. Papadokonstantakis. "The role of biomass gasification in the future flexible power system – BECCS or CCU?". *Renewable Energy* **190**. DOI: 10.1016/j.renene.2022.03.100

V. V. Walter and L. Göransson (2022). "Trade as a variation management strategy for wind and solar power integration". *Energy* **238**. DOI: 10.1016/j.energy.2021.121465

VI. A. Toktarova, V. Walter, L. Göransson and F. Johnsson (2022). "Interaction between electrified steel production and the north European electricity system". *Applied Energy* **210.** DOI: 10.1016/j.apenergy.2022.118584

VII. V. Walter, L. Göransson, M. Taljegard, S. Öberg and M. Odenberger. "Low-cost hydrogen in the future European electricity system – Enabled by flexibility in time and space". Submitted.

Viktor Walter (previously Johansson) is the principal author of **Papers I**, **III**, **V** and **VII**, and conducted most of the modelling and calculations for these papers. **Paper II** is the result of joint work with Maria Taljegård, where the author contributed with analysis, discussion and editing. **Paper IV** is the result of joint work with Johan M Ahlström, where the author contributed with modelling, analysis, discussion and editing. For **Paper VI**, the author contributed with modelling and discussion. Lisa Göransson contributed with modelling and analysis to **Paper I**, with writing to **Paper VII** and with discussion and editing to all of the papers. Mariliis Lehtveer contributed with analysis, writing, discussion and editing to **Paper III**. Mikael Odenberger contributed with discussion and editing to **Papers II** and **VII**. Filip Johnsson contributed with discussion and editing to **Papers II** and **VI**. Simon Öberg contributed with discussion to **Paper VII**.

Other publications

Other publications by the author, not included in the thesis:

A. V. Johansson, L. Thorson, J. Goop, L. Göransson, M. Odenberger, L. Reichenberg, M. Taljegard and F. Johnsson (2017). "Value of wind power – Implications from specific power". *Energy* **126**, pp. 352-360. DOI: 10.1016/j.energy.2017.03.038

B. V. Johansson, L. Thorson and L. Göransson (2017). "A quantitative method for evaluation of variation management strategies for integration of renewable electricity". *Proceedings of the 16th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants*. Berlin, Germany.

C. L. Göransson, M. Lehtveer, E. Nyholm, M. Taljegard and V. Walter (2019). "The Benefit of Collaboration in the North European Electricity System Transition—System and Sector Perspectives". *Energies* **12**. DOI: 10.3390/en12244648

D. P. Holmér, J. Ullmark, L. Göransson, V. Walter and F. Johnsson (2020). "Impacts of thermal energy storage on the management of variable demand and production in electricity and district heating systems: a Swedish case study". *International Journal of Sustainable Energy* **39**, pp. 446-464. DOI: 10.1080/14786451.2020.1716757

E. M. Lehtveer, L. Göransson, V. Heinisch, F. Johnsson, I. Karlsson, E. Nyholm, M. Odenberger, D. Romanchenko, J. Rootzén, G. Savvidou, M. Taljegard, A. Toktarova, J. Ullmark, K. Vilén and V. Walter (2021). "Actuating the European Energy System Transition: Indicators for Translating Energy Systems Modelling Results into Policy-Making". *Front. Energy Res.* **9**. DOI: 10.3389/fenrg.2021.677208

F. E. Malz, V. Walter, L. Göransson and S. Gros (2021). "The value of airborne wind energy to the electricity system". *Wind Energy* **25**, pp. 281-299. DOI: 10.1002/we.2671

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Viktor Walter
Ljungskile, May 2022

Table of Content

1 Introduction

Global responses to climate change, setting the goal of restricting global warming to well below 2°C above pre-industrial levels, were agreed upon in Paris in 2015 [1]. To meet this target, rapid decarbonisation of all energy sectors is needed, together with large-scale deployment of negative-emissions technologies [2]. Transformation to a carbon-neutral electricity system and electrification of other sectors are identified as key tools for tackling this challenge [3]. The electricity sector can be decarbonised through a mixture of renewable sources, carbon capture and storage (CCS), and nuclear power. Each of these solutions entails specific economic, social and technological challenges. Wind power and solar photovoltaics (PV) are promising technologies due to their low costs and high technical potentials. Utilising weather-based resources does not result in any direct CO_2 emissions, and the life-cycle emissions are low. However, given that the electricity generated by wind power and solar PV is dependent upon the weather, the supply is variable. Due to weather variations that occur on different time-scales, the generation becomes irregular, resulting in difficulties with utilising variable renewable electricity (VRE) for meeting the demand. Balancing variable generation and demand in time is regarded as one of the main challenges associated with achieving high shares of VRE in the electricity system [4]. Mismatches associated with the location of demand for electricity and availability of economic areas for wind and solar power generation adds a spatial dimension to the challenge of VRE integration.

There are numerous flexibility measures for managing the variability of wind power and solar PV, some of which also enable the utilisation of resources that are distal from centres of concentrated demand. Lund et al. (2015) have divided flexibility measures into the following categories with the five main measures for inter-hourly balancing of generation and demand: energy storage; demand-side management (DSM); supply-side management; "advanced technologies"; and infrastructure [5]. Energy storage refers to power-to-power storage units, for example batteries or pumped hydropower. Infrastructure measures refer to grid measures, such as building a super-grid to connect remote resources to demand, as well as utilising geographical smoothing effects. Supply-side management involves increasing the cycling of dispatchable units to save fuel during low-net-load events or increasing the capacities of flexible units such as gas turbines, which can be fuelled with methane from fossil (natural gas) or biogenic (biogas) sources. DSM refers to altering the load pattern of the electricity consumption, for example for household appliances. "Advanced technologies" or more-commonly sector coupling, refer to the utilisation of electricity for services in other sectors, where other forms of flexibility are available at a lower cost than in the electricity system. All of these measures are, however, linked to social, environmental and/or economic costs. Thus, efficient utilisation and combination of these measures are important for the sustainable integration of VRE at large scale.

The issues and opportunities related to VRE integration can be investigated in energy system optimisation models. This modelling allows assessments of how the conditions in different regions, with different weather conditions, can cope with the VRE integration without having to conduct tests in the real world. Energy system modelling can, therefore, reveal how different constraints affect the energy transition and identify areas that are more or less important and in need of policies or actions to achieve the transition. Here, energy system modelling is used to improve our understanding of how supply and demand can be balanced in time and space through variation management strategies (VMS) designed for different scenarios and different contexts of the future electricity system.

1.1 Aim and scope

This thesis focuses on elucidating: (i) how increased flexibility, both temporal and spatial, can facilitate VRE integration; and (ii) the societal and economic values of different modes of flexibility. These questions are addressed in the European context with the time-frame of a future year, i.e., balancing variations from hours up to a year in a future electricity system with low carbon emissions. The questions are addressed in the appended papers, which describe case studies directed towards answering the following questions:

- How will different variation management technologies, applied either separately or in combination, affect the cost-optimal composition of the electricity system?
- With regard to filling the current knowledge gap regarding bioenergy in the electricity system:
    - What is the value of bioenergy in the electricity system?
    - Which biomass-based technologies should be part of the least-cost electricity system under various biomass supply conditions and with different emissions targets?
    - Under which conditions do biomass-based technologies and variable renewables act as complements or competitors within the electricity system?
- How do electric vehicles influence the cost-competitiveness of generation and storage technologies in the electricity system?
- In what ways do the design and operation of gasification plants with carbon capture and storage and/or utilisation interplay with the design of the electricity system?
- What are the impacts of different transmission features, i.e., as enablers of VRE resource transfer from remote areas and as agents for geographical smoothing, on the integration of VRE, in relation to other VMS?
- How can the electrification of the steel industry influence the spatial allocation of future steel plants and their sizing, and what are the impacts of an electrified steel industry on investment decisions related to new electricity generation capacity?
- In what ways are the source and cost of hydrogen from electrolysis dependent upon the size and both the temporal and spatial flexibility of the hydrogen demand; how does this hydrogen demand affect the need for flexibility and the cost for other electricity consumers?

This thesis covers wind and solar power integration in a European context. The number of modelled time-steps is reduced as the geographical scope is increased, as shown in Figure 1. In **Paper III**, three European countries/regions, Hungary, Ireland, and central Spain, are modelled to capture the different conditions for generation from wind and solar power. Central Sweden (the Stockholm price area) is included in the group of regions for **Papers I**, **II** and **IV**, to capture the interactions with hydropower. Two base regions, Hungary and Ireland, are connected to other European regions with similar annual electricity demands in **Paper V**, to address the roles of transmission. The geographical scope is further expanded in **Paper VI** to cover Northern Europe, and in **Paper VII** to cover most of Europe.

Paper I considers the potential electricity demand for industrial hydrogen, the opportunity to sell heat from electricity for district heating purposes, and the possibility to shift in time part of the household demand for electricity. Electrification of light vehicles and the charging strategies for such vehicles are assessed in **Paper II**. In **Paper III**, the supply of biomass, biomass conversion technologies, and the carbon emissions limit are subjected to analysis. Carbon capture and storage, as well as utilisation of biomass gasification plants to enhance biomethane production or to generate negative emissions represent the main focus of **Paper IV**. Trade of electricity towards addressing the roles of transferring resources in reducing resource scarcity and the demand for flexibility is analysed in **Paper V**. In **Paper VI**, the iron and steel industries are included to address the value of process flexibility (both spatial and temporal). **Paper VII** includes different levels of hydrogen demand with different freedoms in cases that represent when and where the hydrogen demand is located in time and space.

The temporal scope is a future year around Year 2050, modelled with a chronological one-hourly resolution in **Papers I** and **II** and three-hourly resolution in **Papers III**, **IV** and **V**. The temporal resolution is reduced to 730 chronological time-steps in **Papers VI** and **VII**.

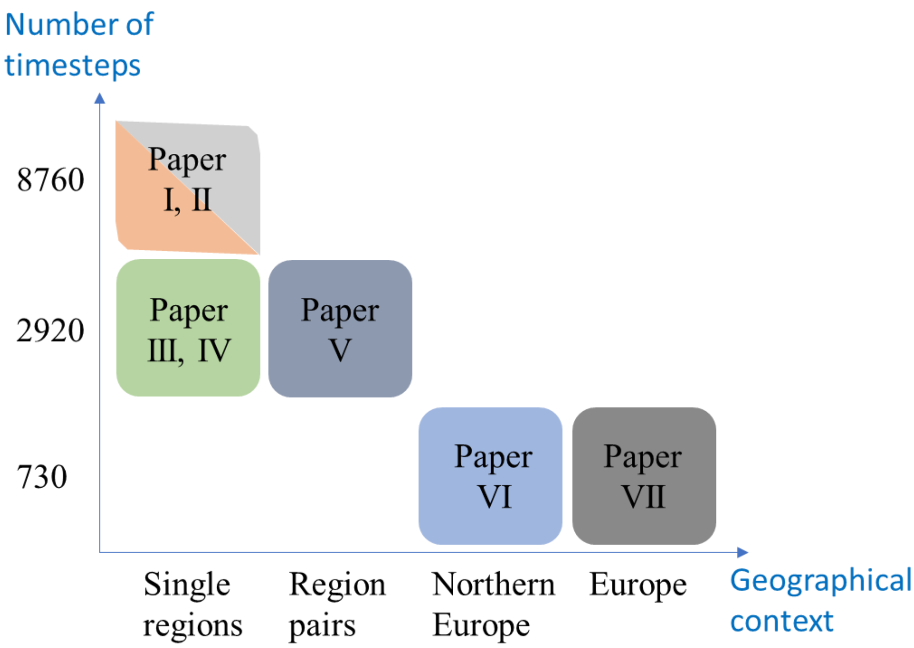

Figure 1: Number of time-steps and geographical contexts of the appended papers.

1.2 Contribution of this thesis

Flexibility measures for balancing the electricity system on an hourly basis within a single year are in this work referred to as ‘variation management strategies’ (VMS). VMS are categorised into absorbing, complementing, and shifting strategies, on the basis of economics and functionality [6]. This work contributes to understanding the roles of flexibility measures, such as electricity storage and electrification strategies for sectoral coupling, applied separately or in combination. **Paper I** covers several of the strategies, so as to capture the impacts from the three VMS categories. Based on the results shown in **Paper I**, the categories proposed previously [6] are refined to capture the functionalities of the VMS, revealing ways to handle frequent variations (shifting) or durable and rare high- (complementing) and low- (absorbing) net-load events (see the VMS triangle [7] in Figure 2). The geographical scope is chosen so as to address the different possibilities for generation from VRE and to capture the need for variation management in regions with different VRE resources. In **Papers II–V**, more-specific variation strategies are addressed, and the VMS triangle is further explored. In **Papers VI** and **VII**, the spatial dimension for the allocation of new electricity demand as well as process flexibility for hydrogen-consuming industries are addressed as measures for VRE integration. The available VRE resources are limited in all the papers, albeit with more-intense focus in **Paper VII**, where the electricity demand is increasing greatly. For the purpose of exploring additional aspects of resource scarcity, **Paper VII** includes cases with reduced levels of acceptance of both VRE and nuclear power.

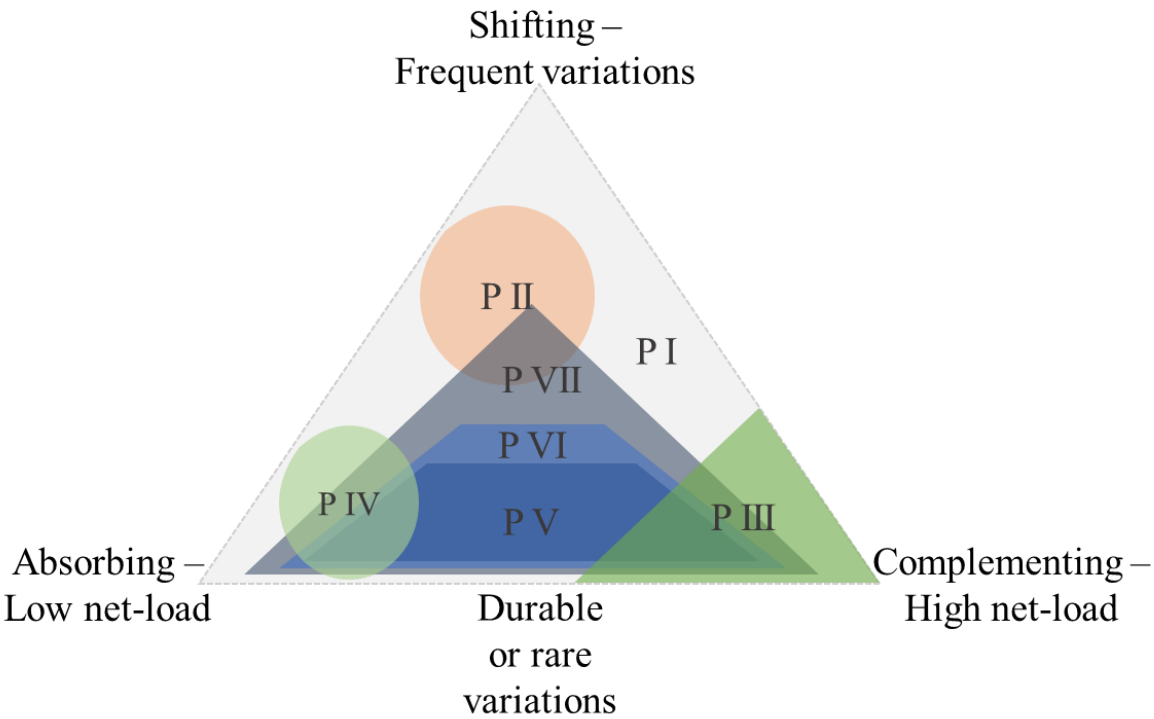

Figure 2: The variation management triangle, indicating the parts explored in each of the appended Papers.

2 Background and related work

Historically, the electricity demand has been the main source of variability in the electricity system, with one or two daily peaks and seasonal variations in some countries related to increased usage of electric heating during cold periods of the year. In response to these variations, base-, intermediate-, and peak-load technologies have been applied [8]. Base-load technologies typically have a high investment cost and low running cost, giving a low cost for energy when run at full capacity for most of the year. In contrast, peak-load technologies are expensive to run and have a comparatively low investment cost; they are run for only a few hundred or thousand hours per year and are fast-ramping. Intermediate-load technologies cover the interval between base-load and peak-load technologies. The merit order in terms of load-handling technologies for use in the system is based on the variable cost of generating electricity from the different technologies.

Since wind and solar power generation technologies incur no or low variable costs, they are placed early in the merit order, and the load variations are joined by the variations in supply. The net-load is calculated by subtracting the VRE generation from the load. As the levels of wind and solar power increase within the electricity system, the variations in net load go from being dependent upon the demand to being characterised to a greater extent by the weather-based generation patterns. In systems that are supplied to a large extent by VRE, high-load hours with no or low-level generation from VRE are *high-net-load hours*, and hours during which a large share of the load is covered by VRE are *low-net-load hours*. The electricity price is typically set in accordance with the marginal cost of production, which is low during low-net-load hours and high during high-net-load hours. Thus, the increasing shares of wind and solar power cannibalise the profitability of the total fleet of wind turbines and PV panels, respectively, as the production of the whole fleet follows the same weather patterns [9]. Thus, VMS are beneficial not only in terms of balancing the demand and supply, but also for sustaining the value of VRE.

This chapter describes variations in demand related to wind power and solar power. It also covers the role of different VMS and how these are modelled in energy system models with large shares of VRE.

2.1 Variations in demand, wind power and solar power

The variability of wind power and solar power (as well as that of generation using wave and tidal resources) has been reviewed by Widén et al. [10]. For solar power, the generation profile shows both diurnal variations and seasonal variations that depend on the latitude of the solar power installation. In addition, the cloudiness and temperature cause the profile to deviate from the theoretical production under clear sky conditions (which are perfectly predictable for any location). The wind power variations are presented as more-random in nature, as the production profile exhibits large variations on a time-scale of a few hours to a few days. The smoothing effect for wind power in different countries has been studied previously [11], showing that generation on an hourly level shows a low correlation between neighbouring countries and the correlation increases with time, so that wind power profiles all over Europe show a positive correlation with that of a central region for time-scales >4 months.

Temporal smoothing influences wind power and solar power differently due to the difference in temporal variability. Figure 3 shows the wind, solar, and demand profiles with hourly data, as well as with rolling averages over days (24 h) and weeks (168 h) for a month in central Sweden. Figure 4 shows the weekly rolling averages for wind, solar, and electricity demand for the entire year in central Sweden and central Spain. The variations in the wind profile are scarcely smoothed by the daily averages. Yet, with the weekly averages, the curve shows more than 2-fold higher generation in a good week compared to a poor week in the specific month. Weekly smoothing of variability results in much more even generation, albeit with relatively large variations still being present. For solar power, the smoothing effect is strong for days, and the weekly averages result in only marginal additional smoothing. With respect to the demand, daily smoothing leaves mainly week/weekend variations, and with weekly smoothing only the long-term trend due to seasonal variations remains.

Figure 4a shows large seasonal variations in solar power and demand for Sweden, with a negative correlation between them. The seasonal variations are smaller for both solar power and the demand in central Spain (see Figure 4b). In Spain, (smoothed) solar power has a long period with even, high-level production and a short low-production period of 2–3 months when the generation on average is about 50% of that during the high-production period. The variations in wind power are large on a weekly time-scale in both Sweden and Spain.

