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RENEWABLE ELECTRICITY FOR ALL
UNTANGLING CONFLICTS ABOUT WHERE TO BUILD EUROPE'S FUTURE SUPPLY INFRASTRUCTURE

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Renewable electricity for all: Untangling conflicts about where to build Europe's future supply infrastructure

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Abstract

The European Union aims to fully decarbonise its electricity system by 2050 and relies largely on renewable electricity to reach this goal. A complete decarbonisation requires a large expansion of electricity infrastructure, such as wind farms, solar farms, and transmission lines. The expansion is controversially debated, with different preferences about which infrastructure should be built and where.

Preferences diverge for four reasons. First, infrastructure competes with other uses of land and alters landscapes. Second, location and size of renewable infrastructure projects determine ownership structures: large, centralised installations are better for large investors, while small, decentralised installations are better for small investors. Third, cost of electricity varies by region, based on the quality of locally available renewable resources. Fourth, the more electricity countries, regions, and municipalities generate locally, the less they must depend on imports.

In building upon the diverging preferences regarding these impacts, three dominant logics determine where and which renewable infrastructure should be built. Within the first logic, it should be driven by cost and thus built where it is cheapest. Within the second logic, it should be driven by location of demand and thus built within local communities. Within the third logic, it should be built in such a way that reduces impairment of landscapes. Because the three logics are conflicting, there is no consensus regarding infrastructure allocation. This lack of consensus may serve as a problem, as it increases opposition against developments and thus may slow or even stop the energy transition.

Within three contributions, I analyse the technical feasibility, economic viability, and land requirements of the three logics. My objective is to determine the extent to which the logics are possible, the extent to which they conflict, and whether compromise solutions exist that may relieve conflicts.

In the *first contribution*, I analyse the technical possibility of the demand-driven logic. By determining solar and wind generation potentials and contrasting them with today's electricity demand, I identify whether self-sufficiency is possible, or whether imports are necessary. I find that the generation potential of Europe and all countries within Europe is large enough to satisfy annual electricity demand. On the regional (subnational) and municipal scales, most places have the potential for self-sufficiency, though some do not – in particular, those with a high population density. My findings show that the demand-driven logic is technically possible in most places within Europe but that some places require electricity imports.

In the *second contribution*, I analyse the economic viability of the demand-driven logic and contrast it with the cost-driven logic. Using a dynamic model of the electricity system, I determine cost of electricity when there is unlimited trade on the continental scale (cost-driven logic), and when trade is limited to within countries or subnational regions (demand-driven logic). I find that cost increases with smaller scales and that the demand-driven logic leads to the highest cost. However, I find also that cost is primarily driven by where and how renewable fluctuations are balanced rather than where and how electricity is generated. While a trade-off between cost and scale exists, cost penalties of the demand-driven logic must not be large as long as fluctuations of renewable generation are balanced at continental scale.

In the *third contribution*, I analyse land requirements and the economic viability of the landscape-driven logic. Using the same model as before, I analyse the relationship between cost and land requirements of the electricity system by varying shares of solar and wind supply technologies. I find that the cost-minimal case (cost-driven) is based in equal parts on onshore wind and solar power on fields and requires some 2% of Europe's land, roughly the size of Portugal. Land requirements can be reduced by replacing onshore wind with offshore wind or solar power, but land must be traded-off against cost. Cost penalties, however, are not substantial: half of the land requirements can be avoided for an expected cost penalty of only 5% when onshore wind turbines are moved offshore. The findings demonstrate the economic viability of the landscape-driven logic.

My findings have two important implications for European energy policy and the transition to a decarbonised electricity system. First, I show that renewable electricity based on any of the three logics is technically feasible and economically viable almost everywhere in Europe. However, the logics have very different impacts on landscapes, economies, and societies. The question of where and which renewable infrastructure should be built is a normative question.

Second, I show that renewable electricity is feasible not only when strictly following one logic, but also by mixing aspects of the logics, and that necessary trade-offs must not be strong. For example, a system supplied primarily by solar power on the regional scale with continental trade for balancing, has low cost, low land requirements, and high local independence. Similarly, a system supplied by primarily offshore wind and solar power on the national scale has low cost, low land requirements, and high national independence. Such compromise solutions may not be ideal in any logic, but they may be acceptable to all, and thus have the potential to relieve conflicts and enable a faster energy transition.

Zusammenfassung

Die Europäische Union strebt eine vollständige Dekarbonisierung des Stromsystems bis 2050 an und setzt dabei verstärkt auf Strom aus erneuerbaren Energien. Eine komplette Dekarbonisierung erfordert eine grossflächige Expansion der Strominfrastruktur wie beispielsweise Windparks, Solarparks und Übertragungsleitungen. Die Details dieser Expansion werden kontrovers diskutiert und es gibt unterschiedliche Präferenzen, welche Infrastruktur gebaut werden soll und wo.

Die Präferenzen richten sich nach den folgenden vier direkten und indirekten Auswirkungen der Strominfrastruktur. Erstens: Die Strominfrastruktur verändert das Landschaftsbild und konkurriert mit anderen Flächennutzungen. Zweitens: Der Standort und die Grösse von Infrastrukturprojekten bestimmen darüber, wer sich an solchen Projekten beteiligen kann. Grosse, zentralisierte Projekte sind besser geeignet für grosse, professionelle Investoren, während kleine, dezentralisierte Projekte wie einzelne Windturbinen oder Solaranlagen auf dem Dach besser für kleine, private Anleger geeignet sind. Drittens: Der Standort bestimmt ebenso die Produktionskosten für Strom, da einige Standorte besser und andere schlechter für die Stromproduktion geeignet sind. Viertens: Durch einen höheren Anteil lokal erzeugten Stroms sind Länder, Regionen und Gemeinden weniger von Importen abhängig.

Auf diesen Auswirkungen der Strominfrastruktur beruhen drei wesentliche Ausbaulogiken, die definieren, wo welche Infrastruktur gebaut werden sollte. Nach der ersten Logik sollte dies kostenbasiert geschehen, nach der zweiten nachfragebasiert, das heißt geografisch nah am Verbrauch, und nach der dritten Logik basierend auf dem Landschaftsbild, sodass dieses möglichst wenig gestört wird. Da diese drei Ausbaulogiken sich teilweise widersprechen, gibt es keinen Konsens darüber, wo welche Strominfrastruktur gebaut werden sollte. Der fehlende Konsens stellt möglicherweise ein Problem dar, da er für Widerstand sorgt und so die Energiewende verlangsamen oder sogar stoppen könnte.

Mittels dreier Forschungsbeiträge analysiere ich in dieser Dissertation die technische und ökonomische Machbarkeit sowie den Flächenbedarf der drei Ausbaulogiken. Mein Ziel hierbei ist es herauszufinden, ob und inwieweit die Logiken realisierbar sind, inwiefern sie sich gegenseitig widersprechen und ob es Kompromisslösungen gibt, die den Konflikt zwischen den Logiken entspannen können.

Im *ersten Forschungsbeitrag* analysiere ich die technische Machbarkeit der nachfragebasierten Logik. Ich bestimme das Erzeugungspotenzial von Solar- und Windkraft, stelle es dem aktuellen Strombedarf gegenüber und bestimme so, ob

eine Eigenversorgung möglich ist oder ob Strom zusätzlich importiert werden muss. Ich zeige auf, dass das Erzeugungspotenzial in Europa und jedem europäischen Land gross genug ist, um den jeweiligen Strombedarf eines Jahres zu decken. Auf regionaler und kommunaler Ebene besitzen die meisten Orte ein ausreichendes Erzeugungspotenzial, allerdings gibt es einige Orte, an denen dies nicht der Fall ist. Diese Orte sind in den meisten Fällen urbane Gebiete mit hoher Bevölkerungsdichte. Meine Ergebnisse zeigen, dass die nachfragebasierte Logik in den meisten Gebieten Europas realisierbar ist, einige Gebiete jedoch Stromimporte benötigen.

Im *zweiten Forschungsbeitrag* analysiere ich die ökonomische Machbarkeit der nachfragebasierten Logik und stelle sie der kostenbasierten Logik gegenüber. Mithilfe eines dynamischen Stromsystemmodells bestimme ich die Kosten der Stromerzeugung für den Fall, dass kontinentaler Handel uneingeschränkt möglich ist (kostenbasierte Logik), und für Fälle, in denen der Handel nur auf Länderebene oder regionaler Ebene funktioniert (nachfragebasierte Logik). Ich zeige auf, dass die Kosten mit abnehmender Gebietsgrösse steigen und dass die nachfragebasierte Logik die höchsten Kosten erzeugt. Zugleich weise ich darauf hin, dass die Kosten vor allem durch das Ausbalancieren der Fluktuationen der erneuerbaren Energien getrieben werden, und weniger durch die Erzeugung des Stroms. Es gibt also einen Zielkonflikt zwischen Kosten und geografischer Grösse des Stromsystems, jedoch halten sich die Mehrkosten der nachfragebasierten Logik in Grenzen, solange Fluktuationen nicht nur regional, sondern auf dem ganzen Kontinent ausbalanciert werden.