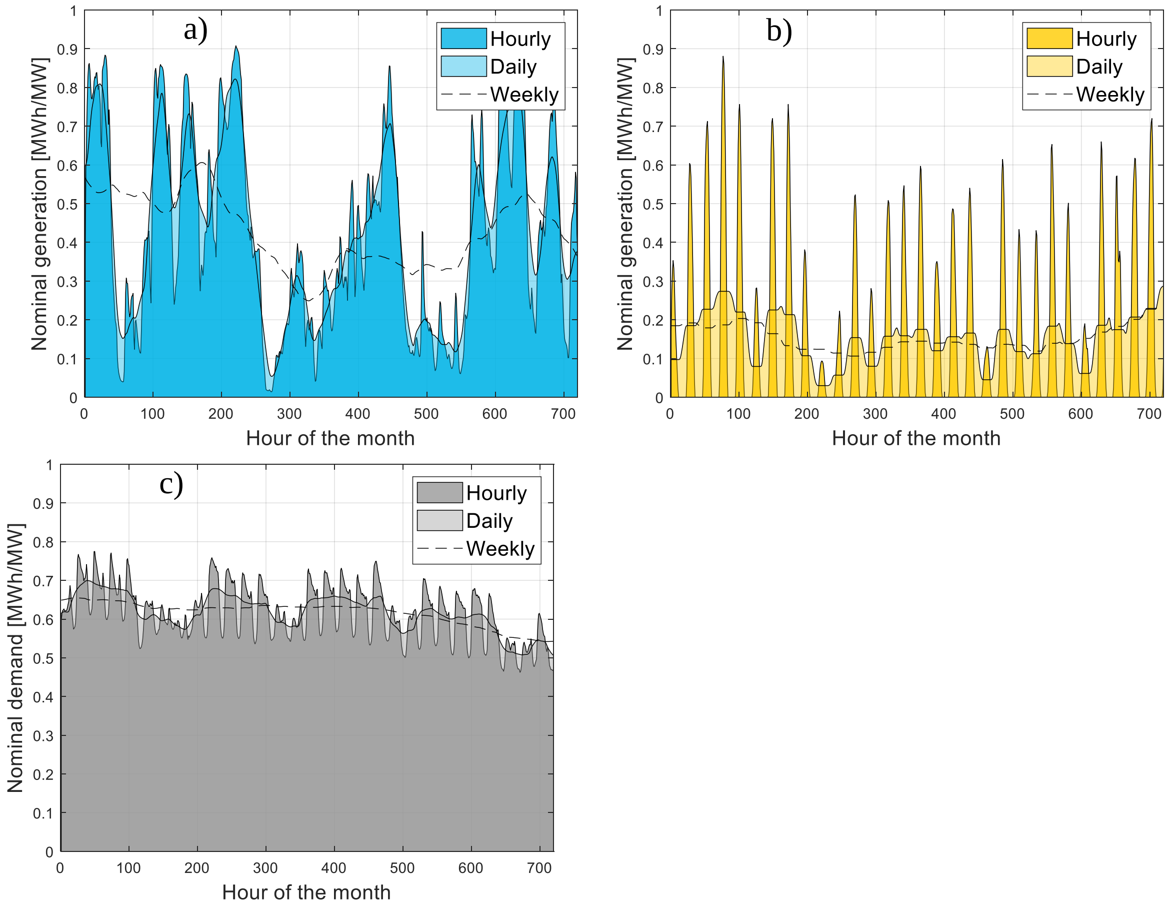

Figure 3: Generation and demand profiles for: (a) wind power; (b) solar power; and (c) electricity demand for central Sweden for a spring month. The daily (24 h) and weekly (168 h) profiles are rolling averages of the hourly data. Sources: wind and solar profiles, ***Paper VII****; demand profiles,* ***Papers I–VII****.*

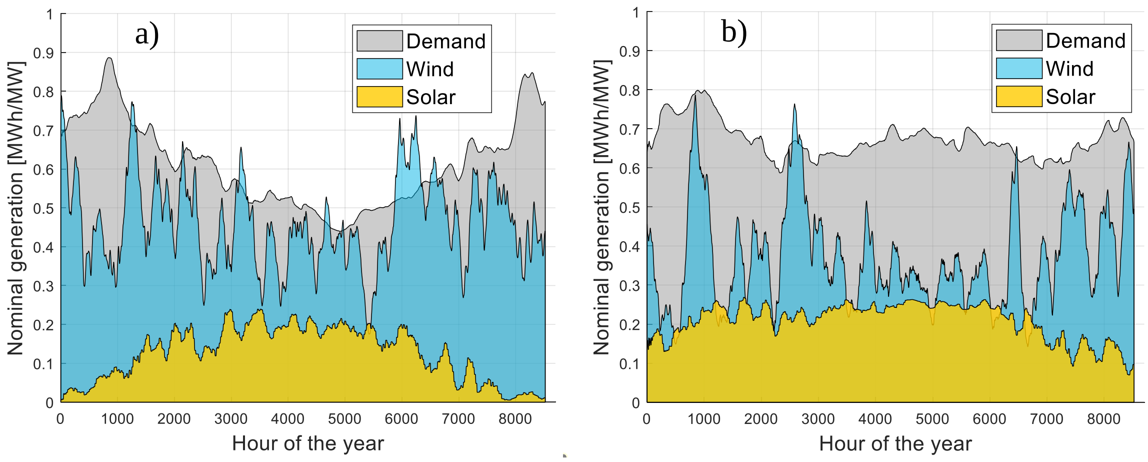

*Figure 4: Demand, wind power, and solar power profiles for: (a) central Sweden; and (b) central Spain. The data are smoothed with weekly (168 h) rolling averages. Sources: wind and solar profiles, **Paper VII**; demand profiles, **Papers I–VII**.*

2.2 Flexibility and variation management strategies

In general, flexibility is the ability to react to variations and, thus, to adopt alternative actions. In the supply side, alternative technologies offer flexibility regarding the fuel, emissions, and ramping time. Storage units provide flexibility in time and can be *explicit*, as is the case with batteries that have the sole purpose of shifting electricity consumption in time, or *implicit*, as in the case of thermal heat storage in buildings, which gives inertia to changes in the weather. Flexibility measures include conventional flexible generation technologies, energy storage units, and trade to demand-side options to control the current demand, as well as the use of electricity for new purposes in other sectors [5]. Overall, many technologies offer alternatives for balancing variations in the supply and demand of electricity. The time-frame over which the many flexibility measures maintain the balance ranges from milliseconds to several months or years. Flexibility measures for balancing the electricity system on an hourly basis within a single year are in this work referred to as VMS, and they are categorised as *absorbing*, *complementing*, and *shifting* strategies, on the basis of functionality [6]. The cost-efficient functionality of a VMS is largely determined by its cost structure.

Shifting strategies handle frequent variations in high- and low-net-load periods. Shifting strategies are characterised by a low cost for charging and discharging capacity, albeit with storage limitations, which are linked to a relatively high investment cost or technical constraints that limit the duration of the storage. Both explicit and implicit storage systems can be used as shifting VMS. In general, complementing VMS reduce the strain on the electricity system during high-net-load periods and absorbing VMS support the system during low-net-load periods. A technology can have the possibility to be either absorbing or complementing depending on the strategy and system context, since wind and solar power have different needs for handling durable variations at different locations.

Extensive electricity system optimisation modelling that includes different VMS has been carried out in recent years, and some of these have been presented in a review [12]. Modelling studies with VMS cover topics that include dispatchable (thermal or hydropower) generation, design and operations of VRE, battery storage, transmission, and sector coupling.

2.2.1 Dispatchable generation

The main technologies that are available for dispatchable electricity generation are thermal units, which have historically been fuelled with fossil coal, natural gas, and oil or the extracted heat from nuclear fission of enriched uranium. While the fossil fuels could be replaced by biogenic equivalents, the extent to which fossil fuels are used is far greater than the extent to which sustainable biogenic fuels are available. In addition to thermal technologies, reservoir hydropower is dispatchable to a significant degree.

The role of thermal generation in relation to the share of VRE has been examined previously [13]. There are thermal generation technologies that can serve as base-load, intermediate-load, and peak-load technologies that fit well with the historical load variations. At a low level of VRE, the electricity system mainly comprises base-load, which is totally phased out at about 50% VRE, after which more-flexible peak-load generation from e.g., gas turbines are the dominating dispatchable sources of electricity [13]. To address the choice of thermal units and the potential flexibility of, in particular, intermediate-load generation, it is important to represent the cycling properties of these thermal units [14]. These properties relate not only to technical constraints but also to cost, as plants could be designed to be more flexible at an increased cost. However, as additional cost increases the need for revenue, improving the technical flexibility reduces the economic flexibility, although it could still be of value in terms of additional VRE integration [15]. Providing scope for wind power and solar PV generation by reducing the electricity production to the minimum compliant load in thermal base-load or intermediate-load generation units is an absorbing strategy for the integration of VRE into electricity systems that are dominated by thermal generation. Flexible peak-generation technologies can complement VRE during high-net-load events.

Hydropower can be operated in such a way as to integrate wind power in a fashion similar to that of flexible thermal generation, which increases the value of VRE [16]. The flexibility of a hydropower plant is directly affected by the inflow, storage, and capacity parameters. However, it is also indirectly affected by the dimensions of and lead-times from upstream plants. Thus, hydropower plants may be designed to provide intermediate-load or peak-load generation. In this thesis, hydropower generally refers to reservoir hydropower, whereby the water can be stored and subsequently dispatched.

2.2.2 Design and operation of VRE

As an alternative to absorbing the generation peaks from VRE, some of the generation can be curtailed to avoid a negative net load (or to avoid the high cycling costs of thermal generation), which results in a zero price for electricity. Curtailment has no economic value as such, except that planned curtailment may have a value with respect to up-regulation in reserve markets [17]. The wind turbines can also be designed to produce electricity in a more system-friendly way, through reaching the maximum output earlier and thereafter curtailing more of the wind energy before it is converted to electricity [9], [18], [19]. This design allows more wind power to be installed before cannibalising its own value, while at the same time increasing the investment cost and creating a lower capacity density, which means that more land would be required to attain the same annual level of generation from wind power. Regarding solar power, single- or dual-axis tracking increases the output and makes it less-peaky. The tracking systems increase the investment and maintenance costs of the solar PV but might reduce the need for other VMS.

2.2.3 Battery storage

Batteries are strongly linked to VRE integration. Temporal smoothing of the electricity generation from VRE provides the possibility to utilise weather-based electricity with a higher degree of freedom. The cost of battery storage requires a relatively high number of cycles to give a low cost per unit of stored electricity, which better suit the diurnal solar power variations than the less frequent variations in wind power. The combination of reduced cost for batteries and solar PV has been shown to have a strong positive impact on the integration of solar power as well as on reducing the average cost of electricity generation in Europe and MENA [20]. Low-cost battery storage has also been shown to allow solar PV to become the major source of electricity in the US, in competition with fossil fuels and without policy interventions [21].

2.2.4 Transmission

Geographical variations in weather patterns can be used to smoothen variations in weather-based generation [22]. Wind power benefits from geographical smoothing on different distance and temporal scales due to the movement of weather patterns [23]. Trading of electricity can not only confer flexibility, but it can also enable the transfer of VRE resources between regions that have different conditions for the expansion of VRE [24]. Transmission has also been investigated in combination with the implicit storage in household DSM in a dispatch model, in which it has been shown to reduce the need for peak generation [25]. The time period for which electricity consumption in households can be delayed is, however, expected to be too short to have a significant impact on durable wind variations. Reichenberg et al. [26] have demonstrated how wind and solar power, together with transmission and batteries are efficient at achieving system integration levels of 85%–98% VRE before the integration costs skyrockets, which also highlights the difficulty associated with covering the remaining fraction in the absence of flexible generation technologies. At high levels of VRE, wind power accompanied by transmission expansion competes with solar PV accompanied by batteries [26], [27].

2.2.5 Sector coupling

Electrification of other energy sectors, or sectoral coupling, refers to the expansion of the electricity system so as to cover parts of the energy demands for other sectors, such as for heating, transportation, and industries. These sectors are especially interesting due to the low-cost storage options for other energy carriers, such as hot water for heating or hydrogen for industry. Combining different sources of flexibility and expanding the system from the traditional electricity system to other sectors are of importance for the large-scale integration of wind and solar power [28]. Combinations and comparisons of several different VMS show that electrification strategies are more important than short-term storage options in the wind-dominated northern European context [29], [30]. In a conceptualised way, the impact on the net-load duration curve from the utilisation of storage systems and sector coupling for moving and using excess VRE production can be seen [31]. The difficulty of eliminating the last high-net-load periods to achieve 100% VRE systems, despite extensive expansion of the electricity system into other sectors, highlights the need for seasonal storage systems.

The importance of flexibility in sectoral coupling is highlighted by, for example, electrification of the transport sector. Large-scale integration of electric vehicles into the electricity system increases the electricity demand, and if charged directly when parked these vehicles could increase the variability of the load. Smart charging and discharging of cars back to the grid (vehicle-to-grid, V2G) may be important in terms of flexibility provision [32]. Most of the electricity system costs for covering the demand for electrified transportation can be saved by smart charging of the electric vehicles rather than charging the vehicles directly when they are parked [33]. These results hold true when vehicle charging is constrained by driving patterns, as given by driving behaviours from GPS (global positioning system) data [34].

Studies of electric heating show that a district heating system can benefit from wind power integration by switching between generating electricity together with heat in combined heat and power plants and consuming electricity for heat generation in electric boilers and heat pumps [35]–[37]. This gives the possibility to absorb low-cost electricity during low-net-load events. When used in combination with heat storage the impacts are greater than if the heat is required to match the heat demand directly.

Hydrogen production from electrolysis may become a major electricity consumer when the hydrogen gas is used for fuelling industries, transportation and peak-load electricity generation [38]. A comparison of the industrial usage of hydrogen and its use for electricity storage with subsequent conversion back to hydrogen using fuel cells reveals that the industrial usage yields greater savings, since excluding the fuel cells provides savings in terms of both cost and efficiency losses [39]. The steel and fertiliser industries are likely to undergo transformations involving the use of hydrogen produced from electrolysis. Electrification of steel-making is presented in [40], and the potential for meeting the demand with low-cost electricity is assessed in [41]. The production of ammonia using hydrogen from electrolysis for the creation of fertilisers is modelled in [42], where the benefit of low-cost transport and storage for ammonia as the intermediate product provides flexibility in both time and space, while providing ammonia at a competitive price. Furthermore, the production of hydrocarbons for fuel or material purposes is considering to reflect increased usage of hydrogen in combination with CO_2, referred to as CCU (carbon capture and utilisation). The process of plastic recycling with the addition of hydrogen has been presented [43], whereby different stages involving electrification and gasification of recycled plastic are implemented until 100% circularity is achieved. Enhanced biofuel production has been modelled for a case study of Denmark in which electrofuels may play an important role in reducing the import of fuels [44]. The application of CCU is, however, debated given that: 1) there are lower-cost alternative solutions for the transport sector that involve optimising the usage of fossil fuels and negative emissions [45]; it has a high cost; it has limited climate effectiveness; and there are uncertainties linked to its availability, which may lead to a continued demand for fossil fuels [46]. Another energy-intensive technology which might be needed for attaining negative emissions in the future is direct air capture of CO_2. The direct air capture process has been shown to be a promising technology for the consumption of low-cost wind and solar power in a dispatch model [47] and in an investment and dispatch model [48].

Recent studies have shown the electricity system benefits derived from VMS, which are combined in a more holistic perspective (including larger geographical scope, several sectors and storage alternatives), result in weaker individual importance of VMS [49], [50]. Still, transmission and batteries, as well as the utilisation of storage systems in heating, industries and transport sector can be of importance in combination for VRE integration. A Nordic-Baltic pathway study has shown that wind and solar power expansion results in the lowest-cost system, including variation management through trade, storage, and sector coupling [51]. That study supplied several policy recommendations that can be important for enabling price signals to reach producers and consumers, to support cost-efficient reactions to variations in VRE generation. Lux and Pfluger (2020) have addressed the potential cost of green hydrogen production in the European context after first meeting the historical electricity demand, as well as the demands for electrified light and heavy transport and heating [52]. Due to the substantial increase in demand for electricity, the remaining wind and solar power resources can only supply green hydrogen at relatively high cost, despite generous assumptions regarding the flexibility of the hydrogen demand in both time and space. These studies imply that sector coupling can lead to reduced need for other VMS, thus, it has a positive impact on VRE integration in absolute terms. However, the increased demand leads to exhaustion of available resources for VRE may lead to larger dependence on other energy sources and thereby risks having a negative impact on VRE integration in relative terms.

3 Method

Throughout this project (Papers I–VII), the same model, ENODE, has been used to address questions regarding the technologies and strategies that furnish the electricity system with variation management. As part of the present work, certain features have been added to the model. Some of these features have become standard items, while other features are used only in specific papers. The work is carried out in the form of case studies that capture the interactions between technologies in the electricity system for different system contexts, as summarised in Table 1. The system contexts in the model comprise the temporal, spatial, sectoral and technological dimensions, which are explained below.

ENODE (wordplay on the original in-house name in Swedish and English), which is a linear optimisation model that is written in GAMS. A simple overview of the main parts of ENODE and the inputs and outputs is shown in Figure 5. It was first presented in the paper of Göransson et al. [14], wherein it was designed to capture the interplay between VRE and thermal generation technologies. Subsequently, it has been used to address variation management in several projects. The model minimises the total cost of annualised investments and dispatch for a Greenfield electricity system (i.e., the model builds a system without considering the power plant fleet of today, with the exceptions of existing hydropower capacity and transmission lines), with net-zero carbon emissions for one future year, with perfect foresight. In the electricity system modelling, importance is attached to the resolution of different dimensions, including time, space, technologies and boundaries with other parts of the energy system, such as the potential electrification of other sectors.

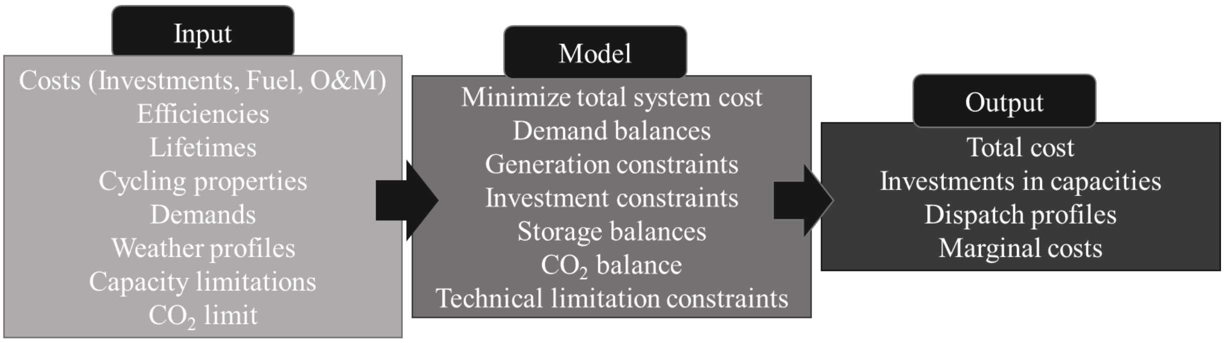

Figure 5: Simple overview of the ENODE model.

Table 1: Summary of the studies described in the appended papers, including the modelling dimensions. Specific technologies refer to features that are added to or further developed in the model in the paper.