Im *dritten Forschungsbeitrag* analysiere ich den Flächenbedarf und die ökonomische Machbarkeit der landschaftsbasierten Logik. Mithilfe des oben genannten Modells bestimme ich den Zusammenhang zwischen Kosten und Flächenbedarf von Stromsystemen mit unterschiedlichen Erzeugungstechnologien. Ich lege dar, dass ein kostenminimales System (kostenbasiert) ungefähr 2 % der Landfläche Europas bedeckt, was in etwa der Grösse Portugals entspricht. Der Flächenbedarf kann reduziert werden, indem Windstrom an Land durch Windstrom auf See oder Solarenergie ersetzt wird. Dadurch entstehen zwar Mehrkosten, diese müssen jedoch nicht hoch sein. So können z. B. Mehrkosten von 5 % den Flächenbedarf um 50 % reduzieren, indem Windstrom auf See anstatt an Land erzeugt wird. Diese Ergebnisse zeigen die ökonomische Machbarkeit der landschaftsbasierten Logik.

Aus meinen Ergebnissen lassen sich zwei wesentliche Schlussfolgerungen für die europäische Energiepolitik und die Energiewende ziehen. Erstens: Alle drei Ausbaulogiken sind fast überall in Europa technisch und ökonomisch realisierbar, haben jedoch sehr unterschiedliche Auswirkungen auf das Landschaftsbild, die Ökonomie und die Gesellschaft. Die Frage, wo welche Strominfrastruktur gebaut werden sollte, ist daher eine normative Frage.

Zweitens zeigen meine Ergebnisse, dass auch ein Mix der Ausbaulogiken technisch und ökonomisch möglich ist und die Zielkonflikte zwischen den Logiken nicht unbedingt gross sein müssen. Zum Beispiel ist ein System denkbar, das hauptsächlich durch Solarstrom auf regionaler Ebene gespeist wird und die Schwankungen der Stromerzeugung kontinental ausbalanciert. Ein solches System wirft geringe Kosten auf, benötigt nur wenig Fläche und besitzt eine hohe regionale Unabhängigkeit. Ausserdem möglich wäre ein System, das hauptsächlich durch Windstrom auf See und durch Solarstrom gespeist wird und das ebenfalls seine Stromerzeugung kontinental ausbalanciert. Auch dieses ist kostengünstig, hat einen geringen Flächenbedarf und eine hohe nationale Unabhängigkeit. Solche Kompromisslösungen sind zwar im Sinne der einzelnen Logiken nicht ideal, sie könnten aber für alle akzeptabel und somit geeignet sein, Konflikte zu entspannen und die Energiewende zu beschleunigen.

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Table of Contents

1 Introduction

1.1 Motivation and problem statement

The world is heating up. The previous decade has been the warmest in the history of temperature records (WMO, 2019), and the current year appears to be following this trend, with January 2020 being the warmest first month of any observed year (NOAA, 2020). With the Paris Agreement, the international community aims to stop this change of climate well before it reaches a global increase of 2° Celsius above pre-industrial levels (UN, 2015). While this target is still in reach, the window for reaching it is closing (IPCC, 2018).

As signatories of the Paris Agreement, the European Union and its member states committed to the goal of maintaining temperature increases well below 2° Celsius. To halt climate change early enough, emissions must be reduced quickly and entirely. The initial, nationally determined contributions of the European Union towards that goal sum to a reduction of emissions by at least 40% by 2030 compared to 1990. As part of the European Green Deal (European Commission, 2019), the European Commission recently claimed to raise this target to at least 50% by 2030 and aims to become climate-neutral by mid-century – meaning that any remaining emissions will need to be compensated for.

Becoming climate-neutral requires a complete or nearly complete decarbonisation of the electricity system. Technologies to achieve this are readily available today: renewable electricity, nuclear energy, and fossil fuel electricity with carbon capture and storage offer the possibility to provide low-carbon or even carbon-free electricity. Low social acceptance and low economic viability cause large deployments of the latter two technologies to be less likely, however, and the European Commission relies indeed on renewable electricity as the central decarbonisation option (European Commission, 2018). Future electricity supply in Europe can therefore be expected to be largely, or fully, based on renewable electricity.

Renewable electricity does, however, not come without controversies. While the technical feasibility and economic viability of largely or fully renewable electricity supply in Europe has been shown by some studies (T. W. Brown et al., 2018), the same points are questioned by other researchers (Heard et al., 2017; Sinn, 2017). Moreover, there is no consensus regarding which infrastructure must be built and where. This includes supply infrastructure such as solar and wind power, infrastructure for balancing renewable fluctuations such as battery storages and flexible generation from biomass combustion, and transmission infrastructure through which electricity is transmitted over long distances.

Opinions regarding this question diverge for four reasons. First, because of the direct impact that infrastructure has on local land. The infrastructure not only competes with other uses of land, but also visually impacts landscapes. Second, because of the impact on possible ownership structures: smaller, more distributed infrastructure suits better smaller investors such as communities or private households and is worse for larger investors whose asset portfolio often comprises large assets only. Third, because of the impact on cost of electricity. Solar power is likely to be cheapest in Southern Europe, for example, while wind power in the windiest places of Europe may be even cheaper. Fourth, because of the impact on import dependencies: while countries in Europe today are largely self-sufficient, this situation may change in the future, depending on where electricity is generated. Based on these impacts, different logics exist about the geographic allocation and type of electricity infrastructure in Europe, and opinions diverge regarding which logic is most appropriate.

Diverging opinions may be problematic for the transition towards renewable-based electricity supply. Only one system can be built, so a decision must eventually be made about where to build which infrastructure. Ignoring voices of proponents of some logics in this process may create frustration and potentially leads to opposition, for example against infrastructure projects such as wind farms or transmission lines, or politically (Späth, 2018; Stokes, 2016). Finding a shared logic, one for which everyone would strive, is likely not possible, considering that preferences are based on distinct ways of perceiving the world and therefore on fundamentally different opinions regarding what the problem is and what solutions may be (Lilliestam & Hanger, 2016; Verweij et al., 2006). Relieving the conflict between different preferences may instead require finding compromise solutions, which include bits and pieces of all logics. Without such compromise solutions, parts of the population are excluded from the energy transition, potentially leading to political barriers, or in extreme cases to halting the energy transition entirely.

In this thesis, I assess the technical feasibility, economic viability, and land requirements of the most prominent logics on renewable infrastructure allocation in Europe. In this way, I find out which logics are at all possible. Based on these findings, I discuss the extent to which the logics conflict and which possible compromise solutions exist. Such solutions may be able to relieve conflicts about future renewable electricity supply and, in this way, reduce barriers for a transition towards renewable electricity.

1.2 Logics of geographic allocation and types of infrastructure

While there is a growing consensus that renewables should be the dominant source of electricity in Europe, precisely how renewable electricity supply should be designed is controversially debated. Within the debate are three dominant logics – three sets of general rules where and which renewable infrastructure should be built. I discuss each of them as follows.

1.2.1 Cost-driven

In the first logic, the allocation of renewable infrastructure is driven by cost, and thus, economic efficiency determines which infrastructure to build and where to build it. A central instrument in this logic is a large and strong market because of its ability to reduce cost. Economic efficiency can be maximised by exploiting the best renewable resources in Europe, such as solar irradiation in Spain and wind speeds at the coasts of the Northern Sea. Tapping these resources requires connections to demand centres through sufficient transmission infrastructure.

A second driving force of this logic is the accompanying ownership structure. Renewable infrastructure in this logic can be expected to consist of large wind and solar farms, as they likely outcompete smaller units in the market. Large infrastructure projects serve as a prerequisite for large investors to engage in the development, as transaction costs of small projects such as single wind turbines or small arrays of photovoltaics are high.

The relationships between economic efficiency, project sizes, and ownership structure make this logic attractive to large corporations, such as those within the Desertec consortium (Lilliestam & Hanger, 2016), or the ones organised within the association Friends of Sustainable Grids (formerly Friends of the Supergrid) (Friends of Sustainable Grids, 2020). However, because low-cost electricity is in the interest of every European, this logic is favoured not only by corporations, and in fact, the European Commission is striving for a stronger international market for electricity as well (European Commission, 2015).

1.2.2 Demand-driven

Contrary to the first logic, allocation of infrastructure is driven by the location of demand in the second logic. Instead of generating electricity where it is cheapest, electricity is generated where it is used. This avoids the need for large transmission infrastructure as links between supply and demand are short.

While the limited transmission infrastructure may be considered an added benefit by some, the main motivation for this logic stems from the ownership structures that it allows and the independence it provides. Building generation units locally and at small scale lowers the entry barrier for the local population to invest in its own electricity supply. This diversifies the ownership structure, allows local communities to profit from electricity generation, and – in the eyes of a prominent proponent of this logic – can make the energy transition faster, as local communities have a larger interest in change than do corporations (Scheer, 2012). The large stakeholder base of this logic is sometimes considered to result in a more democratic form of electricity supply.

With all necessary infrastructure available locally, electricity supply based on this logic also leads to communities being independent from imports and price volatility (Rae & Bradley, 2012). Both benefits, diverse ownership structure and independence, cause many citizens and non-governmental organisations to favour this logic, with the three most prominent organisations on the European level being Eurosolar (Lilliestam & Hanger, 2016), 100% RES Communities (100% RES Communities, 2015), and REScoop (Friends of the Earth et al., 2018).

1.2.3 Landscape-driven

Finally, the third logic allocates necessary infrastructure based on the notion to respect landscapes. Compared to the combustion of fossil fuels, renewable electricity has a low power density and thus requires infrastructure that covers areas larger than today. As a result, landscapes must be industrialised by generation infrastructure (Gross, 2020). This is problematic because it competes with other uses of land, and may visually impair landscapes. Infrastructure allocation within this logic reduces these direct impacts on landscapes.