	Case study	Time	Geographical Regions	Sectors	Specific Technologies
Paper I	Several VMS[1] separately or in combination	Hourly for 1 year	Central Spain, Hungary, Ireland, central Sweden	Electricity, Heating, Hydrogen-consuming industry	Batteries, DSM[2], Electrolysis and Hydrogen storage, Electric boilers
Paper II	Charging strategies for electric vehicles	Hourly for 1 year	Central Spain, Hungary, Ireland, central Sweden	Electricity, Transportation	Electric vehicles*
Paper III	Efficient usage of biomass; Negative emissions	3-hourly for 1 year	Central Spain, Hungary, Ireland	Electricity	BECCS[3], Fuel cells, Gasification
Paper IV	Flexibility from biomass gasification with CCS and CCU	3-hourly for 1 year	Central Spain, Ireland, central Sweden	Electricity	BECCS[3], CCU[4], Gasification
Paper V	Transmission features – Geographical smoothing and resource transfer	3-hourly for 1 year	Hungary, Ireland, (western Germany, eastern France, southern Poland, Romania)	Electricity, Biomass gasification	Transmission
Paper VI	Design and location of electrified steel production	12-hourly for 1-year	Northern Europe (12 regions)	Electricity, Steel industry	Steel industry (DR[5] shaft, EAF[6], electrolysis)*, Transport of iron commodities*, Transport of electricity
Paper VII	Potential to meet a large demand for hydrogen with VRE, under different cases of hydrogen demand flexibility	730 consecutive time-steps for 1 year	Europe (22 regions)	Electricity, Transportation, Heating, hydrogen consuming industry	-

[1] VMS, Variation management strategies
[2] DSM, Demand-side management
[3] BECCS, Bioenergy with carbon capture and storage
[4] CCU, Carbon capture and utilisation
[5] DR, Direct reduction
[6] EAF, Electric arc furnace
[*] These model features are added by the main authors of the papers,

3.1 Case studies

In the case studies, the assumptions made regarding a wide range of parameters are studied. These can be summarised as: technological costs and availability; flexibility of cost and supply of fuels; demand size and flexibility; and limits regarding CO_2 emissions and intangible benefits from the current system. The geographical scope is single type-regions in **Papers I–IV**, type-pairs in **Papers V**, and larger parts of Europe in **Papers VI** and **VII**. Expansion of the geographical scope was possible while maintaining a high level of technological detail due to reduction of the temporal scope. Reduction of the temporal scope was made possible by the increased robustness of the results due to a reduction of the cost for VRE, as well as the increasing certainty that batteries are becoming a sufficiently low-cost solution for handling short-term variations from solar power.

There are multiple dimensions and levels of detail in energy systems modelling. The level of detail is determined by the geographical scope, temporal scope (both for the investment horizon and number of time-steps per year), number of technologies, and the boundaries with the rest of the energy system. In all the work presented here, the modellers have had to choose the scope in order for the model to be feasible. In **Papers I–V**, there is a high level of detail with regards to the number of time-steps per year, as well the number of technologies represented, including the technologies that are employed for variation management. There are lower levels of detail with regards to the other dimensions, with parts of other sectors or an extra region added one-by-one to address specific questions. If all the VMS were to be included in the most-flexible settings, i.e., with both sectorial and geographical coupling, the individual effects of the VMS options would be reduced. The step-wise additions of VMS in this work, however, provide information that increases our understanding of the impacts of VMS on both investments in and operations of the electricity system.

In **Papers VI** and **VII,** the geographical dimension is addressed by including possibilities for trading electricity, as well as by allowing the localisation of industrial demand for electricity and hydrogen to be influenced by access to low-cost electricity from VRE. In these papers, it is evident that flexibility in the spatial dimension influences the amount of VRE that can be integrated as well as the internal competition between wind and solar power. The reduced temporal resolution of these papers affects the ability to capture details on the time-scale of a few hours. It works well because the robustness of the batteries allows short time-scale shifting of solar power and because of the slow variations in wind-dominated systems. Thus, that time-scale has only a minor impact on the dimensioning of the electricity system.

In **Paper I**, several VMS are included separately or in combination. In **Paper II**, in which the role of electric vehicles is investigated, the battery size, charging strategy, share of participants, and charging infrastructure are varied between the cases. In **Paper III**, the supply of biomass is addressed as the ratio (in the range of 0–1) of the primary energy in the biomass to the annual electricity demand. Within this study, two other parameters are varied: i) the target of either net-zero emissions or negative emissions (100% or 110% less than the electricity system emissions in Year 1990); and ii) whether or not CCS technologies are allowed. In **Paper IV**, the availability of biomass is varied to examine the effects of saturation on the interplay between gasifier design options and investments in the electricity system. Several parameters can affect this interplay. Thus, a carbon emissions tax, the biomass price, the gasifier design options, and the cost of solar PV and batteries are all varied. In **Paper V**, the trading regions, transmission costs, and the wind profile differences (whether or not the regions have synchronised profiles, with either a stable or unstable profile) are varied, to assess the relative importance of two different transmission features. In **Paper VI**, the dimensioning and location of the electrified steel industry in Northern Europe is co-optimised with the electricity system. As this system relies on both a domestic and imported supply of iron ore, as well as hydrogen and electricity for operating the processes, the transport of commodities and the operation and design of electricity consumption and production units are of interest. Parameters related to the flexibility of the steel industry, transport costs for iron commodities, benefits derived from knowledge in regions with steel production today, and freedom in relation to the localisation of the steel demand, are varied in the study. In **Paper VII**, the main parameter that is varied to understand the role of hydrogen flexibility is the size of the European hydrogen demand, which is varied within the range of 0– 2,500 TWh_{H2} in steps of 500 TWh_{H2}. Three types of flexibility from hydrogen are examined, based on: i) flexibility from hydrogen storage; ii) flexibility from localisation of the hydrogen demand; and iii) full temporal flexibility in relation to the timing of the hydrogen demand.

3.2 Temporal considerations

The temporal dimension relates to the time resolution and the temporal scope. The time resolution is concerned with the number of time-steps within the time period and whether the time-steps are consecutive or separate. The temporal scope relates to the time-span that is modelled. The time-span can stipulate whether the time starts from now and advances step-wise forward in time or jumps to a future Greenfield period with suitable assumptions being made as to costs and policies, such as carbon emissions constraints. In the case of ENODE, time is modelled as a single Greenfield year. The potential lock-in to the current power plant fleet and the transition pathway are lost in this approach. Nevertheless, the studies included here are focused on the dynamics of the interactions between generation technologies and VMS in a future, carbon-neutral electricity system, for which purpose the Greenfield approach is deemed suitable.

Four different time resolutions are applied in the appended papers: i) one-hourly; ii) three-hourly, where the value for every third hour is used as sample; iii) 12-hourly, where the time-steps are averages for the hours of 06-17 and 18-05 so as to represent a day and a night step, respectively; and iv) chronological clusters chosen with the heuristic Ward method described by Pineda and Morales (2018) [53], with the same number of time-steps as for the 12-hour resolution (i.e., 730 time-steps). Pineda and Morales have used the Ward method for merging consecutive time-steps with the smallest differences in wind power, solar power and demand profiles, so as to keep the variations at a maximum. For the work of **Paper VII**, this method results in time-steps with lengths of 5–19 hours. All four methods maintain full chronology within the year, which enables variation management to work on time-scales that range from hours up to 1 year, to match the historical load and generation levels with weather patterns for the same year. Use of the demand, wind power, and solar PV generation profiles for the same year captures the relationships between these parameters that would otherwise be difficult to estimate, such as the correlation between electricity generation from wind and solar and the temperature (which affects the electricity demand for heating).

3.3 Spatial considerations

In **Papers I–IV**, single copper-plate regions in the size of electricity price areas are modelled in isolation. This enables perfect geographical smoothing of weather variations within the available areas in the region, although it eliminates the potential benefits from trading electricity with other regions *via* existing or new transmission lines. Thus, the short-term variability within the region is under-estimated, and the variability on a time-scale of several hours, as well as the need for self-sufficiency are exaggerated. Transmission between region-pairs is modelled together with the generation and storage options in **Paper V**. Transmission is under-represented also in **Paper V**, although single regions, as well as region-pairs allow capturing of the impacts on specific systems that are suitable for wind power and/or solar PV with different underlying potentials for variation management. In **Paper V**, four investment cost levels of transmission are modelled without taking distance into account, i.e., 10 (isolation), 3, 1 and 0 M€/MW (for free), so as to capture the value and role of transmission. The correlation between wind-speed at two locations is reduced with the distance between locations. To investigate the value of the reduced correlations between wind power production and distance between locations, the relationship between wind profiles in the region-pairs were varied, to understand better the role of transmission. A case with the actual wind power production profiles for the region-pair was compared to cases with synchronised profiles (i.e., the same wind profile was used in both regions) in the region-pair, to address the value of resource transfer between regions with different resource availabilities in isolation from the value of geographical smoothing.

In **Paper VI**, the model is expanded both geographically and in terms of the commodities available for trade. In this case, Northern Europe is modelled as 12 regions that can trade electricity *via* existing or new transmission lines (at an investment cost of 1.85 k€/MW/km). In addition to trading electricity, commodities from the steel industry are included in the trade, more specifically steel and its less-refined species hot bracketed iron (HBI) and iron ore. In **Paper VI**, the steel industry is hydrogen-based and the possibility to relocate the steel production is included to evaluate the value of transporting more-or-less refined goods in need of energy-intensive processing, while retaining the possibility to transport electricity. Commodities trading is based on the weight of the goods, as well as on the distance and available transport modes in and between the modelled regions. (Including some model cases in which the cost of transportation is independent of distance, to concretise the impact of the cost of transportation.) In steel production, 1 tonne of steel originates from 1.5 tonnes of iron ore, which after reduction gives an output of 1.1 tonne of HBI. Thus, transportation costs are assumed to decline with reductions in the weight as more refined products are traded.

In **Paper VII**, the geographical scope is expanded to cover most of the EU, Norway, Switzerland and the UK, divided into 22 regions. In this paper, electricity is traded as in **Paper VI** and in one case the demand for hydrogen is freely allocated for assessing the benefits of locating the future demand close to resources suitable for low-cost hydrogen production through electrolysis.

3.4 Sectoral considerations

Considered in this work are the electricity (all papers), heating (**Paper I**), transport (**Papers II** and **VII**), and industry sectors (**Papers I**, **IV**, **VI** and **VII**). The representations vary between detailed processes and general electricity or hydrogen demands. More bottom-up studies of one sector, as in for example, **Papers II**, **IV** and **VI,** have been performed without the inclusion of other sectors. This has led to over-estimations of, for example, the benefits of flexibility, as well as available wind resources. On the other hand, it has had the benefit of capturing industry-specific details, such as which type of flexibility may be reasonable. In **Paper VII**, which uses a top-down approach, these details are exchanged for case studies regarding different types of flexibility.

The demand for electricity is modelled as the historical demand [54]. In **Paper I**, the possibility to shift 20% of the load for up to 12 hours is included as household DSM (without assigning any costs to this) [25], [55]. In **Paper I**, electric boilers are modelled as potential consumers of electricity in supplying the demand for district heating [56]. The income from heat sales is included as a lumped simplification based on the modelled price for district heating in Gothenburg for the same year as the weather data [57], [58] for both the region of central Sweden and for Hungary. This aggregated simplification renders the price more general, although it does not capture differences in the length of the seasons or differences in alternative costs between and within the regions. In **Paper VII**, electrified heating with heat pumps (for meeting the heating demand currently covered by natural gas in the UK and Germany) is added to the demand for electricity [50].

In **Paper II**, the transportation sector is modelled as 426 individual cars with individual driving patterns based on Swedish GPS driving data, up-scaled to 60% of today's car fleet [59]. The charging of the batteries is modelled as direct charging, optimised charging or the opportunity to discharge the batteries back to the grid (V2G), with the driving demand being met to the same degree in all cases. Three different battery sizes were used: small, 15 kWh; medium, 30 kWh; and large, 85 kWh. Not included is the cost of the batteries, as the size is dimensioned for the purpose of driving rather than for the purpose of the grid. Infrastructural questions were taken into account by allowing for charging at 7 kW at: all stops; stops longer than 6 h; and only at the home location. In **Paper VII**, 100% of the car fleet is assumed to be electrified, along with 60% of heavy road transport. Charging of these two modes is simplified so as to occur during the same time-step as the driving. This method utilises some parts of the variation management potential derived from optimised charging and V2G, although it is concealed within the simplified temporal resolution given that the time-steps are on average 12 h.

An industrial demand for hydrogen produced by electrolysis is modelled in different ways in four of the appended papers. Generic, exogenous demands are modelled in **Papers I** and **VII.** In **Papers IV** and **VI**, potentially flexible hydrogen and electricity consumption is assessed through modelling of electrification applying greater details of the processes for biomass gasification and steelmaking, respectively.

In **Paper I**, the industrial hydrogen demand is modelled as a 20% additional need for energy (compared to the annual demand for electricity) in the form of hydrogen, spread evenly over each hour of the year, with endogenous dimensioning and operation of electrolysis and hydrogen storage. The possibility to over-produce and store hydrogen in underground rock caverns for long-term storage with tanks, so as to cope with small fluctuations in demand, is evaluated in this work. In **Papers II–V**, the possibilities to invest in electrolysis, underground storage, and (in addition to the earlier work) fuel cells for generating electricity from the stored hydrogen are included, although without any exogenous industrial demand for hydrogen.

In **Paper IV**, the demand for hydrogen is only apparent if the gasification process can enhance biogas production by adding hydrogen to the process in a cost-efficient manner. This endogenous demand for hydrogen affects the carbon balance because the residual biogenic CO_2 in the gasification process is used for either negative emissions or enhanced biogas production (CCU).

In **Paper VI**, electrified production of hydrogen is used to produce hydrogen for reducing all the iron ore that is currently reduced in northern Europe. Thus, the annual demand for hydrogen is constant for the combined regions. However, the possibility to relocate the industry, as well as possibilities to over-dimension not only electrolysis but the entire steel industry, enable variations in hydrogen production in time and space between the scenarios.

In **Paper VII**, the hydrogen demand is increased in steps of 500 TWh_{H2} (the current level of hydrogen use in European industries) within the range of 0–2,500 TWh_{H2}, in order to capture the impact of the size of the future hydrogen demand from electrolysis. In the reference case, the demand is modelled as being evenly spread over each time-step of the year and is allocated per region based on the historical level of electricity consumption. To evaluate the values of different types of flexibility in the hydrogen demand, three other cases are modelled: i) without storage, such that that the electricity demand for electrolysis becomes a base load; ii) free temporal flexibility, i.e., the hydrogen is produced at lowest cost in time and consumed when it is produced; and iii) optimised spatial localisation of the hydrogen demand, so that hydrogen is produced in the regions that offer hydrogen at the lowest cost.

3.5 Technological considerations

The technologies used include conventional and new generation technologies, storage systems and industrial electricity-consuming units. All the technologies are associated with investment costs, as well as variable and fixed operation and maintenance costs. Thermal plants are, in addition, associated with fuel costs, CO_2 emissions from the fuel, and cycling costs and emissions from start-ups and part-load operation [60]–[62] (cycling costs are excluded in **Papers V** and **VII**). The investment costs for electricity generation, storage systems and industrial units are annualised with a discount rate of 5% and with the technical life-times used as economic life-times.

Biomass, biogas, coal and natural gas plants (open and closed cycle gas turbine plants), with and without CCS, as well as nuclear power plants are the basic (dispatchable) thermal generation options in the modelling [14]. CCS technologies are assumed to be fuelled with mixes of either coal and biomass or natural gas and biogas in **Papers I**, **II** and **V**, to enable net-zero emissions despite capture levels of around 90%. Negative emissions from bio-CCS (BECCS) as its own technology are included in **Papers III**, **IV** and **VI**, whereas neither CCS nor fossil fuels are included in **Paper VII**. Biomass is assumed to be sustainable and, for the purpose of simplification, is considered to be carbon-neutral.

In addition to thermal generation, on-shore and off-shore wind power, as well as solar power are included as options for electricity generation. The wind power, solar PV, and load profiles are representative of Year 2012. In **Papers I-VI**, the wind power production is modelled as wind farms using re-analysed data, divided into 12 on-shore classes and one off-shore class [18],[63]–[66]. Solar PV is modelled as mono-crystalline silicon cells installed at a fixed optimal tilt, with one generation profile for each region [63],[67]. In **Paper VII**, the weather-based production profiles are updated with profiles from ERA-5 using the method developed by Mattsson et al. (2021) [68], and the number of on-shore wind classes is reduced to four classes. Hydropower is modelled for the region of central Sweden, representing locally generated hydropower and hydropower imported from northern Sweden in **Papers I–IV** (with historical limits on ramp-rates in **Paper I**) [69], [70]. In **Paper VI**, Nordic hydropower is included and in **Paper VII** reservoir hydropower and run-of-the-river hydropower are included for the regions of interest. The economic data for wind power and solar PV have been updated during the work and stem from the previous reports [60], [71], [72]. Economic and technical data for variation management technologies were acquired from the Danish Energy Agency [72].

Lithium-ion and vanadium redox flow batteries were modelled in **Paper I** with fixed C-rates (the ratio of the storage to the charging potential; a C-rate of 1/2 or 1/4 describes storage systems that can be fully charged in 2 or 4 hours, respectively). The batteries in **Papers II**, **III** and **V–VII** were divided into separate investments in storage and charge/discharge capacities, representing only lithium-ion batteries. With a portion of the battery cost being assigned to the charging capacity, the model is allowed to design C-rates that are adapted to the needs of the stationary electricity system (i.e., longer endurance). For the cases investigated, this resulted in batteries with C-rates in the range of1/6–1/5. In **Paper IV**, a C-rate of around 1/6 was assumed, and the cost for this was incorporated into a single cost of battery storage.

All fuels are included exogenously, with the exception of biogas, which is assumed to be produced through the gasification of solid biomass. In **Papers I**, **II** and **V-VII**, the cost of biogas is connected to the biomass prices based on 70% conversion efficiency and an added cost of 20 €/MWh_{th} for the gasification plant [73]. In **Paper III**, the amount of biomass is limited, and the fuel is supplied for free in the model with the marginal value being set by the shadow price of the supply limitation. A more-detailed description of gasification is included to capture the possibilities for enhancing biogas production by adding hydrogen and electricity to the process [74]. Potentially conservative assumptions regarding the additional methanation process that occurs when combining CO_2 and hydrogen make this representation rather similar to the simpler assumption regarding the cost for converting biomass to biogas used in the other papers (except in **Paper IV**).

In **Paper IV**, gasification is modelled in greater detail and with higher levels of ambition regarding the usage of CO_2 and the potential for enhanced biogas production through hydrogen additions. In this paper, three configurations for post-processing of CO_2 from direct gasification (Figure 6) are examined: i) one where excess CO_2 is captured and stored (CCS) or emitted to the atmosphere (ATM); ii) one where all carbon is utilised for electro-fuel production by reaction with hydrogen produced from electrolysis (CCU); and iii) a combination of the above two configurations, with flexibility in alternating operation between the CCS and CCU modes or emitting the CO_2 to the atmosphere. If CO_2 is captured and stored (CCS), roughly 70% of the energy of the biomass is converted in energy terms to high-quality biomethane, which contains about one-third of the carbon of the input biomass. Thus, about two-thirds of the carbon is available for negative emissions through CCS, or for enhanced biomethane production in the CCU configuration. The CCU option increases the production of biomethane with almost no efficiency losses from the hydrogen input (albeit with electrical losses during hydrogen production), such that the biomethane production has the potential to triple in output. The CCU option [designs (ii) and (iii)] adds a minor cost for the additional Sabatier reactor used for the synthesis of methane, and for the combined configuration design (iii), two separation units are needed instead of one.

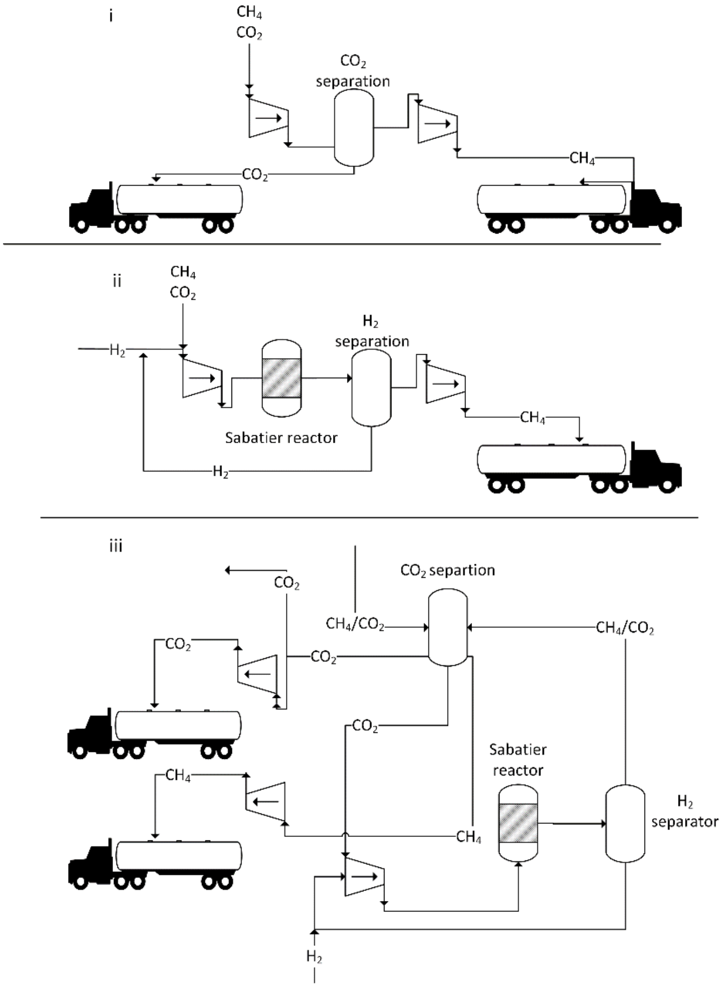

Figure 6: Simplified flow-sheets of the three considered design configurations for post-processing of excess CO2 from the biomass gasification process. Source: ***Paper IV****.*

A schematic process model for primary steelmaking, as used in **Paper VI**, is shown in Figure 7. Hydrogen is used for the reduction of iron ore to hot briquetted iron (HBI) in the hydrogen direct reduction (DR) shaft. The HBI can be stored before it is processed into steel in an electric arc furnace (EAF). Water electrolysis is assumed to be the source of hydrogen. All three processes, electrolysis, DR shaft and EAF, need electricity as an input. Therefore, it is of interest to allow the model to dimension not only the electrolysis and hydrogen storage, but also the DR shaft, HBI storage and EAF. The flexibility of the DR shaft and EAF are modelled as: i) totally inflexible, running at 100% constantly; ii) having a minimum load level of 30%; and iii) being fully flexible between 0% and 100%. The flexibility was modelled in these different ways due to uncertainties regarding the technical limitations and costs for cycling the processes.

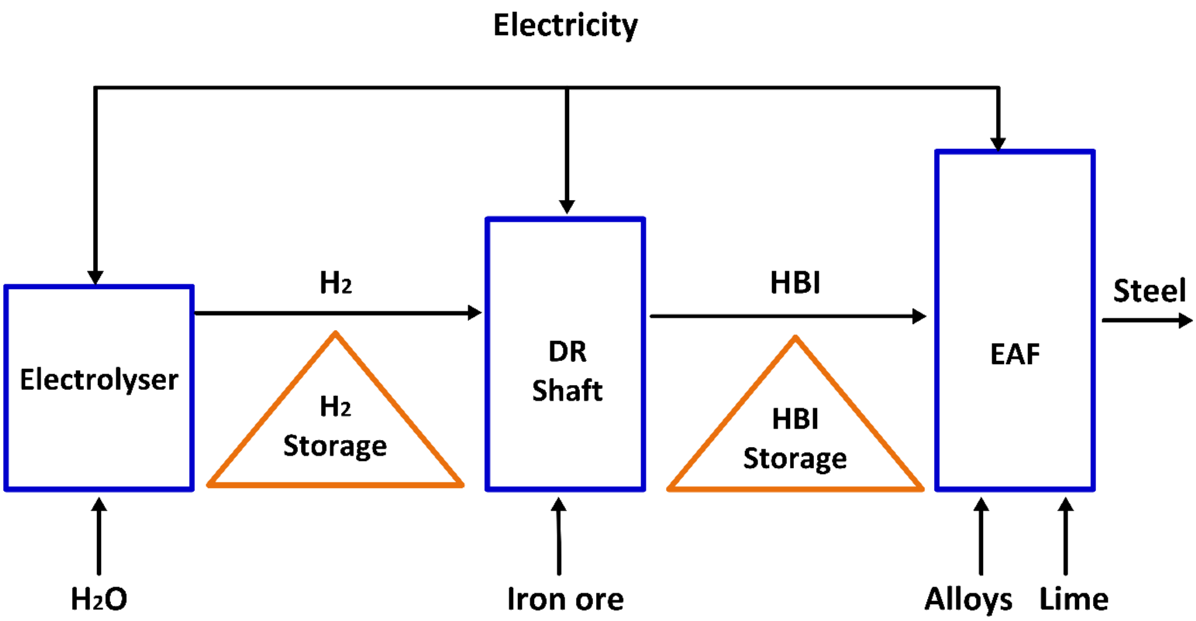

Figure 7: Schematic representation of primary steel production using the hydrogen direct reduction (H-DR) process. Hydrogen is used to reduce iron ore into hot briquetted iron (HBI) in a direct reduction (DR) shaft. The HBI is further refined to steel in an electric arc furnace (EAF). Source: ***Paper VI***.

4 Main results

In the early phase of introducing wind and solar power into electricity systems, the two technologies can be integrated into the systems without the addition of dedicated strategies to manage variations. Due to the low cost, there is a possibility to expand VRE such that some of it is curtailed and other production plants modify their operational patterns to accommodate the variations in generation. At some point, integrating wind and solar power into the system without tangible flexibility measures results in an increased cost to meet the demand for electricity despite the low cost of VRE. When integrating VRE with VMS the total cost of needs to be lower than the cost of competing generation. This is a basic rule for cost-efficiency.

The context in which VMS are needed or valuable for VRE integration is, thus, dependent upon the circumstances. The amount of additional VRE that can be cost-efficiently integrated into the electricity system with the support of variation management is dictated by: (i) whether the remaining sites for VRE generation have poor conditions for VRE generation and VRE is out-competed by base-load generation; and (ii) whether additional VRE generation is extensively curtailed and VRE out-competes itself in competition with a peak- or intermediate-load supply that has few full-load hours. The concepts of resource-limited and system-limited VRE (defined in **Paper I**) relate to these first and second states, respectively. We have found that the choice of VMS to increase the cost-optimal share of wind and solar power in an electricity system is determined by which of these two states is limiting.

At a low penetration level, the system value of installing wind power is high, as compared to the costs that it has to cover. However, the marginal value of additional investments is reduced as the penetration level increases, as shown in Figure 8. The first reduction occurs as the choice gradually tends towards poorer wind classes, concomitant with slowly increasing costs for integration. In this phase, with wind power supplying 0%–60% of the annual demand for electricity, the wind power in combination with some complementing generation replaces the base-load generation technologies. If the cost-optimal share of wind power is reached before the base load is phased out it is resource-limited. Cheaper complementing generation could, at that level, support the marginal value of wind power to supply a larger share of the generation mix. Resource-limited generation does not mean that all areas are used but that the areas that remain are un-economical without support. At a high penetration level, i.e., when wind power supplies more than around 60% of the annual electricity demand, additional investments lead to increased curtailment and, therefore, exert weaker impacts on the residual system. If the cost-optimal share of wind power is high, it is system-limited. At this stage, expanding wind power through an absorbing VMS from system expansion has the strongest effect. The level of 60% is system-dependent, as saturation can be reached earlier if other renewable sources, such as solar PV and hydropower, supply significant shares of the demand.

The marginal system value of solar PV is high when there are low levels of solar PV in the system, since it reduces the need for peak generation during the middle hours of the day. By itself, however, solar PV quickly becomes system-limited, as the generation is concentrated to a few hours. The cost-optimal share of system-limited solar PV is efficiently increased by introducing shifting VMS, such as the usage of batteries. Additional integration of system-limited combinations of solar PV and shifting strategies benefit from durable complementing and absorbing strategies to manage cloudy days or seasonal variations.

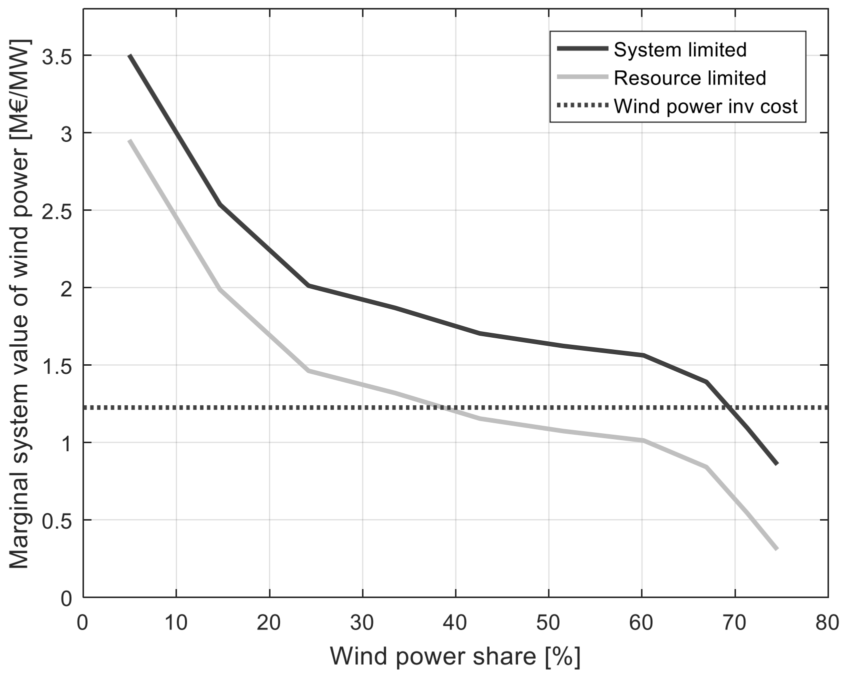

Figure 8: Explanation for the marginal system values of wind power for a resource-limited region and a system-limited region. The marginal system value represents the willingness to pay for additional wind power investments at different levels of wind integration [18]. *The point of intersection between the marginal system value and the investment cost gives the cost-optimal wind power share. The marginal system value can remain above the investment cost for a longer or shorter interval than is shown in the figure, depending on the system conditions and the availability of variation management.*

These limiting states in combination with the VMS categorisation are used to explain further the importance of VMS for VRE integration in the remainder of this chapter. The impacts on investments and operations from temporal and locational VMS are in focus in Section 4.1. The results regarding the economic value of VMS and the impacts on costs and prices are presented in Section 4.2.

4.1 Impacts of VMS on VRE integration

In general, cost-optimal investments in wind and solar power are increased as one or several VMS are added to the available technology mix. In resource-limited regions, there is a strong potential to increase the share of renewables, whereas in system-limited regions there is instead the possibility to improve utilisation of the already installed VRE capacities or to increase the VRE capacities when expanding the system to supply other sectors or regions. The strong connections between solar integration and shifting strategies, such as batteries and household DSM (as mentioned earlier), are described in **Papers I** and **II**. **Papers I** and **III** illustrate how complementing VMS, such as biogas power or reduced electricity consumption for hydrogen production, support wind power in competition with base-load generation. The roles of absorbing strategies are primarily of interest when it comes to increasing VRE in situations where there are under-utilised, good resources, i.e., in what are termed ‘system-limited’ regions. **Papers I**, **IV** and **V** show how power-to-heat, CCU and trade can facilitate the uptake of good wind resources. The possibility for variation management on a seasonal basis based on over-capacity in the steel-making industry (i.e., reducing steel production during a couple of winter months in southern Germany and Poland, as described in **Paper VI**) or hydrogen-consuming sectors in general (**Paper VII**) shows strong potential as a driver of investments in solar power. This strategy increases the value of solar PV during low-net-load periods and reduces the need for complementing generation.

When the model makes an investment it is always the most-economical choice based on the boundary constraints and input data. Therefore, the model makes the most of every opportunity. Thus, it is interesting to allow more than one VMS at a time in the model. The downsides of individual VMS, i.e., the expensive energy storage capacity in shifting strategies, the high cost of charging and/or discharging capacity in many complementing strategies, and the untimely opportunities of many absorbing strategies, can be mitigated by combining strategies from different categories. In **Paper I**, batteries, electric boilers (power-to-heat), hydrogen storage, low-cost biomass (30 €/ MWh_{th}, reduced from 40 €/ MWh_{th}), and household DSM (20% of demand delayed for up to 12 hours) were added one-by-one, as well as all together (*Full Flex*). The results illustrate how short-term storage units can shift the load and generation to less-intense, net-load events that are better suited to the complementing and absorbing strategies. Shifting strategies, for example, reduce the need for expensive electrolyser capacity, which is required for industrial electrification. For the two resource-limited regions, the capacities of wind power and solar PV are increased to a greater extent by the combination of all these strategies than by the sum of the individual strategies (Figure 9, a and b).

Wind power also benefits from the increase in solar PV, and *vice versa*, as base-load generation is pushed out of the system, as can be seen in Figure 9. When the conditions for wind or solar generation are very good, i.e., system-limited, VMS can enable wind power to expel solar PV (Figure 9, c and d) or solar PV to eliminate wind power (as in the case of large-scale V2G implementation in sunny regions, such as central Spain; **Paper II**).

This section further addresses VRE integration from the aspects of flexibility derived from bioenergy (Section 4.1.1), hydrogen (Section 4.1.2), transportation (Section 4.1.3) and trade (Section 4.1.4). Flexibility from bioenergy relates to biogas combustion, biogas production and possibilities arising from negative carbon emissions. For hydrogen, flexibility from both the production and consumption sides are assessed. For the transport sector, strategies related to flexibility derived from the charging time of private cars is examined. Finally, VRE integration aspects related to the trade of electricity or of goods produced in energy-intensive industries are studied.

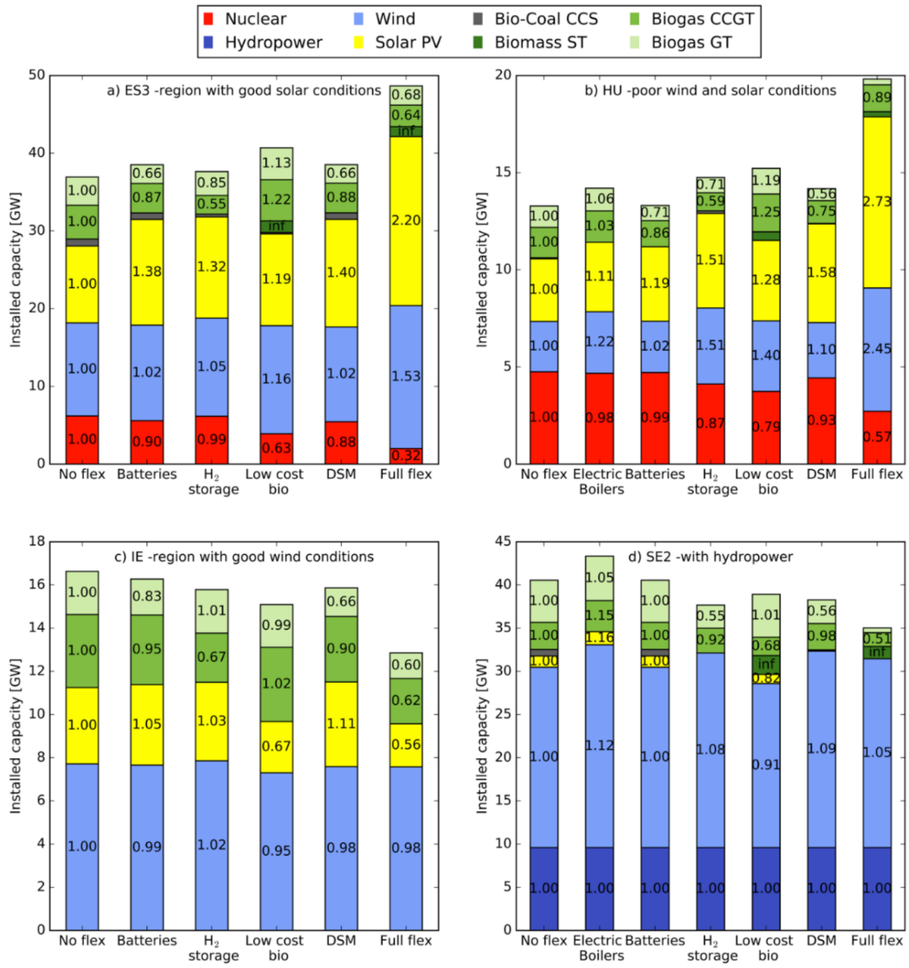

Figure 9: Installed capacities in the VMS scenarios for the four regions. The number in each box represents the share of capacity compared to the No Flex case. Thus, capacities that are not present in the No Flex case are denoted as ``inf'' (infinitely). The values for capacities <1 GW are removed to improve readability. The Full Flex case combines all the other VMS. Source: ***Paper I****.*

4.1.1 Bioenergy – gasification, flexible generation and negative emissions

Biomass and biogas, as carbon-neutral fuels, can be used for dispatchable complementing electricity generation, with the potential for negative emissions if the biogenic carbon in the fuel is sequestered. Another source of variation management arises from the properties of the biomass gasification process, which can be used to convert biomass to biogas. By absorbing low-cost electricity for hydrogen production, and thereafter reacting the hydrogen with excess CO_2 from the gasification, biogas production can be enhanced. This enhanced biogas production is also referred to as CCU or electrofuel production, and it competes with utilisation of the excess CO_2 to achieve negative emissions.

Biogas, which is derived from gasified biomass, is the main fuel used for complementing VRE in **Papers I**, **II** and **VII**, whereas in **Papers V** and **VI**, natural gas (for which the emissions are compensated by negative emissions from BECCS) is the main fuel used for complementing generation. However, as bioenergy is expected to be in short supply in the future, the cost and availability of biogenic resources for usage in the electricity sector are highly uncertain. In **Papers III** and **IV**, the availability of bioenergy is varied in the model and the usage of biogas for complementing VRE is strongly dependent upon biomass availability. In **Paper III**, biomass availability is varied within the range of 0%–100% of the electricity demand in terms of primary energy; the resulting electricity mixes are visualised in Figure 10. Along with bio-based generation, wind, solar, nuclear, and fossil fuel-based generation with CCS, batteries, and hydrogen storage systems were included in the model. With very low availability of biomass, it is expensive to maintain the hourly electricity balance for high shares of VRE. At these low levels of biomass, nuclear power is favoured to a great extent. However, since the levelised cost of VRE is expected to be (much) lower than the levelised cost of nuclear power, the biomass is utilised to provide as much complementing generation as possible to VRE. The optimal utilisation of biomass is for BECCS, and the flexibility in emissions provided by capturing biogenic CO_2 is used for flexible electricity generation based on natural gas. With higher levels of biomass availability, natural gas is replaced with biogas. The BECCS plants by themselves do not provide flexibility, primarily due to their high investment cost. The use of BECCS for achieving net-negative emissions, rather than for allowing the use of fossil fuels, could therefore replace other base-load generation in resource-limited systems, although it would compete with wind power and solar PV in system-limited regions. Therefore, negative-emissions policies imposed on the electricity sector do not result in additional flexibility for VRE integration as a side-effect, and bioenergy use for negative emissions could conflict with the need for bioenergy as a means to ensure flexibility for the integration of VRE. In regions with unusually good conditions for VRE, here represented by Ireland, 100% renewable systems (supplemented only by batteries and hydrogen storage) may be the most cost-efficient option, also in the absence of any biomass (or any hydropower). In such a case, increased biomass availability competes with the utilisation of wind power.

By increasing the operational modes of biomass-gasification with CCU and CCS, as described in **Paper IV**, there are possibilities to produce biogas for flexible electricity generation, transport fuel or materials, while achieving negative emissions and enabling an absorbing strategy through CCU. The integration of VRE from enhanced biomethane production through CCU is, however, limited and becomes saturated at biomass availability levels >10 TWh (for the specific region), as seen for the constant electricity mix in Figure 11 and the constant use of CO_2 for CCU in Figure 12. The saturation depends on the limited addition of value by the CCU. Thus, only VRE investments that have strong dual benefits, i.e., both reduce the need for complementing electricity production and increase biofuel production, are accepted. The building of storage units for hydrogen is an option also for CCU. However, the willingness to pay for hydrogen for CCU is too low to drive investments in hydrogen storage. Another un-economical option in this case is to release the CO_2 from the gasification to the atmosphere. Doing so makes economic sense only if: the levied tax or emissions permitting cost is less than the cost of transporting and storing the CO_2; carbon storage is not possible; or biogenic CO_2 is exempted from the carbon market.