Electricity supply based on this logic avoids infrastructure with largest land requirements, high visibility, and within proximity of settlements. Instead, infrastructure is built far from demand centres, on land that is less valuable or perceived as less valuable and imported from these places (MacKay, 2008; Smil, 2015). Alternatively, electricity can be generated with no impact on land and with low visibility on rooftops. The former idea overlaps with the cost-driven logic, albeit without focussing on economic efficiency. Meanwhile, the latter idea overlaps with the demand-driven logic, albeit with a different motivation and problem perception.

1.3 Research objective and research questions

The transition towards decarbonised electricity must occur quickly to keep temperature targets of 2° Celsius or less in reach and it requires large deployments of renewable infrastructure. Conflicting preferences about exactly how renewable supply should be designed could slow or even stop the transition. To ensure the transition can occur quickly enough, these conflicts must be relieved.

In this thesis, I explore whether renewable electricity supply in Europe is possible by considering aspects of *all* logics outlined above. Such compromises would not lead to futures that are ideal in any of the logics: they could not use the best resources, strengthen local communities, and conserve landscapes as much as desired. By incorporating elements from all logics, however, they may be acceptable to all and may lower political barriers of a transition towards renewable electricity.

I analyse the three logics based on three analytical dimensions, one in each of the main contributions of this thesis. First, I assess the generation potential to understand whether such renewable supply is at all technically possible. Second, I assess the economic viability to understand the cost of each kilowatt-hour of electricity, and whether this cost is a limiting factor. Third, I assess the amount of land required for infrastructure and how land requirements are geographically distributed. For all assessments, I study each logic in isolation.

Beyond studying logics in isolation, I assess mixed forms in which electricity supply is based on more than one logic. Doing so enables me to identify which compromises between the logics may be possible and what their downsides in terms of technical limitation, economic viability, or land requirements may be. This research objective leads to three research questions that I answer within this thesis.

The **first research question** concerns a necessary condition for renewable electricity: its generation potential. The potential defines a technical limitation and is particularly relevant for the demand-driven logic. Only if the generation potential is sufficiently large can a local community power itself. However, there is reason to believe that potentials and the sufficiency of potentials depend on the geographic extent and the location of the electricity system. Small systems have access to fewer and potentially worse renewable resources and thus may not be able to power themselves. Targeting this relationship, I ask *on which geographic scales is the potential of renewable electricity in Europe large enough to satisfy annual demand?* I provide a synopsis of the answer in Section 1.5 and a detailed answer in Section 2.

The **second research question** concerns the economic viability of renewable electricity supply. It is particularly relevant for the cost-driven logic because of its focus on economic efficiency. In the logic, large-scale electricity systems have low cost because they provide access to the best and therefore lowest-cost resources. Accordingly, smaller-scale supply – for example as considered within the demand-driven logic – must have a lower economic efficiency. To understand how strong the cost-decreasing effect is, I ask *how does total system cost of fully renewable electricity supply in Europe change with geographic scale?* I provide a synopsis of the answer in Section 1.6 and a detailed answer in Section 3.

The **third and final research question** handles concerns about negative impacts on landscapes. Renewable electricity has a low power density and requires significant amounts of land, thus changing local landscapes. Some supply technologies have lower requirements for land than others but also have different cost. I explore the possibilities of low land requirements and ask *which solar and wind supply technology reduces land requirements of fully renewable electricity most cost-effectively in Europe?* I provide a synopsis of the answer in Section 1.7 and a detailed answer in Section 4.

1.4 State of the art

To conduct the research outlined above, I rely heavily on previous work. I build upon methods that have been developed previously, on data that has been gathered or generated for various purposes, and on research and general-purpose software developed and publicly distributed by scientists and software engineers. Despite the richness of the existing set of tools, it is not sufficient for answering my research questions and therefore I need to push the state of the art to perform my own research. In the following, I describe the methodological advances required for answering my research questions.

1.4.1 Potentials of solar and wind power on high spatial resolution

The total potential of electricity that can be generated from solar and wind has previously been estimated to exceed global electricity demand (Cho, 2010). However, renewable electricity is not without its limits, and this is even more true when narrowing the geographic extent from the global to the local. To be able to answer the first research question, but also to be able to conduct research for the other two research questions, I require estimations of the potentials of solar and wind power on geographic scales that are smaller than those that have been assessed so far.

The potential of renewable electricity is determined to the largest part by two aspects: the space available for the infrastructure, and the local meteorological conditions. Both can vary strongly between two locations in Europe, or even between two locations in the same municipality. Thus, rigorous potential estimations require high spatial resolutions. Combined with the large geographic extent of my research – the entire continent – this provides a computational challenge. For example, to cover areas not larger than 300 m by 300 m, potential estimations for 300 million locations are necessary. This computational challenge explains why most previous estimations are either performed on high resolution and with high accuracy but for limited geographic extents, or on lower resolution for larger extents.

This is especially true for assessing the potential of rooftop PV. The particular difficulty here is determining the amount of roof space available, including its orientation and tilt. Previously, two types of methods have been applied. The first type has lower accuracy and relies primarily or entirely on statistical data (e.g. (Defaix et al., 2012)). Methods of this type may, for example, take population count as a proxy for available roof space. While this type may not have the best accuracy, it is easily applicable to large areas. The second type is based on geospatial data of high resolution (e.g. (Buffat et al., 2018)). The data may be derived from cadasters and generally has higher accuracy. For large geographic extents, required datasets are large and computationally hard to handle. Even more importantly, there exists no readily available dataset for Europe today. For these reasons, no continental-wide estimation has previously been performed, and thus, both the total European potential for rooftop PV and the potential of each municipality in Europe are unknown.

I am extending the state of the art by using two datasets with very high spatial resolutions. First, I use the European Settlement Map (Ferri et al., 2017), which is a 2.5 m resolved geospatial dataset derived from satellite images. The raw images have been processed automatically to distinguish built-up areas from non-built-up areas and detect buildings within built-up areas. The building footprints in this dataset cannot be used directly, because the automatic processing introduces a bias and detects all structures, no matter whether they are suitable for roof-mounted solar power. To correct for this bias, I use a second dataset of very high spatial resolution derived from aerial images which contains the roof space of each building in Switzerland – sonnendach.ch (Swiss Federal Office of Energy, 2018). With it, I bias-correct the European Settlement Map data for Switzerland and then apply this bias correction to data in all other European countries. Furthermore, I use the Swiss dataset to derive information about the orientation and tilt of roof areas. This new method allows for estimating the potential of rooftop

PV with high accuracy and high spatial resolution for all of Europe. The derived data (Tröndle, Pfenninger, & Lilliestam, 2019a) and the automatic workflow to reproduce the data is publicly available (Tröndle, 2019).

1.4.2 Multi-scale model of the European electricity system on high spatial and temporal resolutions

To be able to accurately assess necessary electricity infrastructure and cost of fully renewable electricity, I require a model of the European electricity system that covers fluctuations of renewables. Renewable electricity fluctuates on almost all time scales, from seconds to years. For this type of analysis, relevant time scales are in the range of hours to years and thus require a model that is medium to highly resolved in time. Together with the high spatial resolution, this provides a computational challenge that, to my knowledge, has not been addressed in energy system research so far. Previous studies that analyse the European power sector are most often performed using national resolution or lower, resulting in fewer than 40 assessed locations (Child et al., 2019; Gils et al., 2017; Schlachtberger et al., 2017; Zappa et al., 2019). The highest spatial resolution in previous studies involves 362 locations (Hörsch & Brown, 2017) in the model PyPSA-Eur (Hörsch et al., 2018). However, this is still not enough to cover all 502 regions in Europe. To be able to answer the second research question about cost on small and large geographic scales, this computational challenge must be overcome.

As a computational challenge, the problem can partially be overcome simply through better computational resources. Indeed, the research I am conducting is only possible thanks to having access to a high performance computing cluster: ETH's Euler supercomputer (Scientific IT Services ETH Zürich, 2020). However, the challenge cannot be overcome purely based on brute force, because the computational requirements of a poorly configured model can easily skyrocket. In addition, modern algorithms to solve this type of mathematical problem (Gurobi Optimization, LLC, 2020) are prone to numerical sensitivities, and may not be capable of finding a solution, no matter the performance of the underlying hardware. I solve this issue by scaling the model formulation to control numerics which allows me to answer the second research question despite of its high spatial resolution. To my knowledge, the method has not been applied in energy system analysis before.

In addition to being highly resolved, the model must furthermore be flexible enough to function on all scales, from subnational scales to continental scale, and from hourly resolution to a resolution of a few hours. This is necessary to adapt the resolution to the research question at hand. To answer the third research question, I require a model with a scale different than that of the second research question.

I achieve this by using the flexible, existing modelling framework Calliope (Pfenninger & Pickering, 2018) and by applying methods from software engineering in the modelling process. Previously, energy system models were created in a manual process and distributed as is. This approach has the disadvantage that resolutions are baked into the model and cannot easily be changed. Instead, I apply a workflow-based approach that automates the model generation process. In this way, a model with any resolution can be repeatedly built from raw data only. Originating in software engineering, the method and tools to support it are applied in some fields of research, such as bioinformatics, but are not yet the norm in energy system analysis. By using the workflow management system Snakemake (Koster & Rahmann, 2012), I am able to generate models on different scales and make the model creation and the analysis of model results reproducible. The workflow to generate the model I use to answer research questions number two and three is publicly available (Tröndle, 2020a).

1.4.3 Dealing with parametric uncertainty

Answering any of the research questions with state-of-the-art renewable electricity technologies would not be very meaningful. Cost of technologies is constantly decreasing, especially in the case of photovoltaics, in which it has decreased drastically in the past (Creutzig et al., 2017). Similarly, conversion efficiencies are increasing, leading to lower land requirements of generation infrastructure. There is no reason to believe that these trends will stop. Any of my research's findings may be outdated in a few years due to this rapid technological change. By the time Europe's electricity system is fully decarbonised, it is likely that findings based on today's technology will be invalid.