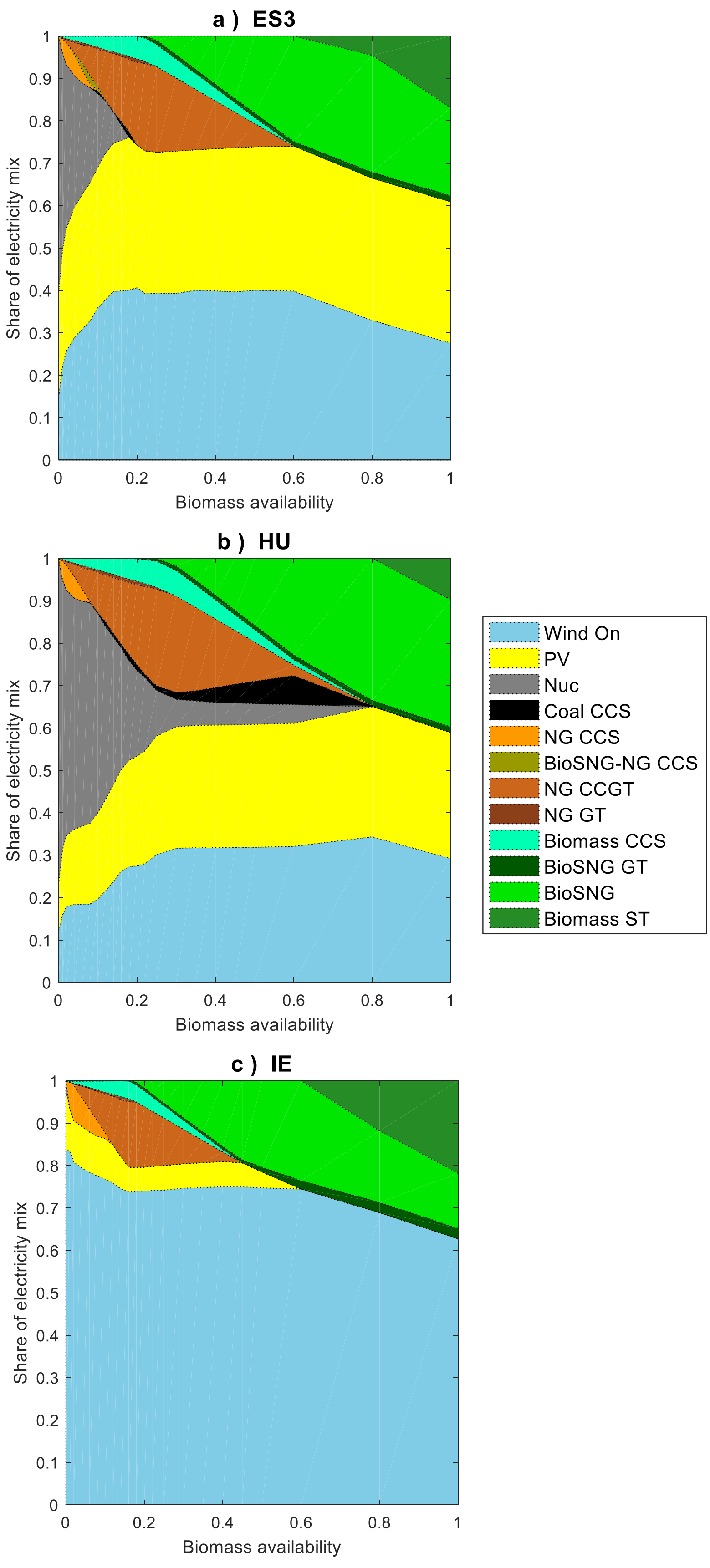

Figure 10: The electricity mixes for different levels of biomass availability in: a) central Spain (ES3); b) Hungary (HU); and c) Ireland (IE). The term 'biomass availability' refers to the primary energy in the available biomass divided by the total demand for electricity. Source: ***Paper III****.*

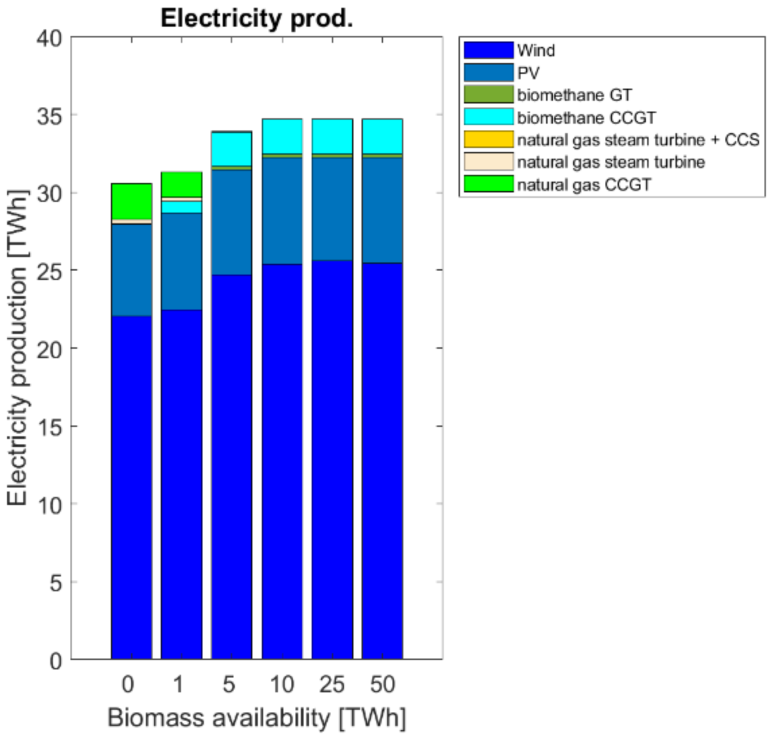

*Figure 11: Electricity mix for a future electricity system in Ireland with increasing availability of biomass for gasification. Source: **Paper IV**.*

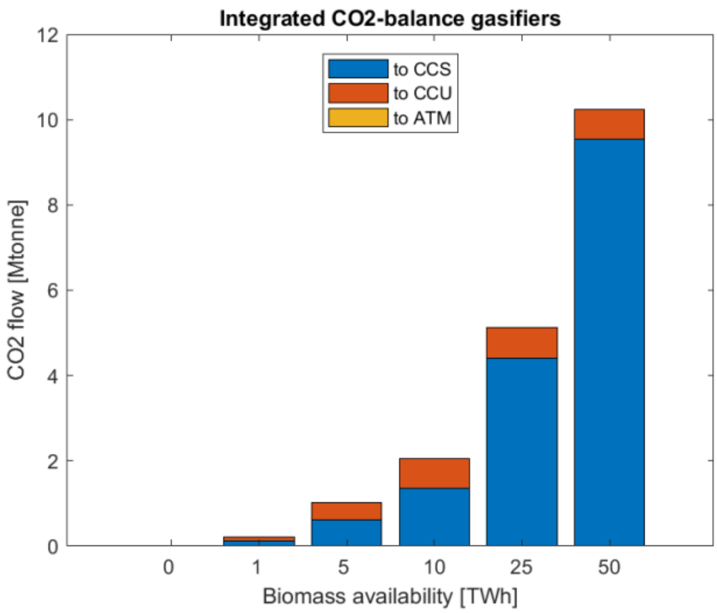

*Figure 12: Optimised usage of the excess CO_2 from biomass gasification for a future Irish electricity system with increasing availability of biomass for gasification. Source: **Paper IV**.*

In Figure 13, it is evident that CCU operates as an opportunistic absorption system for low-value electricity. As the biogas demand is set by the biogas price rather than a fixed demand, electricity consumption by the process becomes opportunistic. There are three different scenarios depending on the availability of low-cost electricity in the model: i) low electricity price – run CCU at maximum capacity; ii) high electricity price – CCS at full capacity; and iii) gasification is price-setting – run CCU at partial capacity. The electricity price set by the process depends on the alternative value of the CO_2 (for negative emissions), as well as on the alternative to using biogas, which is to use natural gas and pay for the emissions. As a consequence, the electricity cost for hydrogen production (used for CCU) has to be lower than the combination of the cost of natural gas, which for the study is set at 30 €/ MWh_{th}, and the cost of transporting and storing the CO_2 for CCS. Thus, even though the average cost of electricity consumed by the CCU needs to be lower to cover the fixed costs for electrolyser and Sabatier reactor, the maximum threshold for willingness to pay for electricity is 27 €/MWh. The operation of the gasification process could, thus, increase the interdependencies between the electricity price, natural gas price (biomass price), and CO_2 tax. A high cost for biomass increases the cost of the output and could influence decisions as to whether or not to operate the gasification plant at all. The cost of biomass does not influence the choice of operational mode (between CCS and CCU).

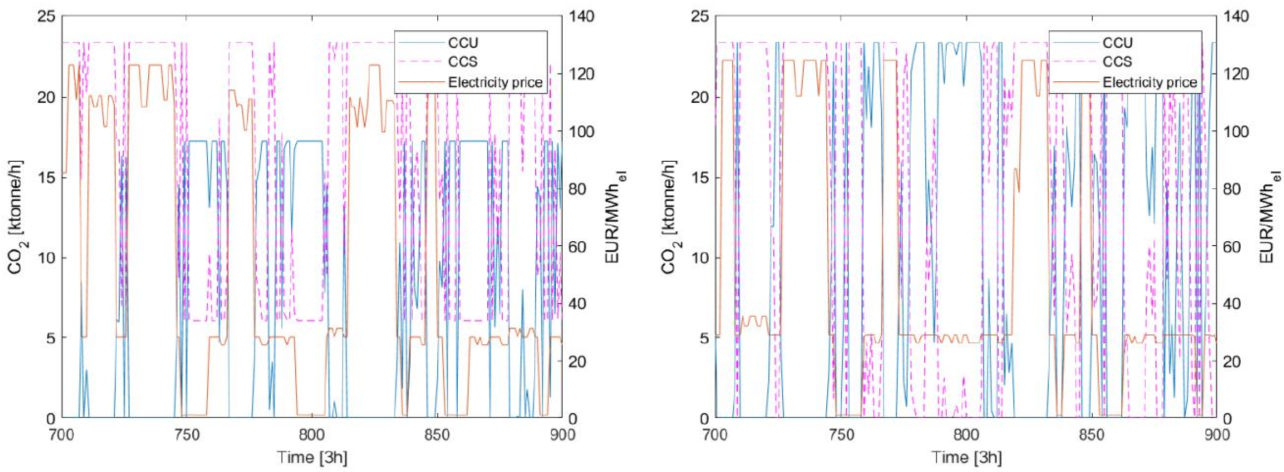

Figure 13: Operational modes of gasifiers and the marginal cost of electricity for a biomass availability of 10 TWh in the region of Ireland, under two different CO_2 taxes at 150 €/tonne (left panel) and 250 €/tonne (right panel). The CCU-related investments are saturated in the low CO_2 price case, which results in a lower maximum CCU operation and higher minimum operation of the CCS process. It is evident that the CCU process is run at part-load, as there is some low-cost electricity available (at ~27 €/MWh_{el}). Source: ***Paper IV****.*

4.1.2 Hydrogen – flexibility in relation to production and consumption

Electrification as a way to decarbonise the industrial sector is evaluated in **Papers I**, **IV**, **VI** and **VII**. In particular, the role of hydrogen production, for meeting flexible demand or to be utilised with large-scale storage, is addressed, while some potential for DSM is included for the steel-making industry. The stationarity of industries in relation to the transport sector makes industries well-suited to large-scale hydrogen storage for the purpose of avoiding peak-load electricity prices. Figure 14 shows how hydrogen storage is slowly charged, so as to be utilised during high-net-load events. As an example, from **Paper I**, to balance the supply and demand during high-net-load events for central Sweden, hydropower is first utilised to the maximum (i.e., 9.6 GW), followed by the shutting down of the electrolysers and discharging of the hydrogen storage units. The modelling results show that the cost of hydrogen storage and additional electrolyser capacity can be covered by the lower cost of electricity, as compared to inflexible hydrogen production without storage. This industry case shows how the electricity system can benefit from economically astute behaviours in other sectors.

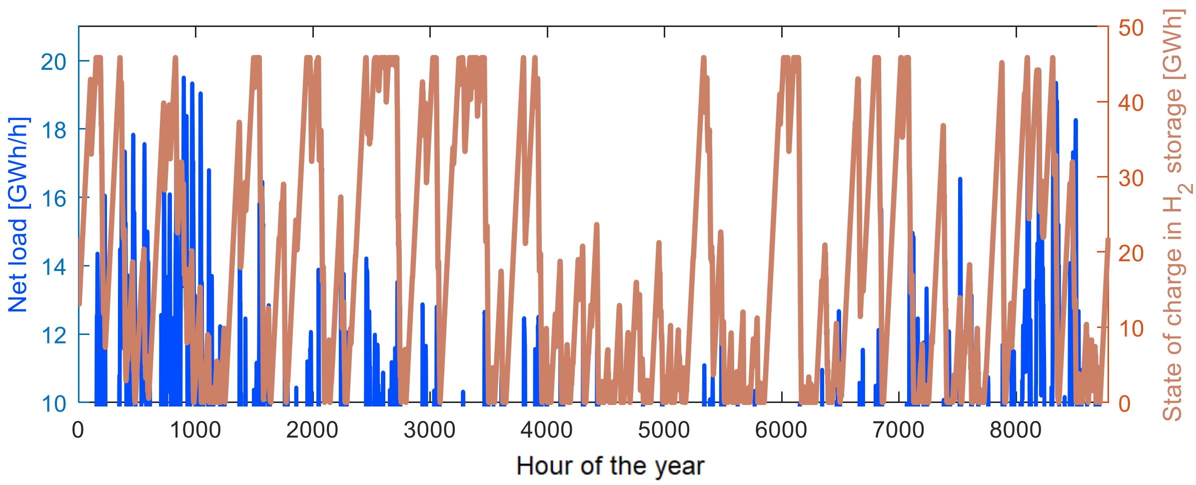

Figure 14: Operation of a hydrogen storage unit in central Sweden and a net load that exceeds 10 GW (broken left vertical axis) in the same region for the year investigated. (In the region of central Sweden, there is a hydropower capacity of 9.6 GW, given exogenously.) The hydrogen storage is subject to approximately 20 large cycles over the course of a year. Charging is slow, typically taking around 1 week, whereas discharging is faster, typically requiring 1–2 days, and is highly correlated with net-load events exceeding 10 GWh/h. Source: ***Paper I****.*

Electrification of the steel-making industry is assessed in **Paper VI**. It shows that if modelled with flexible electrolysis and EAF, i.e., including both hydrogen storage and HBI storage, hydrogen production and the equipment can be supplied mainly with wind power and some solar power, as evidenced by the "DRshaft" column in Figure 15. By allowing cost-optimal dimensioning also of the DR shaft, as is the case in the nine left-most bars in Figure 15, solar power can be integrated to a greater extent. The process flexibility also reduces the need for flexible generation from gas turbines. This is possible due to assumptions made regarding a very low cost for storing steel, such that the supply and demand is balanced over the year rather than for each time-step. The utilisation factors for the steel-making units (DR shaft and EAF) lies around 6000 FLH for these cases. Results show that assumptions on cost and flexibility of the localisation and supply chain have low impact on the share of demand supplied by VRE (first nine bars in Figure 15). The internal competition between onshore wind, offshore wind and solar power is, however, affected. Lower boundaries to locational distribution, such as low transport costs (*No_transp*) and low additional costs for introducing steel industries to new regions (*No_penalty*), result in greater utilisation of onshore wind power resources, whereas offshore wind power and solar power are needed more if the location is decided to a larger extent based on the current location of steel production plants.

We found that hydrogen production has a strong impact on the electricity system, both when hydrogen is supplied opportunistically to enhance biogas production (**Paper IV)** and when hydrogen is supplied to the steel industry (**Paper VI**). Therefore, the benefits of hydrogen flexibility on a larger scale (regarding both geographical location and timing of the hydrogen demand) are investigated in **Paper VII**. Results show that the different types of hydrogen demand flexibility are important for the utilisation of wind and solar power in the future electricity system of Europe. Since the demand for electricity will increase due to electrification of other sectors, there is a high demand for electricity already without any need for hydrogen from electrolysis. Thus, without flexibility in relation to both time and localisation, some regions start to depend on other forms of generation, such as nuclear power, early in the reference case (Figure 16). With flexibility in terms of time or localisation, this can be avoided in a cost-effective manner for meeting large demands of hydrogen (>1,500 TWh_{H2} for Europe). As for the steel-making industry, freedom in the temporal allocation of the hydrogen demand is beneficial for solar power integration, whereas hydrogen storage and freedom in relation to the localisation of the hydrogen demand is advantageous for wind power integration.

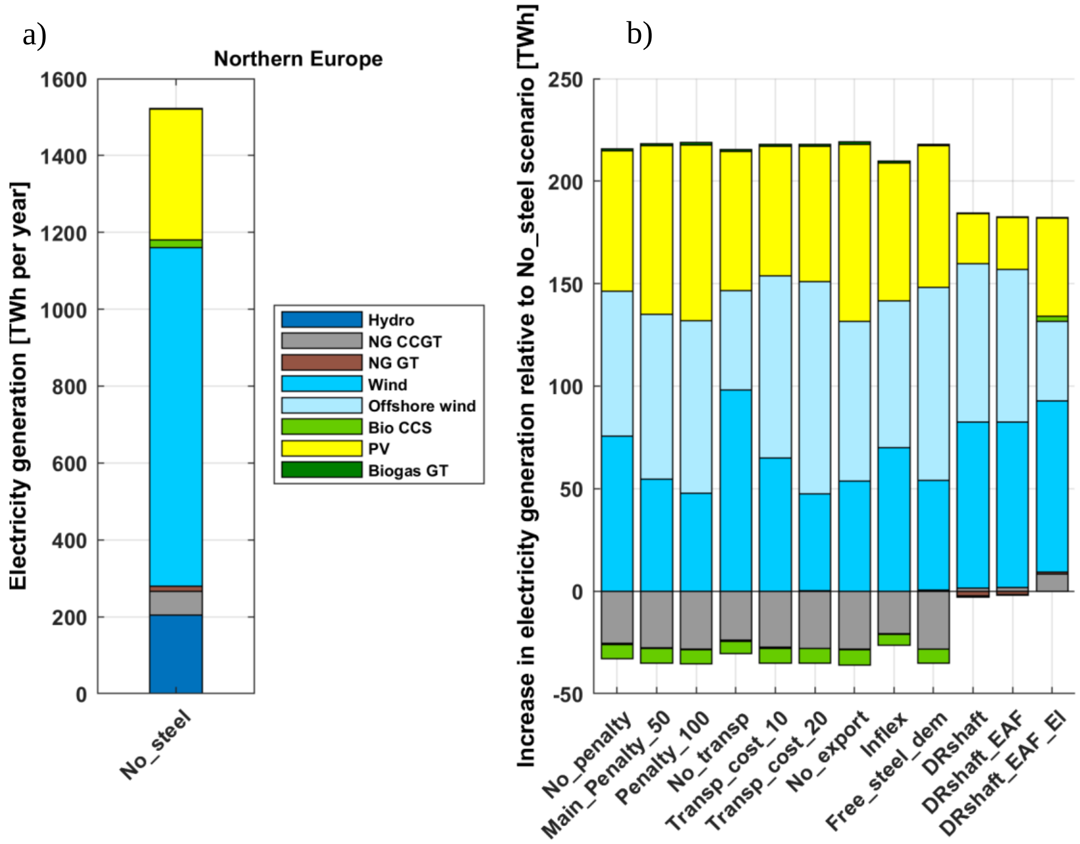

Figure 15: a): Optimised electricity-mix for a future Northern European electricity system without an electrified steel industry. b): Additions and reductions in electricity generation, as compared to the system without an electrified steel industry. The first nine bars represent cases with different costs and possibilities regarding the transportation of commodities and costs for relocating the industry. The last three bars represent cases with constant operation of DR shaft, EAF and electrolysis (El), where the case names indicate which process runs continuously. Source: ***Paper VI****.*