To derive more meaningful findings, I therefore use future technology in my research rather than state-of-the-art technology. I assess future technology cost for a case in which the technology is deployed at global scale. At such a point in the future, cost can be considered to be in a quasi steady state compared to the vigorous cost dynamics of today. The following hypothetical example may help to illustrate the logic: Assume that global electricity is provided to 100% by renewable electricity in 2050, technology cost decreases by 6% for each doubling of technology deployment, and technology lifetime is 20 years. In this case, total system cost in 2070 would be only 6% lower than in 2050, and in 2110, it would be less than 12% lower than in 2050. This cost decrease is so slow that cost in 2050 can be considered to be in quasi steady state. It is this quasi steady state that I am assessing in my research questions: the medium- to long-term case.

Assessing medium- to long-term technology comes with the challenge that future technology parameters cannot be known with certainty, which may again invalidate findings. For example, I may find that small-scale electricity has higher cost than large-scale electricity because of battery cost. However, battery cost may fall stronger than expected, which may invalidate this finding. To ensure that findings are robust, uncertainties in technology must be considered. While some uncertainty analysis methods are used in energy system analysis, most methods cannot grasp uncertainty in its entirety.

The most common uncertainty analysis methods in the literature are scenario analyses (Gils et al., 2017; Schlachtberger et al., 2018; Zappa et al., 2019) and local sensitivity analyses (Gils et al., 2017; Schill & Zerrahn, 2018; Schlachtberger et al., 2017). In scenario analyses, consistent sets of technology parameters are used to form scenarios – typically anything between 2 and 10. These scenarios often contain minimum and maximum cases to cover the full possible range. Local sensitivity analysis extends beyond scenario analysis and more thoroughly analyses the impact of single parameters than does scenario analysis. Both methods have the drawback of examining only a small fraction of the entire uncertainty. I advance the field of energy system analysis by applying global Monte Carlo methods, global sensitivity analysis, and surrogate models.

In global Monte Carlo methods and global sensitivity analysis, the entire uncertainty space is examined, in contrast with scenario or local sensitivity analysis. For example, I am not only considering cases in which cost of batteries is lower than expected, but I am also considering cases in which cost of solar power is at the same time higher – or lower – than expected. Only in this way can I explore the entire uncertainty range of future electricity systems. Global sensitivity analyses have been applied to some energy system analyses in the past (Moret et al., 2017), but not for models with high spatial and temporal resolution.

One reason why global methods have not been applied is their complexity and computational requirements. Energy system models with high spatial and temporal resolution are often difficult to run only once, but global methods require thousands or even hundreds of thousands of runs or more, which can be prohibitive. To be able to perform global sensitivity analysis, I apply a method developed in the field of civil engineering (Le Gratiet et al., 2017; Sudret, 2008), which derives a surrogate model. This model has the same input-output behaviour as the original model but can compute the behaviour orders of magnitudes faster. Only using this method – which has never been applied in energy system analysis – is it possible conduct a global sensitivity analysis of a computationally challenging model, as is the one I am using. This allows me to find robust relationships when answering research questions two and three.

1.5 Synopsis of contribution I

The demand-driven allocation logic aims for a bottom-up governed and owned supply system, with people from local communities becoming stakeholders. This contrasts with the situation today, in which they are merely consumers. The logic aims to strengthen the local community and strives for self-sufficiency, without the need to import electricity from distant locations through trade with third parties. The foundation of this logic is thus the possibility to generate electricity locally in sufficient quantities. Whether this possibility exists is not known, however.

Self-sufficiency is not possible in most places with today's dominant sources of electricity – fossil and nuclear fuels. While fuels can be combusted nearly anywhere, they are not available everywhere and must therefore be imported into these places. This contrasts with renewable electricity, which, in principle, can be generated everywhere – as long as the sun shines and the wind blows. However, the sun and the wind are sometimes more and sometimes less strong, depending on the meteorological conditions of locations in Europe. In some of these cases, they may not be enough to supply local electricity demand. In addition, renewable electricity has a low power density and therefore requires large amounts of land. Local communities may simply not have enough land available to generate the necessary amounts of electricity. Whether a community can be self-sufficient likely depends on its geographic extent as well. Smaller communities have access to smaller and less diverse resources in terms of land and renewable sources.

Previous studies have analysed the generation potential of individual technologies in individual municipalities, regions, or countries (Caglayan et al., 2019; McKenna et al., 2015). However, no study assesses the relationship between geographic scale and the possibility for electricity self-sufficiency for all of Europe. Thus, my co-authors and I answer the following question in this first contribution: *On which geographic scales is the potential of renewable electricity in Europe large enough to satisfy annual demand?*

To answer this question, we estimate current, annual electricity demand and the generation potential of renewable electricity for each administrative unit on four geographic scales: continental, national, regional, and municipal. We consider the dominant and expandable forms of renewable electricity only: onshore and offshore wind turbines, and photovoltaics on roofs and fields. We assume electricity self-sufficiency as being possible from a pure resource perspective when the generation potential is larger than electricity demand and certainly impossible when the potential is below demand.

Potential estimations of renewable electricity can vary drastically depending on which aspects are considered. Technical aspects form the foundation of every potential estimation: geographic conditions, meteorological conditions, and technical parameters of energy conversion. While different analyses considering only technical aspects may lead to different results, the differences between estimations are typically not large. Socio-political aspects, however, can have large impacts on potential estimations and may lead to results that are different by orders of magnitude. For example, local authorities may *decide* against the use of existing potentials to protect residents or landscapes. Considering these aspects in potential estimations is challenging, first because they are difficult to predict, and second because they are potentially different in every municipality. For example, in Germany, while a law exists regarding minimum distances of wind turbines to dwellings on the national level, the exact law can be superseded by regional and municipal authorities. We circumvent this uncertainty by determining two types of potentials: first, a potential based on technical aspects only which serves as an upper bound – the technical potential. Second, a potential restricted by a set of social rules which we apply Europe-wide: the technical-social potential. Here, we prohibit PV on agricultural land to avoid land-use conflicts and allow the use of only a fraction of all available surfaces. We deliberately omit economic aspects, because we want to understand where self-sufficiency is possible, not whether and where it is economically viable.

Our first result is that generation potentials of renewable electricity are vast on the **continental scale**. When we apply only technical restrictions, the potentials sum to more than 220,000 TWh/yr and thus exceed current electricity demand more than 70 times. Even the strict technical-social potential could supply an electricity demand more than four times as large as the current European one. There is little reason to believe that Europe could not generate enough renewable electricity to become self-sufficient.

All four supply technologies – onshore and offshore wind, and utility-scale and rooftop PV – have roughly the same technical-social potential on the order of current European electricity demand. The non-technical constraints restrict utility-scale PV the most, whose technical potential is by far the largest. Prohibiting photovoltaics on agricultural land in the technical-social case greatly reduces the potential. Allowing for solar energy generation on farm land – for example in the form of a dual land-use with agriculture – can greatly increase the total potential of renewable electricity.

On the **national scale**, the result is similar, and we do not find a single country whose potential for renewable electricity is too low to become self-sufficient – even if we apply strict technical-social constraints. However, the magnitude of the potential varies strongly among countries. In Switzerland, Belgium, and Luxembourg, the technical-social potential of solar and wind power is less than twice current electricity demand. In Latvia, on the other hand, the potential exceeds demand more than 20 times. If countries apply constraints on the deployment of renewable electricity that are stricter than those we consider, some countries will not be able to become self-sufficient.

When we further decrease the geographic scale, we find that not all subnational regions have the potential to become self-sufficient. On the **regional scale**, five densely populated cities have insufficient technical potential: Brussels, Basel, Oslo, Vienna, and Berlin. The remaining 497 regions have sufficient potential, though some exceed electricity demand only marginally. The situation becomes more pronounced when considering the technical-social constraints, in which case four times as many regions have insufficient potential (see Figure 2.4). While self-sufficiency through the use of renewable electricity is possible in most places, it is not possible everywhere.

Last, on the smallest geographic scale, the **municipal scale**, the trend continues: approximately 7,000 municipalities have insufficient technical-social potential, particularly municipalities with high population density. While this means that only 5% of all municipalities are affected, these municipalities are the home to one quarter of the European population (see Figure 2.4). Self-sufficiency is in most cases possible only for municipalities with low population density.

In summary, we find that the possibility for self-sufficient renewable electricity supply in Europe decreases with geographic scale. While the generation potential is high enough on the continental and national scales, the potential is insufficient in some subnational regions and in population-dense municipalities. On the smallest scale, up to 25% of the European population lives in a municipality with insufficient renewable electricity supply.

Our findings have three important implications for the demand-driven allocation logic in Europe. First, local (i.e. municipal) self-sufficiency is possible in most municipalities in Europe and for about three quarters of the European population. For the remaining municipalities, primarily population-dense cities and metropolitan areas, it is not possible. These municipalities must rely on imports from their encompassing regions and in some cases even from outside.

Second, untouched landscapes can be traded off against the possibility for self-sufficiency. By reducing social restrictions on the deployment of renewable supply infrastructure, the share of municipalities and of the population that can be self-sufficient can be increased: from 95 to 97% and from 75 to 86%, respectively. The higher numbers are the result of considering technical restrictions only. Doing so would allow for an additional 2% of municipalities and 11% of European population to be self-sufficient, albeit at the cost of accepting infrastructure that is denser and potentially prohibiting other land uses.

Third, future renewable electricity supply in Europe with self-sufficiency on small scales would be geographically strongly concentrated. The demand-driven allocation logic is often said to result in a distributed and decentralised electricity supply. While this may be true in terms of size, number, and ownership of generation units, the logic also moves supply infrastructure close to demand – leading to a geographic concentration around population dense areas. This concentration must not be an issue, particularly when generation infrastructure sits primarily on rooftops. Where this is not possible, non-built-up land would be required to generate electricity, potentially creating conflicts with people concerned about the conservation of local landscapes. The concentration of supply infrastructure is a necessary trade-off for electricity self-sufficiency on the local scale.

1.6 Synopsis of contribution II

The cost-driven allocation logic builds on economic efficiency as its primary driver. Larger markets are generally assumed to be more efficient and have the potential to reduce cost. Based on this logic, continental-scale supply would be lowest-cost, whereas cost would be higher at national and regional scales. However, continental-scale electricity conflicts with the demand-driven allocation logic in which supply is located at small scales.

Mainly two reasons have led to the belief that renewable electricity supply on large scale is more economically efficient. First, the quality of renewable resources varies based on location within Europe. For example, solar irradiation is strongest in the southern parts of Europe, while wind speeds are highest at the coasts of the Northern Sea and the Atlantic Ocean. Electricity can be generated with lowest cost in these places, all other things equal. Only if electricity is traded continentally can these cost benefits be obtained at large scale. Second, renewable electricity fluctuates constantly, and these fluctuations must be balanced. Without trade between regions and countries, fluctuations must be balanced locally with electricity storages or flexible generation, both of which are expected to be costly. With trade in a continental-scale system, fluctuations can be balanced with lower cost by exploiting low correlations of fluctuations between distant locations and through the possibility of sharing balancing infrastructure between locations. Both effects may cause continental-scale electricity to be economically most efficient.

In fact, previous studies have found lower cost on larger scales for case studies in Europe (Child et al., 2019; Gils et al., 2017). However, no study assessed both effects in isolation and for several geographic scales. Therefore, my co-authors and I target the following question in this contribution: *How does total system cost of fully renewable electricity supply in Europe change with geographic scale?* To be able to differentiate between the two effects, we further differentiate geographic scale: *Supply scale* determines on which scale electricity is generated and thus allows us to assess the impact of access to high quality resources. *Balancing scale*, in contrast, determines on which scale fluctuations must be balanced and allows us to assess the impact of lower correlations of supply and the sharing of balancing infrastructure. Using a cost-minimising, dynamic model of the European electricity system, we analyse the relationship between both scales and cost on the regional (subnational), national, and continental levels.

Our first finding is that total system cost does indeed fall with larger scales. With both scales being continental, cost of electricity is lowest: roughly 0.05 EUR per kWh consumed. Smallest scale electricity, with supply and balancing on the regional scale, has cost that is 70% higher than in the lowest-cost, continental-scale case. A trade-off exists between cost and full self-sufficiency on small scales.

Second, we find that balancing scale impacts cost more strongly than supply scale. As long as balancing scale remains continental, the cost penalty of regional-scale electricity supply is only 20% compared to the lowest-cost, continental system. In this case, regions are net self-sufficient rather than fully self-sufficient: they generate enough electricity to fulfil annual electricity demand, but they trade within the year to balance renewable fluctuations with trade summing up to zero. Regional net self-sufficiency is possible at small cost penalties.

Our third finding is that cost benefits on the supply scale come with a geographic concentration of generation infrastructure and therefore, extensive transmission grids. Lowest-cost renewable electricity can be generated with wind farms along the coasts of Europe, and to maximise economic efficiency, these potentials must be exploited fully. Such cost minimisation leads to a concentration of generation infrastructure in places with the best resources. To transport electricity from the coasts to demand centres, a transmission capacity of two times today's capacity is necessary. Cost of regional net self-sufficiency can be reduced from 120% to 100% by moving supply infrastructure to the best locations in Europe, but at the cost of large transmission infrastructure requirements and concentration of generation assets.

Last, continental-scale balancing requires transmission capacity on the order of today's capacity, albeit with a different geographic configuration. In particular, international transmission capacity is too weak to fully support this form today. Thus, cost of regional-scale electricity can be reduced from 170% to 120% by allowing for continental-scale balancing, but doing so requires a doubling of today's international transmission capacity.

Our findings have three important implications for the cost- and demand-driven allocation logics. First, pure economic reasoning demands a continental-scale system due to its lowest cost, but this leads to an electricity supply that is geographically skewed: generation is concentrated and requires large transmission capacities to reach demand. This has implications on exporting regions, importing regions, and all regions in between. Specifically, exporting regions will need to accept high amounts of generation infrastructure, importing regions will need to accept high dependencies on their trading partners, and regions in between will need to accept transmission infrastructure from which they do not profit. To build such a system, social and political acceptance must be ensured.

Second, fully self-sufficient electricity on the regional scale requires a large cost penalty, but one which can possibly be traded off for independence with sufficient political will. While the cost penalty is 70% on the European average, some regions would need to pay less to achieve full self-sufficiency. However, each region that drops out of the market would likely increase cost for all others. Thus, a scheme in which only some regions become fully self-sufficient does not have the potential to ease the conflict between the demand- and cost-driven allocation logics.

The potential to relieve the conflict between logics may lie in another form of future electricity supply, in which regions generate renewable electricity in sufficient amounts to cover their annual demand, but trade with their neighbours to balance fluctuations. To enable this form of electricity supply, cooperation between regions and countries must be intensified: transmission capacities must be expanded among countries, and efficient international electricity markets must be established. As a compromise between cost and independence, regional net self-sufficiency may serve as an acceptable solution for both sides.

1.7 Synopsis of contribution III

In the landscape-driven allocation logic, fully renewable electricity is generated without impairing landscapes. If and how renewable infrastructure impairs landscapes is subjective and an agreement is not easy to find, not even among proponents of the logic. Renewable supply that requires less land would likely impact landscapes less, however. Thus, I am assessing total land requirements as a proxy for landscape impact in the following.

When considering spacing between turbines, onshore wind farms have high land requirements, even among renewable electricity. Only farming for biofuels and (depending on the location) hydroelectricity can require more land to generate the same amount of electricity, and the expansion of both is – partially because of that – politically not supported in Europe. However, other dominant technologies are available to generate renewable electricity with lower or no land requirements: utility-scale and rooftop photovoltaics, and offshore wind. In principle, total land requirements of fully renewable electricity could therefore be reduced by replacing onshore wind capacities with any of the three alternatives.

Alternatives come with different cost and requirements for balancing compared to onshore wind, however. Thus, it is therefore not known whether switching to any of these technologies would lead to cost penalties and what their magnitude would be. While some studies have discussed differences in land requirements or cost on the technology level, no study has assessed the relationship between cost and land requirements on the system level, including impacts on balancing. This leads me to the research question of this third contribution: *Which solar and wind supply technology reduces land requirements of fully renewable electricity most cost-effectively in Europe?*

To answer this research question, I use a nationally resolved model of the electricity system that determines balancing requirements, total land requirements of wind and solar technologies, and total system cost based on different shares of supply technologies. I consider each country to be net self-sufficient and apply the same supply share in each country.

I find that, first, cost-minimal land requirements are 97,000 km^2 (2% of total land) to satisfy current electricity demand. Such a system would be powered to equal parts by onshore wind and utility-scale PV, with no contribution of offshore wind or rooftop PV as they are not cost-competitive. Among all other necessary infrastructure, only the transmission grid (~0.5%) and hydroelectricity (~1%) can be expected to have relevant land requirements, and thus, total cost-minimal land requirements are roughly 3.5% of Europe's land.

Second, to reduce land requirements of the cost-minimal case, land must be traded off against cost. Replacing onshore wind with offshore wind is the most cost-effective option to do so. Replacing onshore wind with utility-scale PV and rooftop PV can also reduce land requirements, but at higher cost. Land requirements can be reduced by 50% with cost penalties of 5%, 10%, and 19% using these options. All three options can reduce land requirements even further by accepting higher cost penalties.

Third, while there is uncertainty about cost and land requirements of supply technologies, cost penalties larger than 20% are unlikely to maintain land requirements below 1% of total land when using offshore wind or utility-scale PV. Only in a quarter of the cases are larger cost penalties necessary. Even when a lower target of 0.5% of Europe's land is the goal, cost penalties are more likely to be less than 20%. Renewable electricity with low land requirements is possible, with cost penalties less than 20% in most cases.

My findings have important implications for the landscape-driven allocation logic, but also the cost- and demand-driven logics. First, conflicts about altered landscapes can be relieved with higher shares of offshore wind, utility-scale PV, or rooftop PV. Increasing these shares can lead to sharp reductions in land requirements. A trade-off exists between land requirements and cost of the electricity supply, but cost penalties, even for large reductions in land requirements, are likely to not be prohibitive.

Second, the solutions I present here do not conflict or do not conflict strongly with other logics. As long as onshore wind is replaced by photovoltaics of either type, reducing land requirements must not conflict with the demand-driven logic. The trade-off between cost and land requirements collides with economic efficiency in the cost-driven logic, however. Still, because cost penalties of only a few percent can lead to large reductions in land requirements, the solutions may offer the potential for compromises between the two logics.