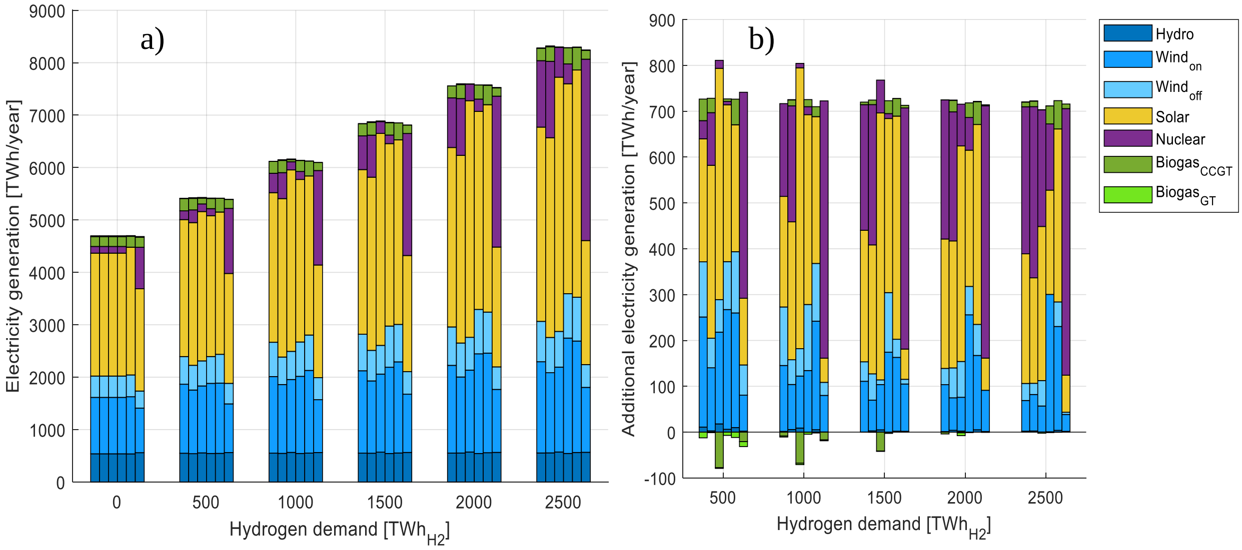

Figure 16: a): The electricity-mix for Europe in six cases depending on the demand for hydrogen. The order of the bars: Reference case; No hydrogen storage; Time – the hydrogen demand has an annual balance rather than for each time-step; Location – the location of hydrogen demand is part of the optimisation; No Nuclear; Low VRE - VRE potential reduced by 50%. b): The differences in electricity-mix from the previous levels of hydrogen demand. Source: ***Paper VII****.*

Results show that the cost-efficient electrolysis and hydrogen storage capacity increase with the demand for hydrogen (**Paper VII)**. This increase is not linear, as shown in Figure 17a. The increase is initially high since the flexibility offered by storing hydrogen stimulates a more cost-efficient VRE integration and electricity system operation. This benefit from flexibility decline as the hydrogen production becomes a larger part of the electricity system. In addition, as the demand for hydrogen increase, the access to sites with good conditions for VRE decrease and some regions invest in nuclear power which benefit less from the flexibility offered by hydrogen storage. The sizing of the electrolyser capacity, as shown in Figure 17b, depends on whether hydrogen storage is available and whether the hydrogen demand is fully flexible in time. If the hydrogen demand is fully flexible in time, the electrolysis is designed to partly follow variations in solar power generation, both regarding day-night variations and seasons.

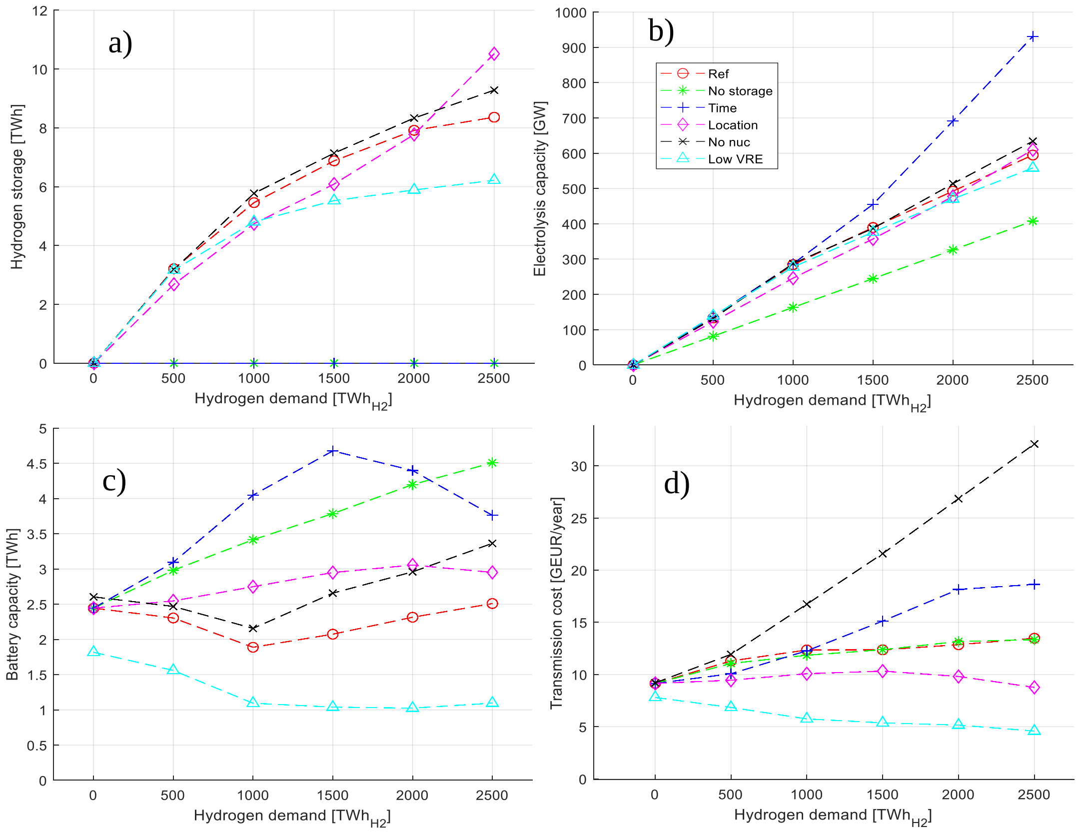

Figure 17: Optimised dimension of: (a) Total hydrogen storage; (b) Total electrolysis capacity; (c) Total battery storage capacity; (d) Total annualised spending on transmission lines between regions, for all of Europe as function of the hydrogen demand for the following cases: Ref – Reference case; No storage – No hydrogen storage; Time – the hydrogen demand has an annual balance rather than for each time-step; Location – the location of the hydrogen demand is part of the optimisation; No nuc – No nuclear power; Low VRE –VRE potential reduced by 50%. Source: ***Paper VII****.*

4.1.3 Electric vehicles – flexibility from strategic charging

Adding dedicated units, such as batteries and gas turbines, to the electricity system may not be the most cost-efficient way to balance the supply and demand in the future electricity system. Options for electricity storage are built-in when electrifying the transportation sector. The direct reduction of both local and global emissions through fuel switching from fossil petroleum or diesel to (preferably, carbon-neutral) electricity is the main driver for electric cars. In electric cars, batteries represent the modern fuel tank and the size of the battery, which determines the driving range per charging cycle, is dimensioned based on cost, weight and available space, as well as the desire for personal freedom. In **Paper II**, individual cars up-scaled to 60% of today's car fleet are modelled with three different battery sizes and with the opportunity to discharge the batteries back to the grid (V2G). The cars not only avoid charging during peak hours, but also supply electricity during these peaks by discharging electricity back to the grid. Figure 18, a and c, shows the states of charge for stationary storage units and for cars with V2G, respectively. As illustrated, the optimised storage patterns of stationary batteries and 15-kWh car batteries are of similar size. The daily charging of the car batteries needs to be more-intensive than that for stationary batteries, to satisfy also the driving demand. If larger batteries (85 kWh) become standard, the state of charge patterns for electric vehicles could also mimic the pattern of long-term hydrogen storage (Figure 18, b and d). With full-scale smart charging and V2G, stationary batteries become redundant, while the long-term storage systems can be replaced only to a certain extent. Smart charging of electric cars and V2G make it possible to expand generation from VRE already during the transition from the current system and may, thereby, promote a faster transition of the electricity system [50].

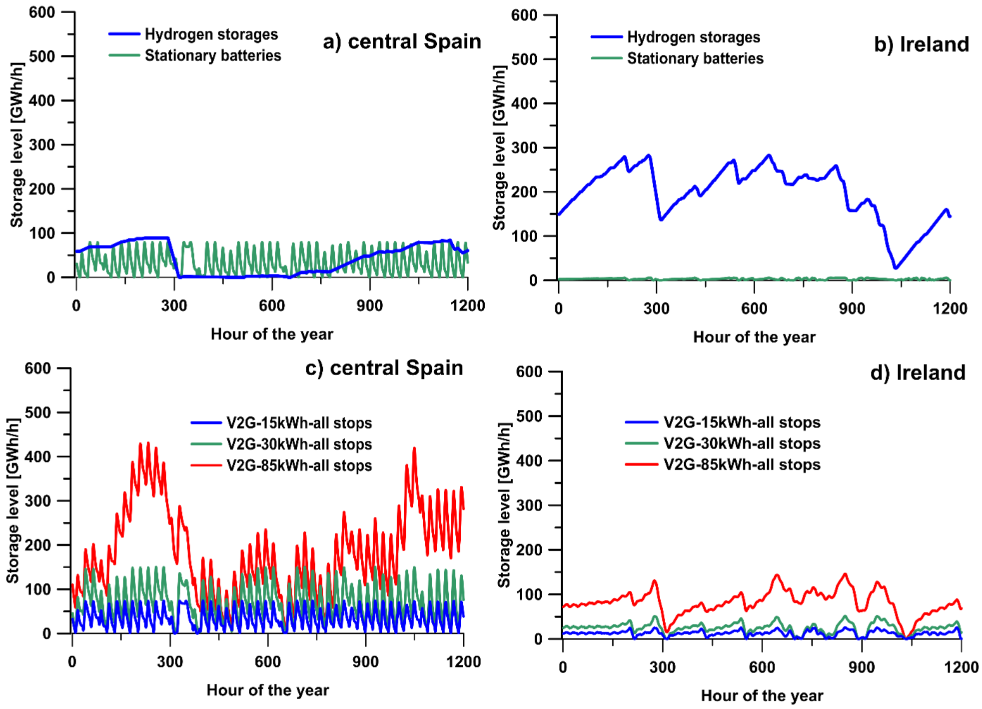

Figure 18: Storage levels of hydrogen and stationary batteries in the case with direct charging of EVs at all stops longer than 1 hour and with a battery capacity of 30 kWh for: (a) central Spain; and (b) Ireland. Also shown are the storage levels of EV batteries in a model run with V2G, assuming charging at all stops longer than 1 hour and battery capacities of 15, 30 and 85 kWh for: (c) central Spain; and (d) Ireland. Source: ***Paper II****.*

4.1.4 Trade – location of future generation and demand for electricity

Both trade of electricity, trade of energy intensive commodities and localization of future industrial hydrogen demand are considered in this work. Thus, trading electricity can be exchanged for relocating the demand, such that energy-intensive commodities, such as steel, are produced in regions with a large potential for low-cost electricity.

When assessing the role of trade in **Paper V**, two regions were paired based on the possibility to invest in transmission for a low or a high cost (1 M€/MW or 3 M€/MW, independent of distance for the sake of simplification). With expensive transmission capacity, the trade is more even over the year, whereas low-cost transmission results in more unidirectional trade. Figure 19 gives the accumulated net-export from HU to IE, i.e., the state of charge if the trading region had been a storage option. All of the cases result in one over-arching cycle (with almost-sinusoidal shape), which for some cases ends with a large negative surplus (i.e., region IE is a net-exporting region). The figure illustrates the behaviour of trade as a long-term VMS that does not require a storage capacity over which it has to maintain an energy balance. Trade provides high-wind regions with the opportunity to expand the wind share even further, so as to facilitate net-export. This can create co-benefits for solar investments, as the importing region gets the opportunity to export electricity back during summertime when European wind power is usually generating less electricity [75].

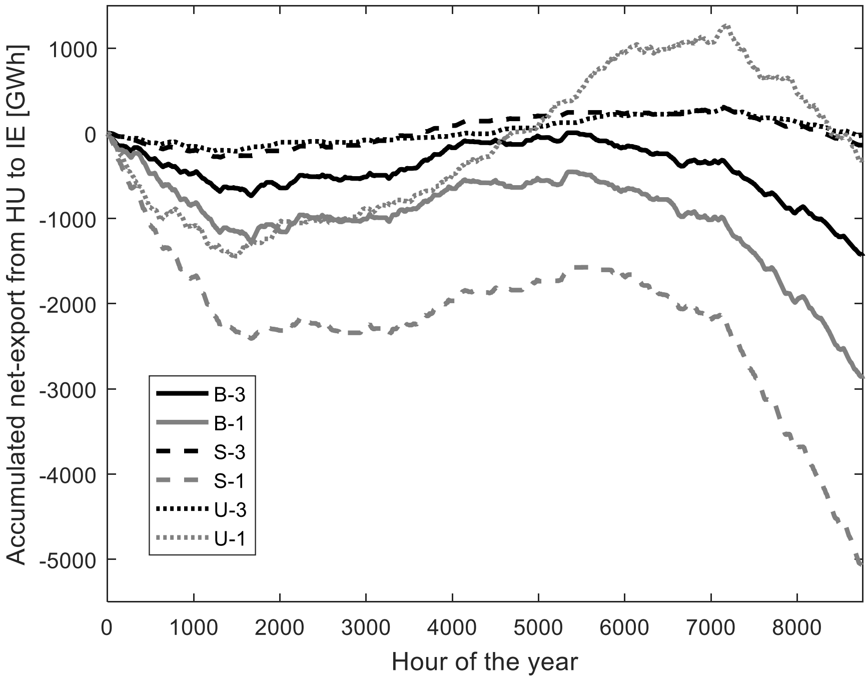

Figure 19: Accumulated trade from the net-importing region Hungary (HU) to the net-exporting region Ireland (IE). A negative end-value indicates that IE has exported more to HU than it has imported. The letters B (base case), S (stable synchronised), and U (unstable synchronised) represent the wind profile cases, while 1 and 3 represent the investment costs of transmission in M€/MW. Source: ***Paper V****.*

The demand for hydrogen and direct electricity for the steel industry can have a potent impact on regional electricity generation and trade. For example, the level of generation in northern Germany (DE_N) varies in the range of 240–300 TWh and the demand varies from 270 TWh to 360 TWh in the most extreme cases of **Paper VI** (see Figure 20). Trading of energy-intensive commodities reduces the need for electricity transmission and enables the utilisation of low-cost electricity in system-limited regions. It may also alter the annual electricity balance, as some regions can go from being exporters to importers and *vice versa*. Results show that a low cost for transporting energy intensive commodities can have a large impact on where the iron is refined (cf., Figure 21, a and c). In the case without any cost for transport of the commodities, regions that require large amounts of steel, such as northern and southern Germany and England, increasingly import HBI and steel from Ireland, Scotland, northern Sweden, the Baltic countries and southern Poland, rather than refining it domestically. Similarly, re-location of the generic demand for hydrogen in **Paper VII** promotes hydrogen consumption in regions in the north and south of Europe, for different reasons. The northern regions are attractive due to large unused wind power resources and the southern regions are attractive because they provide the best solar power resources in Europe.

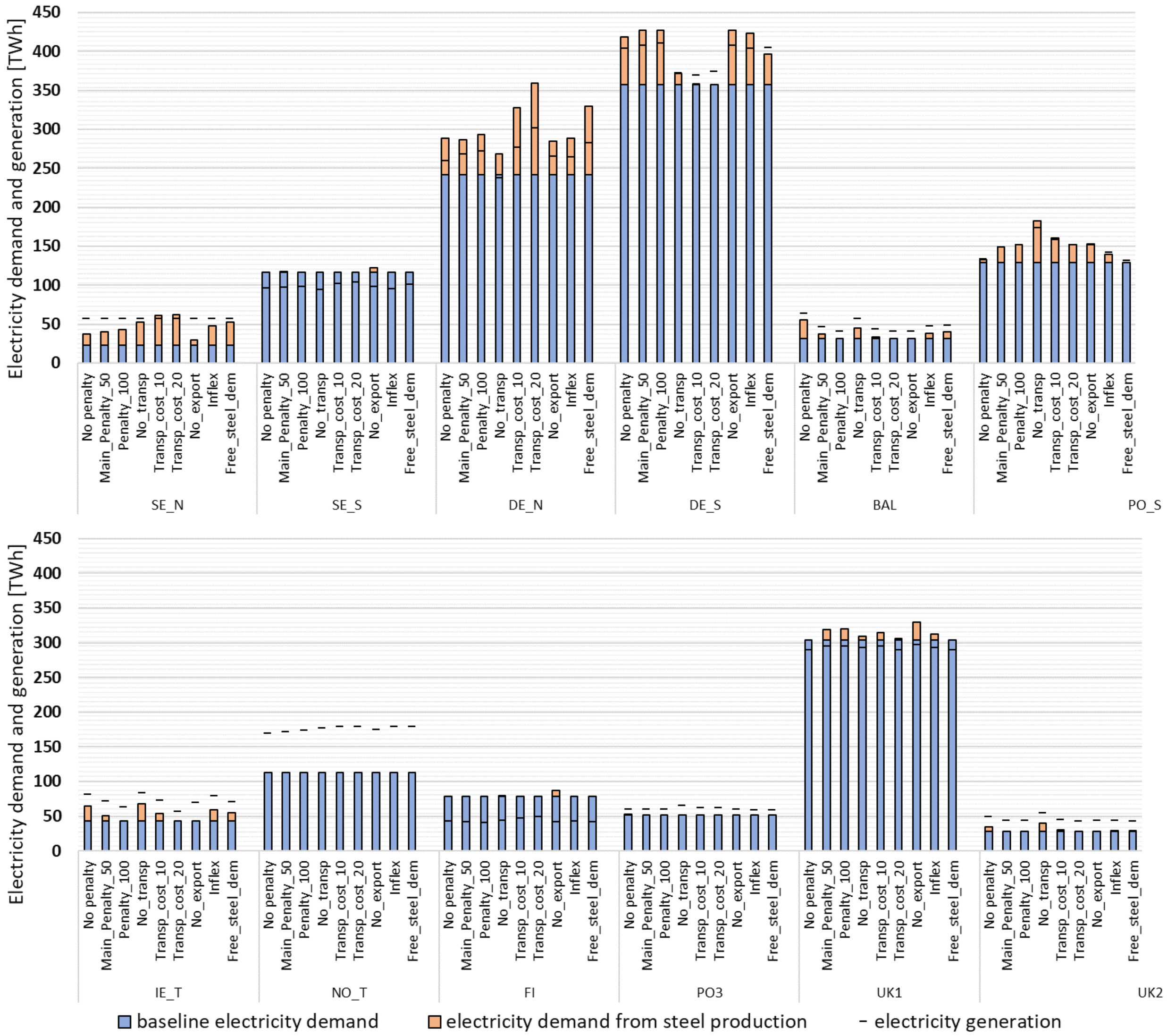

Figure 20: Total levels of annual generation, baseline electricity demand, and electricity demand for steel production for the modelled regions of Northern Europe, depending on the assumptions made regarding the cost of relocating the steel industry and commodities trading. Source: ***Paper VI****.*