2 Home-made or imported: on the possibility for renewable electricity autarky on all scales in Europe

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Abstract

Because solar and wind resources are available throughout Europe, a transition to an electricity system based on renewables could simultaneously be a transition to an autarkic one. We investigate to which extent electricity autarky on different levels is possible in Europe, from the continental, to the national, regional, and municipal levels, assuming that electricity autarky is only possible when the technical potential of renewable electricity exceeds local demand. We determine the technical potential of roof-mounted and open field photovoltaics, as well as on- and offshore wind turbines through an analysis of surface eligibility, considering land cover, settlements, elevation, and protected areas as determinants of eligibility for renewable electricity generation. In line with previous analyses we find that the technical-social potential of renewable electricity is greater than demand on the European and national levels. For subnational autarky, the situation is different: here, demand exceeds potential in several regions, an effect that is stronger the higher population density is. To reach electricity autarky below the national level, regions would need to use very large fractions or all of their non-built-up land for renewable electricity generation. Subnational autarky requires electricity generation to be in close proximity to demand and thus increases the pressure on non-built-up land especially in densely populated dense regions where pressure is already high. Our findings show that electricity autarky below the national level is often not possible in densely populated areas in Europe.

2.1 Introduction

Renewable electricity, nuclear power, and carbon capture and storage are the main supply-side options to decarbonise the electricity system in Europe. Among these three, renewable electricity is the only option to not deplete the energy resource it depends on, but its resource has another unique characteristic: it is available everywhere, in different intensities. This makes it possible to generate electricity from local resources and decrease imports – and it could allow regions to become electricity autarkic, i.e. eliminating imports altogether. This would be in stark contrast to today's situation, in which the European Union relies on primary energy imports for more than a third of its electricity (Publications Office of the European Union, 2017), and in which Member States trade significant amounts of primary energy and electricity within the European Union. A transition to renewable electricity might hence not only allow the European Union, its Member States, or regions in Europe to decarbonise their electricity systems but also to become autarkic.

Proponents of local electricity generation bring up the benefits of increased electricity security, improvements to the local economy and its sustainable development, and community involvement. Local generation is seen as a reliable source of electricity, with supply and price determined within a political unit's own borders. As such, autarky would decrease dependency on others and increase electricity security (Abegg, 2011). Positive effects on the local economy are expected, as value creation happens within the region, thus decreasing the outflow of capital. Installation of generators, and their maintenance and operation, are furthermore expected to create jobs locally (Abegg, 2011; Müller et al., 2011). The resulting increase in economic activity will improve the attractiveness of the regions and thereby counteract emigration from peripheral regions to the cities (Abegg, 2011; Müller et al., 2011). Lastly, (Ecker et al., 2017; Engelken et al., 2016) show that self-sufficiency is important to the local community, and (Müller et al., 2011; Rae & Bradley, 2012) discuss case studies, in which the involvement of the local community in transition processes has improved the willingness to change and has reduced public opposition.

There are also arguments against local autarky, in particular concerning the cost and stability of small electricity systems. Larger renewable electricity systems often have lower costs, because of a more efficient use of resources and because the best renewable resources can be used by everybody – whereas in an autarkic setting, one must use what is available locally, regardless of the quality. Electricity demand may rise due to a less efficient use of resources, for example when electricity cannot be used or stored locally at the time it is generated (Czisch, 2005; Patt et al., 2011; Schlachtberger et al., 2017; Schmid & Knopf, 2015; Steinke et al., 2013). Positive effects on the local economy through local value creation will be diminished, or eliminated, as both technology and know-how for installation and operation will often need to be imported from other regions or countries – the specialist knowledge is not readily available everywhere. Lastly, the land footprint for electricity generation is high and can lead to land use conflicts, for example with local food or feed production (Schmidt et al., 2012). Thus, some authors have pointed out that the benefits of cooperation and autarky can be combined when full autarky is replaced by local generation embedded in a larger system (Battaglini et al., 2009; Schlachtberger et al., 2017).

Because there are advantages and disadvantages, there is no consensus in European policy as to which degree local generation should be promoted or integration should be strengthened. On the one side, there are many initiatives on the global (Go 100% Renewable Energy, Global 100%RE), European (100% RES communities, RURENER), and national levels (CLER, Community Energy Scotland, 100ee Regionen Netzwerk) that promote local generation as part of their agendas. Autarky is often discussed in an on-going debate about decentralisation of the electricity system (Funcke & Bauknecht, 2016; Lilliestam & Hanger, 2016; Scheer, 2012), but decentralisation (in terms of plant sizes, grid structures, and ownership) and autarky are distinct aspects of the electricity system: decentralised systems are not necessarily autarkic, and autarkic systems must not be decentralised. Existing projects are often in rural areas, while for cities and towns it is acknowledged that autarky will be more difficult and thus, they are advised to focus on improving energy efficiency instead (Buschmann et al., 2014). While these initiatives promote local generation, they do as well promote cooperation, but only on the regional level: between municipalities (100ee Regionen-Netzwerk, 2015; 100% RES Communities, 2015), and in particular between cities and their encompassing rural municipalities (Buschmann et al., 2014).

On the other hand, the European Commission and the European Network of Transmission System Operators for Electricity (ENTSO-E) strive for stronger electricity cooperation in Europe. While they do not oppose local generation, they both emphasise the benefits, especially the cost-decreasing effect, of integration and electricity trading among European countries (ENTSO-E, 2018; European Commission, 2015). Thus, the Commission is striving for the establishment of a single internal energy market through the harmonisation of market mechanisms, support schemes, and network codes. Regarding autarky on the European level, the Commission seeks to lower import dependency, but it does not target full autarky in terms of European import dependence. Instead, it aims to increase diversity of foreign energy suppliers and energy sources. With this strategy, the EU strives to increase the use of local resources, but it is certainly not striving for autarky on the national or subnational levels.

Despite the on-going debate whether Europe should strive for autarky to reach potential benefits, we do not know whether electricity autarky is possible for Europe, its nations, or regions. The source of uncertainty stems from another characteristic of renewable electricity: its large land footprint compared to other sources of electricity (Cho, 2010). We know that electricity autarky at the European level or below will require large areas devoted at least partially for electricity generation, but not whether sufficient areas are available in each country, region or municipality – or, if they are, how much of the land needs to be reserved for electricity generation.

The objective of this article is to identify whether and in which places electricity autarky is at all possible in Europe, and which shares of land must be devoted to electricity generation in the cases where electricity autarky is possible.

We do this by quantifying the potential of renewable electricity with high spatial resolution and comparing it to today's electricity demand. We consider the four administrative levels that exist in nearly all European countries: the continental, national, regional (first-level administrative division), and municipal levels. All units on all four levels have their own local governments which could, in principle, decide to declare electricity autarky. We consider onshore and offshore wind power, and photovoltaics in our analysis as these technologies have the highest potential (Cho, 2010), while excluding biomass and hydropower (see below). The geographic scope of our study comprises the countries with member organisations in the ENTSO-E: EU-28, EFTA without Liechtenstein, and Western Balkans countries. We ignore Iceland which has no connection to the mainland and is already electricity autarkic.

2.2 Literature review

Arguments for or against electricity autarky in Europe are often supported through case studies for single municipalities (Abegg, 2011; Müller et al., 2011; Rae & Bradley, 2012; Schmidt et al., 2012) but research is needed on the European scale to understand on which level autarky is possible and to understand the land trade-offs that have to be made. Autarky based on renewable electricity is only possible if enough electricity can be generated locally, i.e. the annual potential for renewable electricity generation is at least as high as the annual demand. A sufficient potential is hence a necessary condition for autarky and as such a crucial aspect to consider when targeting autarky in any region. We acknowledge that, if the potential in an area is sufficient, autarky may still be impossible, impractical, or infeasible, for example when taking fluctuations of renewables into account. Here, we only discuss the necessary condition of sufficient potentials, but not whether autarky is actually feasible.

In the literature, different kinds of potentials have been assessed, for example: theoretical, geographical, technical, and economic. To analyse the possibility of autarky, the most important kind is the technical potential. It defines the amount of renewable energy that can be transformed to electricity given technological restrictions. There is however no consensus for this definition: in (Hoogwijk et al., 2004) for example, the technical potential does not include electricity that could be generated on environmentally protected areas, whereas in (European Environment Agency, 2009) it does. For roof-mounted PV, north-facing roof areas are sometimes included in the calculation of the technical potential (Buffat et al., 2018) and sometimes not (Defaix et al., 2012). The different definitions, but also different assumptions, can lead to diverging results.

We are not aware of studies assessing technical potentials in the context of electricity autarky on the European scale, but there are studies that assess technical potentials of single technologies in Europe. For onshore wind, results differ widely, from 4,400 TWh/a (Hoogwijk et al., 2004) to 20,000 TWh/a (McKenna et al., 2015) or even 45,000 TWh/a (European Environment Agency, 2009). The relatively low estimate of the first study can be explained by three exclusion factors not present in the latter two studies: it excludes areas with average wind speeds below 4 m/s at 10 m hub height as well as environmentally protected areas, and it limits the use of agricultural land and forests. Combined, these constraints exclude around 90% of Europe's land. Despite the differences in definitions, the three studies agree that onshore wind power could supply all of Europe's current electricity demand of around 3,000 TWh/a, assuming the technical potential could be fully exploited.

Two studies assess the technical potential of roof-mounted PV at the continental level, finding potentials of 840 TWh/a (Defaix et al., 2012) and 1,500 TWh/a (Huld et al., 2018). The difference in results can be explained by different geographical scopes, by the fact that (Defaix et al., 2012) ignores north-facing areas, and by different methods: while (Defaix et al., 2012) uses a statistical approach to quantify available roof areas, (Huld et al., 2018) uses high resolution satellite images for a few cities in Europe to derive roof area estimates, and then extrapolates these results using population density as a proxy. Both studies show that roof-mounted PV can contribute significantly to supplying Europe's electricity needs, albeit at a much lower magnitude than onshore wind. Combined with onshore wind, both technologies are likely able to fulfil Europe's electricity demand entirely.

Some of the studies with European scope disaggregate their results on the national level, thus permitting an analysis of renewable electricity potential in light of national autarky (Defaix et al., 2012; European Environment Agency, 2009; McKenna et al., 2015). Other studies have assessed the potential for single countries, e.g. wind in Germany (McKenna et al., 2014), Spain (Fueyo et al., 2010), Sweden (Siyal et al., 2015), and Austria (Höltinger et al., 2016). All of those roughly agree with the results from the analyses on the continental level and reveal potentials which are close to or exceeding today's electricity demand. Again others have assessed national potentials of roof-mounted PV, e.g. 1,262 TWh/a (Quaschning, 2000) and 148 TWh/a (residential buildings only) (Mainzer et al., 2014) for Germany or 18 TWh/a (Assouline et al., 2017) and 53 TWh/a (Buffat et al., 2018) for Switzerland. There are no such potential studies for all European countries and thus national potentials across all of Europe are available only from (Defaix et al., 2012; European Environment Agency, 2009; McKenna et al., 2015).

On the regional and municipal levels, there are some studies which assess the potentials across entire countries (Assouline et al., 2017; McKenna et al., 2014), but most studies focus on single regions or municipalities, e.g. (Bergamasco & Asinari, 2011; Brito et al., 2012; Jäger et al., 2016; Ordóñez et al., 2010; Strzalka et al., 2012). No study has been performed that assesses renewable electricity potentials on the regional or municipal levels across all of Europe within a single consistent analysis framework.

2.3 Methods and data

We assess the possibility of electricity autarky for administrative units in Europe on four levels: continental, national, regional, and municipal. For each administrative unit on each administrative level we quantify renewable potentials and current electricity demand. We then reject autarky based on renewable electricity for those units for which annual demand exceeds annual potential. We list all data sources used in this approach in Table A1 in the supplementary material.

2.3.1 Definition of administrative levels

To identify administrative units including their geographic shape on all levels we use NUTS (Nomenclature of Territorial Units for Statistics) 2013 data (eurostat, 2015) and the Global Administrative Areas Database (GADM) (GADM, 2018). The scope of our analysis is EU-28 excluding Malta (for which no data was available), plus Switzerland, Norway, and the Western Balkans countries Albania, Bosnia and Herzegovina, Macedonia, Montenegro, and Serbia. Together, all 34 countries form the continental level; in isolation they form the national level (see Table 2.1). Country shapes for EU-28 countries, Switzerland and Norway are defined by NUTS 2013, and for the Western Balkans countries by GADM.

The regional level is defined by the first-level administrative divisions, e.g. cantons in Switzerland, régions in France, or oblasti in Bulgaria, of which

GADM identifies 502 in the study area. Macedonia and Montenegro only have one subnational administrative level – the municipal level – which in our analysis is below the regional level. For Macedonia we use a statistical division from NUTS3 larger than the municipal level, and for Montenegro we use the municipal level from GADM as no alternative is available. Lastly, there are 122635 communes which form the municipal level. These communes are defined for most countries by the Local Administrative Unit 2 (LAU2) layer of NUTS 2013. For Albania, Bosnia and Herzegovina, Macedonia, and Montenegro, we take their definitions from GADM. Lastly, we estimate the size of maritime areas over which administrative units have sovereignty by allocating Exclusive Economic Zones (EEZ) to units on all levels. Within a country, we divide the EEZ and allocate parts to all subnational units which share a coast with the EEZ. The share is proportional to the length of the shared coast. We use EEZ shape data from Claus et al. (2018).

Table 2.1: Administrative levels considered in this study.

Level	Number units	Source of shape data
Continental	1	GADM (GADM, 2018), NUTS (eurostat, 2015)
National	34	GADM (GADM, 2018), NUTS (eurostat, 2015)
Regional	502	GADM (GADM, 2018), NUTS (eurostat, 2015)
Municipal	122635	GADM (GADM, 2018), LAU (eurostat, 2015)

2.3.2 Renewable electricity potential

To quantify the renewable electricity potential in each administrative unit, we first estimate the surface areas eligible for generation of renewable electricity and then the magnitude of electricity that can on average be generated annually on the eligible surfaces by on- and offshore wind turbines and open field and roof-mounted photovoltaics. We assess two types of potentials of renewable electricity: the technical potential and a socially constrained potential. The only difference between these potentials is the classification of surface eligibility, i.e. the surface areas available for renewable electricity generation. We furthermore assess land requirements when assuming electricity autarky, i.e. the amount of non-built-up land that is needed for electricity generation to become autarkic.

In our study we do not consider two types of renewable electricity that could contribute to supplying Europe's electricity demand: hydropower and biomass. We ignore hydropower, because its potential is largely exhausted in Europe

(World Energy Council, 2007) and no major new contributions can be expected in the future. We ignore biomass for two reasons: first, its power density in Europe (<0.65 MW/km^2 (European Environment Agency, 2006)) is lower than the one from wind or solar power and thus wind turbines and open field photovoltaics are always superior in terms of electricity yield per area. Second, we also do not consider combining wind power and biomass production despite the high electricity yield per area because of land use conflicts with food and feed production that biomass production causes.

2.3.2.1 Open field surface eligibility

To decide which fractions of the land and water surfaces of an administrative unit can be used for open field PV, or on- and offshore wind farms, we divide Europe into a 10 arcsecond grid, whose cell size varies with the latitude but never exceeds 0.09 km^2. For each cell we obtain the current land cover and use from the GlobCover 2009 dataset (European Space Agency, 2010), the average slope of the terrain from SRTM and GMTED (Danielson & Gesch, 2011; Reuter et al., 2007) or its maximum water depths from ETOPO1 (Amante & Eakins, 2009), and whether it belongs to an area which is environmentally protected from the World Database on Protected Areas (UNEP-WCMC & IUCN, 2018). We additionally use the European Settlement Map (ESM) with 6.25 m^2 resolution (Ferri et al., 2017) to classify an entire 10 arcsecond cell as built-up area if more than 1% of its land area are buildings or urban parks. We use land cover and use, slope, protected areas, and settlements as decision criteria because these constraints have been found to be the most relevant for land eligibility studies in Europe (Ryberg et al., 2018). For each potential type there is a set of rules by which we define if a cell is eligible for renewable electricity generation and if it is, which technology type it is used for. We assume that a cell is always used for a single technology only, based on the rules described below.

2.3.2.2 Roofs for PV

The potential for roof-mounted PV not only depends on the amount of roof area available, but also on the orientation and the tilt of these roofs. We analytically derive rooftop area in each administrative unit. We then use a dataset of Swiss roofs, taking it as representative for Europe as a whole, to correct the area estimation and to statistically amend it with tilt and orientation.

We use the European Settlement Map (Ferri et al., 2017) to identify the amount of rooftop area in each administrative unit. The map is based on satellite images of 2.5 m resolution and employs auxiliary data e.g. on population or national data on infrastructure to automatically classify each cell as building, street, urban green, etc. For each 10 arcsecond cell we sum up the space that is classified as buildings. We consider only those cells that we initially classified as built-up areas before, and which are hence not used for other renewable generation.

We then amend this first estimation with data from sonnendach.ch for Switzerland (Swiss Federal Office of Energy, 2018). We use this dataset in two ways. First, we improve the area estimation taken from the European Settlement Map. Sonnendach.ch data is based on high-resolution 3D models of all buildings in Switzerland and thus allow for estimations of roof areas with high accuracy. For the roofs included in the sonnendach.ch dataset, the European Settlement Map identifies 768 km^2 building footprints, where sonnendach.ch finds 630 km^2 roof area. Sonnendach.ch also apply expert estimation of unavailable parts of the roof, e.g. those covered with windows or chimneys (Swiss Federal Office of Energy, 2019), which reduces the theoretically available rooftop areas from 630 km^2 to 432 km^2. Thus, for Switzerland, the realistic potential may be only 56% of the building footprints from ESM. We assume this factor is representative for all Europe and apply the factor of 0.56 to all areas identified by the European Settlement Map.

The second use we make of the Swiss data is to identify the tilt and orientation of the roof areas. For that, we cluster all roofs in 17 categories: flat roofs, and roofs with south-, west-, north-, and east-wards orientation, each with four groups of tilt. We then quantify the relative area share of each category (see Table A2 in the supplementary material). Again, we assume the distribution of these attributes of the Swiss housing stock is representative for Europe and apply it to all administrative units.

2.3.2.3 Renewable electricity yield

Based on the previous steps we can quantify the surface area eligible for renewable electricity generation in each grid cell. To estimate the annual generation for wind power, we first assume a capacity density of 8 MW/km^2 (15 MW/km^2) based on a rated capacity of 2 MW/unit (10 MW/unit) for onshore (offshore) wind (European Environment Agency, 2009) which allows us to derive the installable capacity for each grid cell. We then simulate renewable electricity yield of the years 2000–2016 on a 50 km^2 grid over Europe from Renewables.ninja (Staffell & Pfenninger, 2016) to determine the average annual electricity yield from installable capacity on each 10 arcsecond grid cell. We assume onshore (offshore) wind turbines are available 97% (90%) of the time (European Environment Agency, 2009).