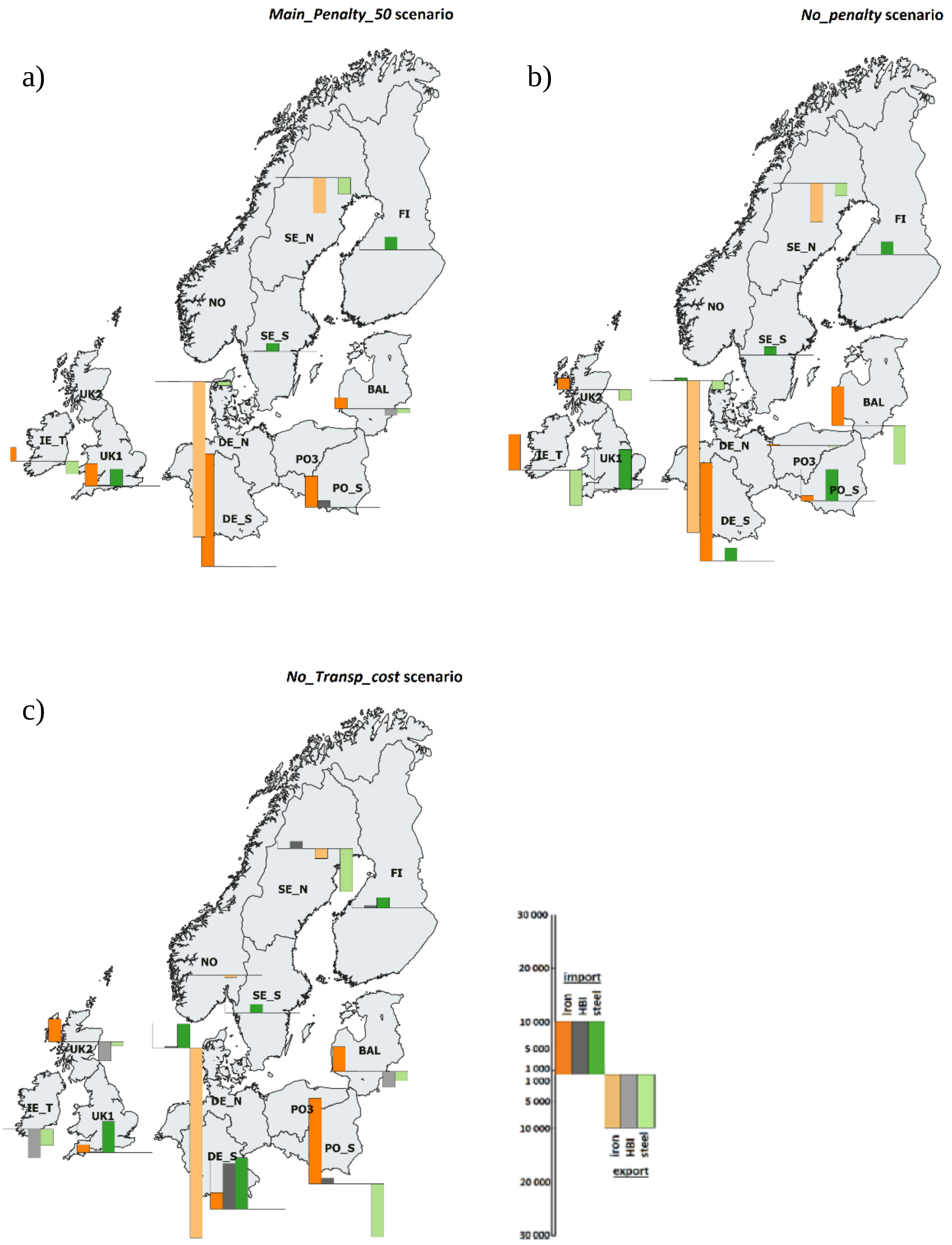

Figure 21: Levels of imports and exports of iron ore, HBI and steel for: a) the reference case, which includes distance-dependent transport costs and an investment cost-penalty for regions that have no steel-making industry today; b) without the investment cost-penalty; and c) without transport cost for commodities. Source: ***Paper VI****.*

4.2 Value of variation management

The economic value of VMS can be measured using a range of indicators such as reduction in system cost (or system cost savings), the value of complements to VRE such as biomass as well as the cost of production of electricity intensive products like steel or hydrogen. A VMS is assigned a value if it has an economic impact on the electricity system. If a technology is too expensive to be part of the cost-optimal system composition, it is regarded as worthless according to the method applied in this work. Generally, access to lower-cost VMS has a positive impact on the integration of VRE, although it may also reduce the share of VRE. Therefore, the only certainty is that lower-cost VMS results in a lower-cost system.

According to **Paper I**, VMS reduce the total system costs and the VRE share is increased in most of the cases (Figure 22). In central Sweden, which already has a large fraction of built-in flexibility from hydropower, the system cost savings from VMS in the case with all VMS (*Full Flex* case) are about 8% compared to the case without additional VMS (No Flex case). The cost savings are as high as 17% in Ireland, due to the reduced need for investments in generation capacities as VMS are made available. The cost savings are mostly derived from hydrogen storage, DSM, and the usage of low-cost biomass, with the latter two VMS being provided for free to the model (i.e., DSM and biomass rebated from 40 €/MWh$_{th}$ to 30 €/MWh$_{th}$). The use of batteries generates rather large cost savings in central Spain, but only minor savings in the other regions. The electric boilers have a weak impact on reducing the total cost, and also showed weak impacts on increasing the share of VRE in the two systems in which electric boilers where relevant.

In **Paper II**, the benefit of increasing in a step-wise manner the number of cars that take part in V2G is analysed in relation to the number of participants and the specific region. As shown in Figure 23, the marginal value of V2G participation declines from the initial value, being limited by the annualised investment cost of stationary batteries that are replaced by V2G. As all stationary batteries are replaced, the additional car batteries are used more sporadically for V2G, since longer variations demand a longer duration of storage. Nevertheless, some long-term hydrogen storage can be replaced, thereby maintaining the value above zero until most of the fleet participate in the V2G strategy. This similarity to stationary batteries, together with strategies for smart charging to meet the driving demand mean that electric cars have the potential to act as a shifting strategy with some absorbing features. The total system savings compared to direct charging is in the range of 4%–11% for optimised charging and 8%–33% for V2G for the four regions with medium-sized batteries, assuming that there is no cost for the strategies; these savings are as large as or larger than the savings derived from combining all the VMS in **Paper I**. The savings obtained in solar-dominated central Spain are about double those obtained in wind-dominated Ireland and four-fold higher than those obtained in Sweden, due to the already existing flexibility from hydropower in the latter.

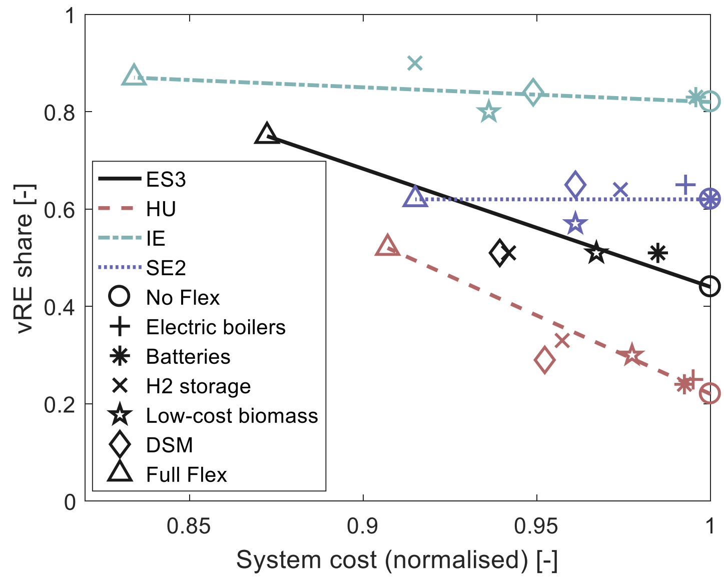

Figure 22: The VRE shares and system costs (normalised to the cost for the No Flex case) for the different VMS cases and different regions. Note that the vertical axis and the horizontal axis represent results, whereas the inputs are indicated by the different shapes. The No Flex and the Full Flex cases represent the case without VMS and with all VMS combined, respectively, and are connected by the lines, while the other cases have only the VMS stated in the name in the legend. Note the broken horizontal axis. Source: ***Paper I****.*

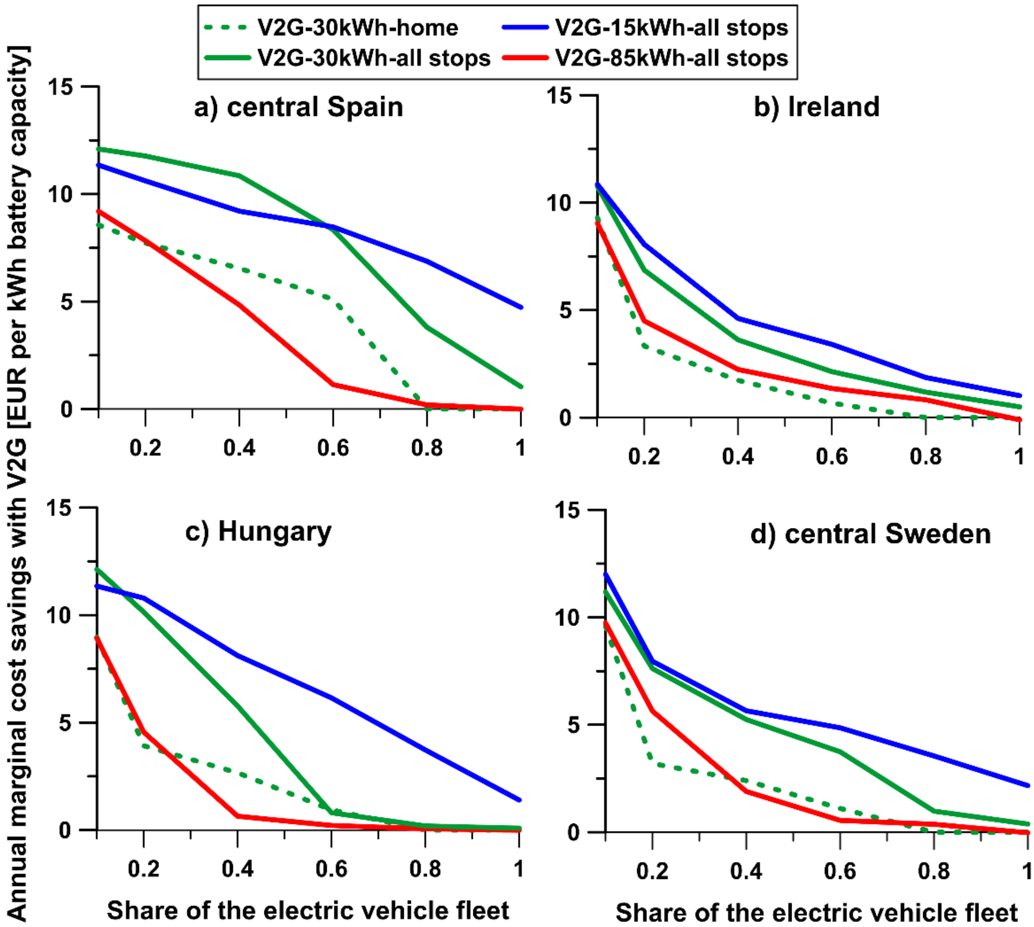

Figure 23: Annual marginal cost savings with V2G in €/kWh of battery capacity in relation to the share of the electric vehicle fleet that is participating in V2G, for different battery sizes (15, 30 and 85 kWh), regions, and charging infrastructures (i.e., charging at all stops or at home location). Source: ***Paper III****.*

The issues of uncertain supply of bioenergy and how best to utilise it when it is scarce are addressed in **Paper III**. The system value of biomass relative to biomass availability is shown in Figure 24. A similar overall trend is seen for all the scenarios and regions: a high initial value that drops rapidly until it reaches 0.15–0.25 MWh_{th}/MWh_{demand} (enough to cover about 5%–10% of the electricity demand), after which it declines slowly. In the base cases, the biomass value is in the range of 150–180 €/ MWh_{th} at 0.01 MWh_{th}/MWh_{demand}, whereby the supply is not sufficient to cover rare high-net-load peaks. These are followed by an intermediate value of about 30–80 €/ MWh_{th} where durable intermediate-net-load events are to be matched. The decline in value is slower without CCS, as more biomass is needed to supply the requirement for complementing generation if biomass cannot be combined with fossil fuels, in a situation where the negative emissions from BECCS match the fossil emissions. The value of biomass stabilises in the range of 20–30 €/MWh_{th}, and is achieved through competition with investments in wind power and solar PV. A relatively low cost for biomass would support the integration of VRE, whereas an excessively low cost would result in the opposite and would be a sign of a superfluously large out-take of biomass.

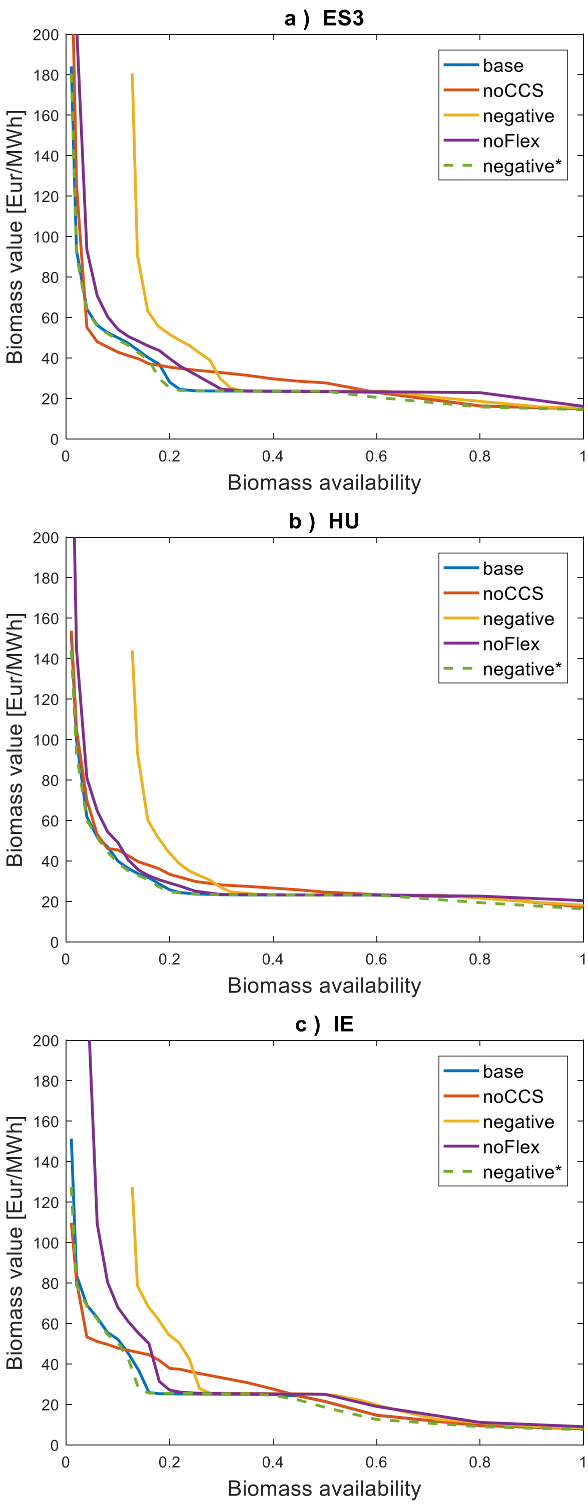

Figure 24: Biomass values for different biomass availability levels for the four scenarios. In the "noCCS" case, CCS is not allowed; in the "negative" case, there is a need for 10% negative emissions; and in the "noFlex" case, energy storage units are not allowed. The green, dashed line represents the "negative" case, where the biomass needed for negative emissions is excluded from the availability, i.e., the (yellow) curve is shifted to start at zero biomass availability. Source:* ***Paper III****.*

In **Paper V**, transmission of electricity at different costs is addressed, to capture the value of transmission between the trading regions. Figure 25 shows the relative system cost savings for different costs of transmission. The savings are largest for those cases in which trade enables both resource transfer and geographical smoothing between regions, where one region has good wind conditions (black and red solid lines in Figure 25). Resource transfer, together with geographical smoothing reduce the cost by: 5%–7% when there is access to transmission at 3 M€/MW; and by 9%–12% when the transmission cost is 1 M€/MW, where the higher end of the range relates to those cases that connect regions that are located farther apart (black lines compared to red lines in Figure 25). For comparison, the cost is reduced by only about 1.5% when connecting two low-wind regions (blue/teal lines in Figure 25). By removing the differences in the wind profile (dashed and dotted lines in Figure 25), the system benefit of resource transfer alone is 0.2%–2% of the total system cost for a transmission cost of 3 M€/MW. This indicates that a large fraction of the value of trade is attributable to geographical smoothing. At a transmission cost of 1 M€/MW, however, resource transfer can reduce the total system cost by 3%–8%. Thus, resource transfer by itself has a significant impact on the total system cost when there is a low cost for transmission. When the trading regions have synchronised wind profiles, sharing the more stable profile from the region with good wind conditions gives a total system cost that is 5%–9% lower than if the unstable profile from the low-wind region is used. This indicates that there is a smoothing element also to resource transfer.

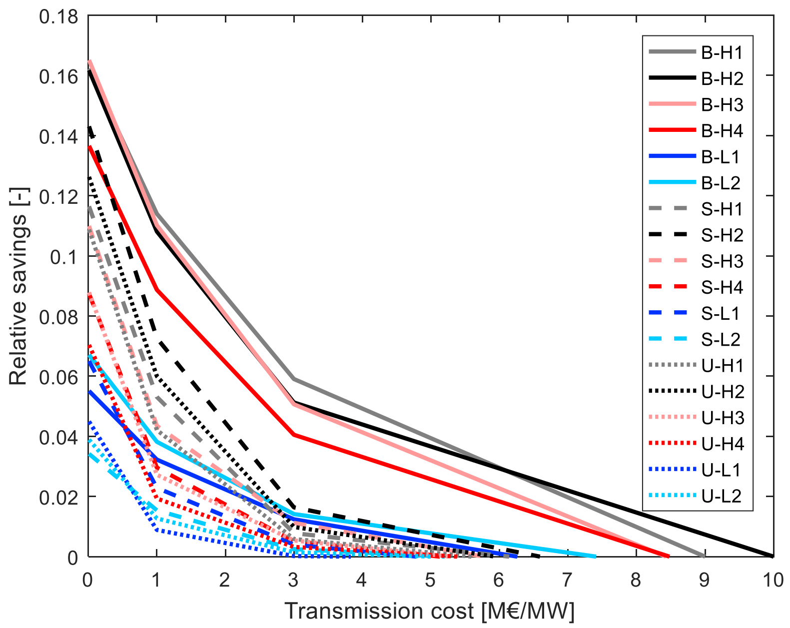

Figure 25: The system cost savings relative to the cost without any trade. The solid, dashed, and dotted lines represent the different wind profile cases. The transmission cost at which the value starts is set by the marginal value of transmission for the runs with 10 M€/MW. The letters B (base case), S (stable synchronised), and U (unstable synchronised) represent the wind profile cases. H1-H4 and L1-L4 represent the trading region pairs, where H means that one of the two regions has good wind conditions and L means that both regions have poor wind conditions. Source: ***Paper V****.*

When considering hydrogen production for industry, a flexible hydrogen production enabled by overinvestments in industrial processes and storages reduce the cost of electricity such that additional investment costs can be covered.. This can be seen in Figure 26 when comparing the *DRshaft_EAF_Electrolyser*, *DRshaft_EAF* and *Main_Penalty_50* cases from **Paper VI**. The *DRshaft_EAF_Electrolyser* case gives the lowest investment cost, as it assumes that the entire industry is designed to run continuously at maximum capacity. In the *DRshaft_EAF* case, only the electrolysis can be run flexibly by building and utilising a hydrogen storage system that satisfies a constant demand for hydrogen. In the *Main_Penalty_50* case, also flexible operations of EAF and DRshaft are enabled and are thus also optimised. The annual investments increase, but this is compensated for by a reduced cost of electricity, resulting in the lowest cost of steel of these three cases.

The three cases of *No_Transp_cost*, *Transp_cost_10* and *Transp_cost_20* in **Paper VI** (Figure 26) show that if the cost of transporting commodities is high, then the electricity price becomes less of a driving factor for localisation. If the transport cost is low, larger penalties can be taken for moving part of the industry to regions where there is no steel industry today, to take advantage of low electricity prices in regions with good conditions for VRE.

The value of flexibility regarding hydrogen production and demand is further analysed in **Paper VII**, with fewer details of the sectors demanding hydrogen but including an expanded geographical scope and a larger scope of hydrogen demand levels. The green (no flexibility), red (with hydrogen storage), pink (free geographical location and hydrogen storage), and blue (free temporal demand of hydrogen over the year) dashed lines in Figure 27 show that the cost of large-scale hydrogen production in Europe is lower for cases with higher flexibility. The lowest cost for hydrogen is noted when the demand is freely allocated in time, such that solar power can be more easily utilised without being penalised by the seasonal variation. With flexibility in geographical location, it is possible to utilise remote areas for wind installations and to choose the best solar power sites first. The difference in hydrogen production cost between all the cases representing different degrees of flexibility lessens with the size of the hydrogen demand. This diminishing value of flexibility is due to: i) the reduced cost-competitiveness of the remaining VRE, which renders a lower benefit of integration; and ii) the fact that the possibilities to achieve a more cost-efficient operation by introducing more flexibility reduce with the size of the hydrogen demand. Still, even with a very large demand for hydrogen at 2,500 TWh_{H2}, there remains a residual value in all of the addressed aspects of flexibility.

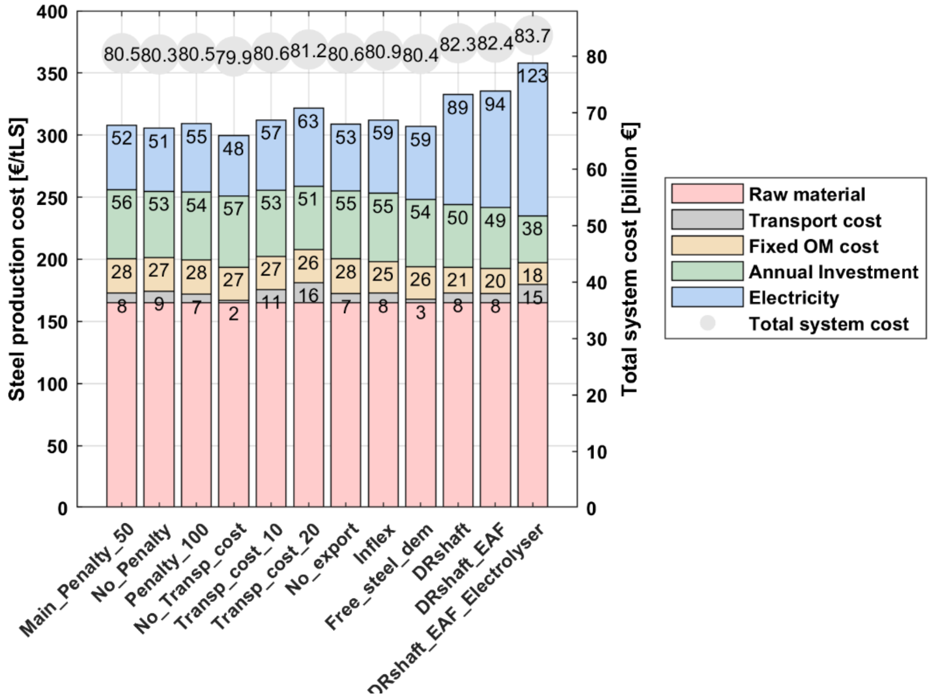

Figure 26: Breakdown of the modelled steel production cost into the raw material costs, the annualised investment cost, the fixed O&M costs, electricity cost, and transportation costs (left-hand axis). The total system costs are shown (right-hand axis) for the investigated scenarios. The modelling results include scenarios in which the minimum investment level is applied for the different steel production capacities: in the DRshaft_EAF_Electrolyser scenario, all the steel production units operate at full capacity during all hours of the year; in the DRshaft_EAF scenario, the DR shaft furnace and EAF operate at full capacity for all hours of the year; in the DRshaft scenario, the DR shaft furnace operates at full capacity for all hours of the year. Source: ***Paper VI****.*

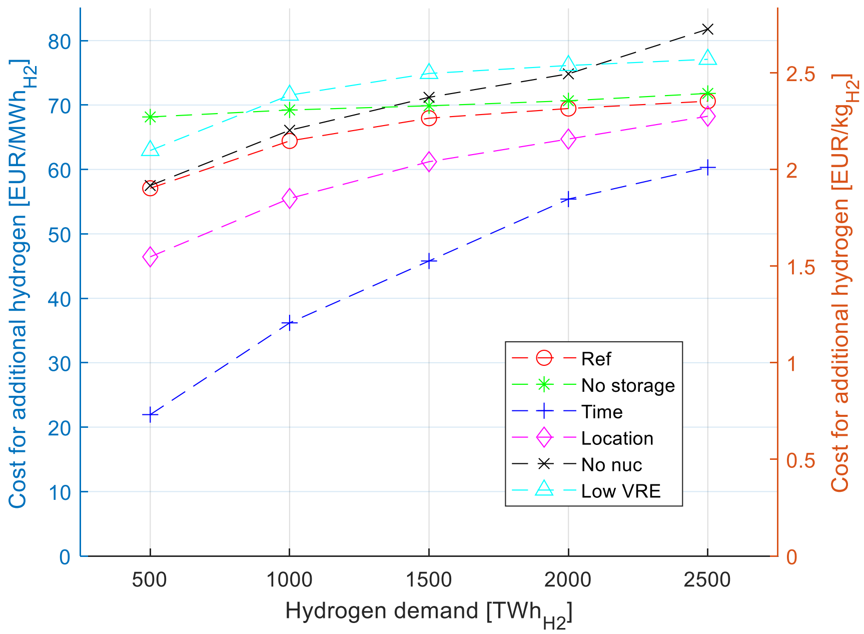

Figure 27: The costs for hydrogen for the different cases and hydrogen demand levels (calculated by taking the increase in total system cost compared to the cost in the previous hydrogen demand level and dividing it by the additional hydrogen demand). The two axes show different units for the cost of hydrogen. Source: ***Paper VII****.*

5 Discussion, conclusions and future work

5.1 Discussion

In this work wind and solar power, supplemented by existing hydropower are the weather-based renewable energy sources that together with bio-fuelled, fossil-fuelled, and nuclear-powered generation and storage technologies are optimised to meet the time-resolved demand at the lowest cost. The design of the demand side is also optimised in some of the appended work, including investment options providing demand-side flexibility. This method applied gives the lowest social cost for meeting the demand for electricity (and in some cases also heat and hydrogen). However, it would be naïve to believe that the optimal system will become reality as the world is far more complex than the rather crude model-world. In this section, some ideas are presented regarding the choices of methods and boundaries, as well as on the methodological deviations between the appended papers, and further interpretations of the results are made in a larger context.

5.1.1 Modelling dimensions

The top-down approach used in **Paper VII** reveals diminishing values for the flexibility and availability of VRE as the system grows, although industrial nuances are lost compared to the bottom-up approach used in, for example, **Paper VI**. As knowledge regarding the electrification of different sectors increases, the possibility to model multiple sectors with a level of detail that suits the addressed research question increases. This will facilitate studies that better reflect the future electricity system in which new demands will arise and grow.

Modelling sectors that include the option to optimise the choice between electrification and, for example, biofuels could provide guidance as to how to utilise resources in a better way when all sectors compete for the low-hanging energy carriers. On the one hand, this type of model with more options could enable better ordering of those VMS that in competition could take on specific roles. On the other hand, development of a wider mix of VMS than the obvious winners from the economic perspective may be of importance since there may be barriers to a large-scale expansion of these low-cost VMS, in which case redundancy in development is important.

5.1.2 Limitation of VRE growth

The limitations on VRE expansion imposed by social acceptance have economic consequences. A high cost for energy, e.g., as a result of low levels of acceptance, reduces the cost-competitiveness of European industries and entails a higher cost for comfortable living. However, speeding up the permitting processes for VRE also carry a social cost and may have negative effects on public trust in democracy. As discussed by Cherp et al. [76], the integration of VRE has to be in line with or faster than what has been done in any specific country so far to meet the 1.5°C or 2°C targets. Cherp et al. [76] have cited social resistance, geophysical limitations, and poor system integration as factors that lead to the stalling of VRE integration prior to market saturation. Many of the strategies for managing variations that are assessed in this thesis are still in their infancy or have just been initiated, so they have not yet had a positive impact on VRE integration. This delay may have resulted in early saturation and caused hesitation to start an ambitious program of VRE expansion, especially in the case of solar power, for which integration is limited without batteries or other shifting VMS.

If VRE integration is limited by land-use and NIMBY (*not in my backyard*) attitudes, there will be competition for this clean energy, resulting in a higher cost for electricity, which in turn will drive energy efficiency measures and the use of nuclear power. Energy systems with limited availability of VRE will be more expensive, although they need fewer VMS compared to high availability of VRE systems, as shown in **Paper VII**. However, if wind power is limited by acceptance issues and solar PV is not, owing to the lower visual and aural impacts of the latter, there may instead be a greater need for variation management, and in particular shifting strategies and strategies that make use of seasonal storage systems.

5.1.3 Technological cost and development

The cost and availability of technologies are key parameters for dimensioning a cost-optimal system. Technological learning and development are complex issues, and during the course of the work for this thesis the projected costs for solar PV, batteries and offshore wind power have seen major declines. For example, solar power and batteries were more expensive in the work described in **Paper I** than in the subsequent studies. As a consequence, the impact of making battery investments available is underestimated. Nevertheless, general trends regarding the VMS can to a large degree be useful even if the real-life development proceeds faster or slower than is assumed in this work. The purpose of this work was not to create a perfect picture of the future, but rather to assess the opportunities to utilise smart strategies and technologies to manage the integration of VRE.

5.1.4 Dimensioning year and perfect foresight

As in the appended papers, energy system modelling typically uses weather data for a single year as the input, where the data represent some sort of “normal year”. In recent years, multi-year modelling has been applied more frequently. Multi-year modelling studies demonstrate that: (i) benefits can be derived from collaboration mediated by transmission systems to reduce inter-annual variations [77]; (ii) wind power exhibits larger inter-annual variations than solar power [77], [78]; (iii) the choice of modelled single year can give different optimal levels of VRE, system cost, and emissions [79]; (iv) there is a greater need for long-term storage systems with lower utilisation factors, as well as more-robust results in relation to the choice of input years when modelling multiple years compared to single years [80]; and (v) operational costs may be high when the dispatch year differs from the design year [81]. The results from those studies, therefore, underline the importance of further investigations into how to handle inter-annual variations in systems that heavily rely on renewable energy sources, in order to increase the reliability and resilience of the future electricity system. Inter-annual variations have impacts on VRE integration. Still, modelling with one year gives rise to various types of variability, revealing a large part of the need for and value of the different generation and VMS technologies.

The feature of perfect foresight gives rise to high electricity prices only when it is reasonable in light of perfectly known periods of shortage for the modelled weather year. However, in reality, the marginal value of storage may be under- or over-estimated for any specific period of any year depending on the statistics and forecasts. The need to estimate a value of stored energy under uncertainty is not new but is used for managing resources like hydropower. Nonetheless, the uncertainty increases with the addition of dimensions that themselves vary, and during the transition period, changes in generation and demand for electricity will add complexity to this already difficult task.

5.1.5 Trade

Modelling the European regions in isolation results in disproportionate domestic production and variation management, as compared to modelling Europe as a whole with possibilities to collaborate for both electricity generation and balancing[24]. Thereby, the overall need for VMS in the (semi-) isolated cases described in **Papers I–V**, is exaggerated. Even though trading electricity reduces the need for VMS, the results of these papers are useful for understanding how the cost structures of the studied generation and storage technologies and industrial processes can be utilised for variation management.

Even though the geographical scope is greatly expanded in **Papers VI** and **VII**, global trade in electricity and hydrogen and the localisation of energy-intensive industries are omitted, and trade in fossil fuels and supply chains for construction materials are neglected. For example, in **Papers VI** and **VII**, re-location of industrial production is explicitly and implicitly studied as a reaction to low-cost electricity. In a study conducted by Hampp and colleagues (2021), some renewable electricity-based energy carriers are shown to be cheaper when imported to Germany from other continents, as compared to importation from neighbouring regions [82]. If energy carriers can be imported at a lower cost than domestic European production, then why should energy-intensive industries that rely on imported material be located in Europe? Before the electrification of these types of processes it will be important to determine what additional expense (justified by, for example, the security of supply) can be accepted for the local production of energy carriers and goods.

5.1.6 Fuel prices

In the end of Year 2021 and in the first half of Year 2022, the price of natural gas increased dramatically to around 70–110 €/MWh, with higher price peaks outside this range. In the appended papers, the cost of natural gas has been assumed to be 30 €/MWh. However, in most of the appended papers, a future without fossil fuels is modelled, in which the price of biogas is assumed to be around 60–80 €/MWh. However, when biomass is more costly (**Paper IV**) or in limited supply (**Paper III**), there are cases with an endogenous cost/value of biogas >100 €/MWh. Now with the increased price of natural gas, decarbonisation and the development of biomass gasification, as well as of wind and solar power integration will accelerate.

5.2 Conclusions

VMS can increase the level of cost-efficient VRE that can be integrated into the system, while reducing the cost of meeting the demand for electricity in carbon-neutral electricity systems. The choice of VMS for the integration of VRE is highly dependent upon the system context. To capture these contexts, the concepts of system-limited and resource-limited regions are defined. In resource-limited regions, remaining sites for VRE generation have poor conditions for VRE generation and VRE is out-competed by base-load generation. In system limited regions, additional VRE generation is extensively curtailed and VRE out-competes itself in competition with a peak- or intermediate-load supply that has few full-load hours. On the one hand, system-limited regions benefit from absorbing VMS to increase the utilisation of VRE and decrease the need for supplementary electricity generation. In resource-limited regions, on the other hand, complementing technologies are needed to enhance VRE production and to out-compete base-load generation technologies. Wind power integration benefits to a larger degree from strategic localisation of the demand to regions with available resources, as compared to solar power, whereas shifting strategies are mainly suited to the diurnal variations of solar PV. Batteries have a large potential to meet diurnal variations. V2G and household DSM are also suitable to manage diurnal variations. Solar power with shifting VMS suffers from seasonal variations, which can be overcome by over-dimensioning the industrial processes and seasonal storage of goods. Overall, combinations of the categories of VMS, as well as combinations of wind and solar power are shown to promote the employment of VRE, since expensive or limited storage units or capacities can be better-utilised with support from other strategies. This conclusion is based on the knowledge acquired in the studies described in the appended papers, where variation management from batteries, complementing generation, transmission, and the transport sector, as well as both general industries and specific industries for steel-making and biofuel production have been assessed. In these papers, we show that:

- Most VMS increase the potential for integration of wind power and solar PV and reduce the system cost. VMS from different categories can synergise to suppress investments in power and storage capacities to manage variability. A combination of VMS can have a stronger effect on VRE integration than the sum effect of the individual strategies.
- The integration of electric vehicles through smart charging and V2G could provide a large fraction of the flexibility needed for large-scale integration of VRE. Utilising both car batteries and the flexibility from household DSM could reduce the need for stationary batteries, while supporting the integration of solar PV. Optimised charging of electric cars together with V2G has a greater impact on system cost reduction than a combination of several other VMS.
- The need for complementing VMS for dealing with some durable high- and intermediate-net-load events is evident when the goal is to achieve high shares of VRE in a cost-efficient manner in resource-limited systems. When the supply of biomass is limited, the value of flexible generation is high. In a carbon-neutral system, the greatest amount of flexibility per unit of biomass is achieved through CCS technologies, making room for flexible, natural gas-based generation. Biomass-based generation can compete with VRE integration when there is a strong supply of biomass or when BECCS is needed to achieve net-negative emissions in the electricity sector in system-limited regions. This highlights the importance of the choice of system boundary for allocating negative emissions to the most-appropriate sites, as well as the need to identify and activate complementing strategies using sources other than those that rely on biomass.
- The results show that biomass gasifiers inter-connected with the electricity system have the potential to act as a cost-efficient VMS. The gasification design that includes options for both negative emissions and enhanced biogas production is preferable owing to its increased flexibility and potential for value creation. During high-net-load events, biogas-based electricity generation provides a flexible complement to wind and solar power. During low-net-load events, hydrogen is produced and used to increase the biogas yield together with excess CO_2 from the gasification. At all other hours, excess CO_2 from the gasification is captured and stored. Thus, the enhanced biogas production acts as an opportunistic absorbing VMS that increases the value of wind and solar power.

- Transmission allows wind power to support itself by exploiting geographical differences in wind speeds. Geographical smoothing can be achieved already with low transmission capacities, whereas a high transmission capacity handles seasonal variations from PV and wind power to a greater extent and can both transfer large wind resources and expand the wind power capacities in system-limited regions, allowing them to export electricity to resource-limited regions.
- From the modelling, it is concluded that for a steel-making industry that applies hydrogen direct reduction, low costs for hydrogen and electricity can be achieved by avoiding high-net-load events through operational flexibility of the steel production capacity, in conjunction with the storage of hydrogen and the intermediate product of ‘hot briquetted iron’, and the allocation of steel production to regions with good conditions for wind or solar generation.
- Temporal flexibility and strategic localisation of the future European demand for hydrogen may result in cost savings for hydrogen production that are larger than those accrued when applying hydrogen storage. Temporal flexibility of the hydrogen demand creates a strong potential to utilise solar power, whereas strategic localisation of the future hydrogen demand, as well as the possibility for storage positively influence the integration of wind power. The value of having flexibility of hydrogen demand and production diminishes with increased integration. This is partly due to lower-grade VRE resources and reduced co-benefits with the rest of the electricity system.

This techno-economic description of how VMS can be adapted to different purposes underscores the need for policy-makers to bear in mind that the needs of their systems are dependent upon the context and surrounding resources. It also emphasises the importance of combining different technologies and strategies and using them where they are most-appropriate, rather than deploying a single or all possible strategies for every scenario. If the cost-efficiency potential of variation management is utilised, variability of generation is unlikely to prevent the future electricity demand of Europe being met by low-cost electricity, which to a large degree will originate from wind and solar power.

5.3 Future work

There are many opportunities for future work that is directly connected to this thesis, regarding increased geographical, temporal, sectoral and technological scopes. By utilising the flexibilities that can be found in the electricity system today and in the future, sufficient flexibility can be found to balance in a cost-efficient way very high levels of wind and solar power. Nonetheless, transitioning from being techno-economically feasible to working in reality is not a simple process. Therefore, to actualise a rapid transition to systems with high levels of VRE, it will be necessary to implement VMS and to break other barriers, for which a better understanding of or at least further exploration of the socio-technical boundaries will be needed. In my opinion, NIMBY attitudes, for example, represent a major obstacle to efforts to promote high levels of acceptance for wind power, as well as other carbon-neutral electricity sources and VMS.

The questions as to the timing and magnitude of the investments for handling variability on different time-lines may be difficult to answer for several reasons connected to the speed of transition regarding electricity generation, electricity demand from electrification, and inter-annual variations. These questions will be addressed in future studies with multi-year data and a multi-annual time-frame, as well as in pathway studies, which also need a better understanding of the speed of growth and the associated costs.

Even if the electricity will be supplied from carbon-neutral sources, there is no guarantee that it also will be sustainable. Limitations linked to the availability of wind areas, metals, and bioenergy are not currently regarded as show-stoppers. However, if the system continues to grow such limitations may become debilitating. Considering current and future energy demands, not only the flexibility measures, but also the cost-efficiency of the measures are interesting to study.

Improved modelling of VRE integration in full energy system models could improve our understanding of: where best to allocate limited resources such as biomass; limited electricity availability as a consequence of poor acceptance of VRE; and the value of units that generate negative emissions. The ongoing efforts to create new models that can capture additional aspects or that identify improvements in connections between models at different system levels may be facilitated by the steps taken in this thesis towards understanding variability and the potentials of flexibility measures.

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