For open field PV and flat roof-mounted PV, we assume a capacity density of 80 MW_p/km^2 based on a module efficiency of 16% and space demand of two times the module area as an average for all Europe. Furthermore, we assume modules are installed southward facing and with tilt optimisation as defined by (Jacobson & Jadhav, 2018). For PV of tilted roofs, we assume a capacity density of 160 MW_p/km^2 based on a module efficiency of 16%. Using the statistical model from Table A2 we define 16 different deployment situations. We then use Renewables.ninja (Pfenninger & Staffell, 2016; Staffell & Pfenninger, 2016) to simulate the renewable electricity yield of the years 2000–2016 of each deployment situation on the 50km^2 grid. We assume a performance ratio of 90%.

2.3.2.4 Technical potential

We first assess the technical potential which is only restricted by technological constraints. To quantify it, we use the following rules: We allow wind farms to be built on farmland, forests, open vegetation and bare land with slope below 20° (slope constraint taken from (McKenna et al., 2015)). An example of exclusion layers for Romania is shown in Figure 2.1. We furthermore allow open field PV to be built on farmland, vegetation and bare land with slope below 10° (slope constraint taken from (Al Garni & Awasthi, 2018)). In grid cells where both onshore wind farms and open field PV can be built, we choose the option with the higher electricity yield. Lastly, we allow offshore wind farms to be built in water depths of less than 50m. Grid cells identified as built-up area cannot be used for open field PV or wind farms, only for roof-mounted PV.

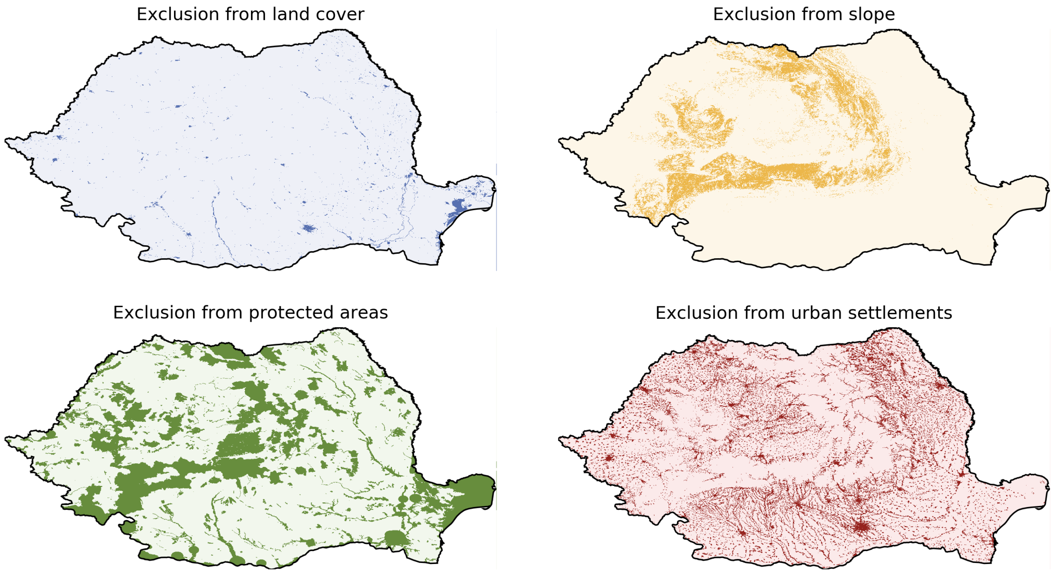

Figure 2.1: Exclusion layers for determining the potential of wind power in Romania: shaded areas are not available for electricity generation (technical potential ignores protected areas).

2.3.2.5 Technical-social potential

The technical potential defines an upper bound to the electricity that can be generated in each administrative unit. However, it is a strong overestimation of a realistic potential: in our case, it allows onshore wind and open field PV to be built on all environmentally protected areas, which might not only have severe consequences for the local flora and fauna, but may also breach the directives on habitats (Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora, 1992) and birds (Directive 2009/147/EC of the European Parliament and of the Council of 30 November 2009 on the conservation of wild birds, 2010) of the European Union in addition to national and regional laws. The technical potential also allows open field PV to be built on farmland causing land use conflicts with food and feed production, much like the problems with biomass. Finally, it permits use of all eligible surfaces, potentially leading to very high densities of electricity generation. In some parts of Europe this leads to all eligible surfaces being covered with PV modules or wind turbines, which is not realistic.

We therefore introduce a socially and ecologically constrained potential, in which we prohibit the use of environmentally protected surfaces and prohibit open field PV on farmland. Open field PV can only be built on bare and unused land. Furthermore, we assume that only 10% of all available surface area can be used for renewable power generation, including water surface for offshore wind. We do still allow the use of all eligible roof areas for the generation of solar power, as there is little conflict potential in that case. We test the impact of this assumption in the results section. Table 2.2 lists the differences in the definition of the technical potential and the technical-social potential.

Table 2.2: Differences between the technical potential and the technical-social potential.

	Technical potential	Technical-social potential
Protected areas usable	yes	no
PV on agricultural land	yes	no
Eligible land usable	100%	10%
Eligible water surfaces usable	100%	10%
Eligible roof areas usable	100%	100%

2.3.2.6 Land footprint

Finally, we assess the amount of land necessary to reach electricity autarky. This allows us to study one important implication of electricity autarky: its land foot print. Furthermore, assessing the land necessary for electricity autarky reduces uncertainty compared to assessing the technical-social potential. Quantifying the potential for every administrative unit in Europe has large uncertainties: the assessment is very sensitive to some of the assumptions which in turn may vary between regions in Europe and which are highly uncertain, in particular the amount of eligible land that can be used for electricity generation (Höltinger et al., 2016). When we assess the necessary land surface, we do not need to make this assumption: instead, it is the result of our analysis.

We assume most of the technical potential to be available but we prohibit open field PV on farmland. Because we focus on land use and to avoid making assumptions on availability of water surfaces, we ignore offshore wind potentials. We prioritise roof-mounted PV as it does not require land: first, we fulfil demand as much as possible with electricity from roof-mounted PV. Then, we compare the remaining demand to the potential of open field PV and onshore wind to derive the share of the non-built-up land that is necessary to fulfil demand with renewable electricity which is generated locally.

2.3.3 Current electricity demand

We relate the renewable electricity potential to current electricity demand. We use country-wide demand data from 2017 for each country (Open Power System Data, 2018) from ENTSO-E. For subnational levels, we allocate the national demand based on population distribution and the size and location of electricity-intensive industries. We subtract industrial demand of electricity intensive industry from national demand and assume the remainder is spatially distributed over the country proportionally to population. We hence assume that each person in each country is on average responsible for the same amount of electricity demand from non-electricity intensive industries, commerce, and households. We use the Global Human Settlement Population Grid which maps population in 2015 with a resolution of 250 m (JRC & CIESIN, 2015) in Europe and globally. It is based on national census data and population registers. With that, we define the local, annual electricity demand in each administrative unit of each administrative level.

We derive a dataset of electricity intensive industries from the European Emission Trading Scheme (ETS) (European Environment Agency, 2018). Using ETS data means we are neglecting industries in Switzerland and the Western Balkan countries which do not take part in the scheme. We consider only steel, aluminium, and chloralkali process facilities, which are individually responsible for more than 0.5% of the respective ETS activity (covering ~90% of all activity). Based on the ETS address registry and manual research, we identify the exact location of those facilities.

As there is no comprehensive and consistent dataset for industrial production, we make two important assumptions to determine each installation's production and hence electricity demand. First, we assume that the product output of each plant is homogenous, corresponding to "steel", "aluminium", etc. We do thus not differentiate between types of steel or aluminium products. Each product comes with a generic electricity intensity factor (MWh/t output) which we derive from (EAA, 2012; Ecorys, 2009; Eurochlor, 2014; Eurofer, 2015; Klobasa, 2007; Paulus & Borggrefe, 2011). Second, we assume that the production of each facility is directly proportional to its emissions: a factory emitting 10% of the ETS activity's CO_2 emissions (after all installations contributing 0.5% or less have been removed) is assumed to produce 10% of the output of all facilities in the filtered list under each ETS activity. To quantify annual European production we take industry organisation data (Cembuerau, 2015; EAA, 2012; Eurochlor, 2014; Eurofer, 2015; Paulus & Borggrefe, 2011) for the most recent year available. For chloralkali plants, we assume the lowest electricity intensity in the range given by Klobasa (2007), given the efficiency improvements (-8% intensity reduction since 2001) over the last decade (Eurochlor, 2014).

2.4 Results

2.4.1 Technical potential

On the **continental level**, the technical potential of roof-mounted PV, open field PV, and on- and offshore wind is vast: technically, these technologies could generate almost 230,000 TWh/a. This exceeds the continental demand of 3,200 TWh/a in 2017 more than 70 times. The largest contribution comes from open field PV (66%), followed by offshore and onshore wind.

On the **national level**, the technical potential exceeds demand in all countries, but the potentials and the density of demand are unevenly distributed across the continent. For example, the technical potential in Latvia exceeds demand 400 times, whereas it is only 5 times higher than national demand in Switzerland (when considering wind and solar power only, but not hydropower).

On the **regional level**, the technical potential is sufficient for almost all regions. In a few cases – the first-level administrative units with all or most of their area within densely populated city borders (Brussels, Basel, Oslo, Vienna, and Berlin) – the potential is insufficient; further, a number of cities (e.g. Bucharest, Geneva, Budapest, and Prague) have potentials only slightly higher than their demand. Hence, on this level, resource constraints start to become an issue in a few cases, but generally, the technical potential is still high enough in almost all regional cases.

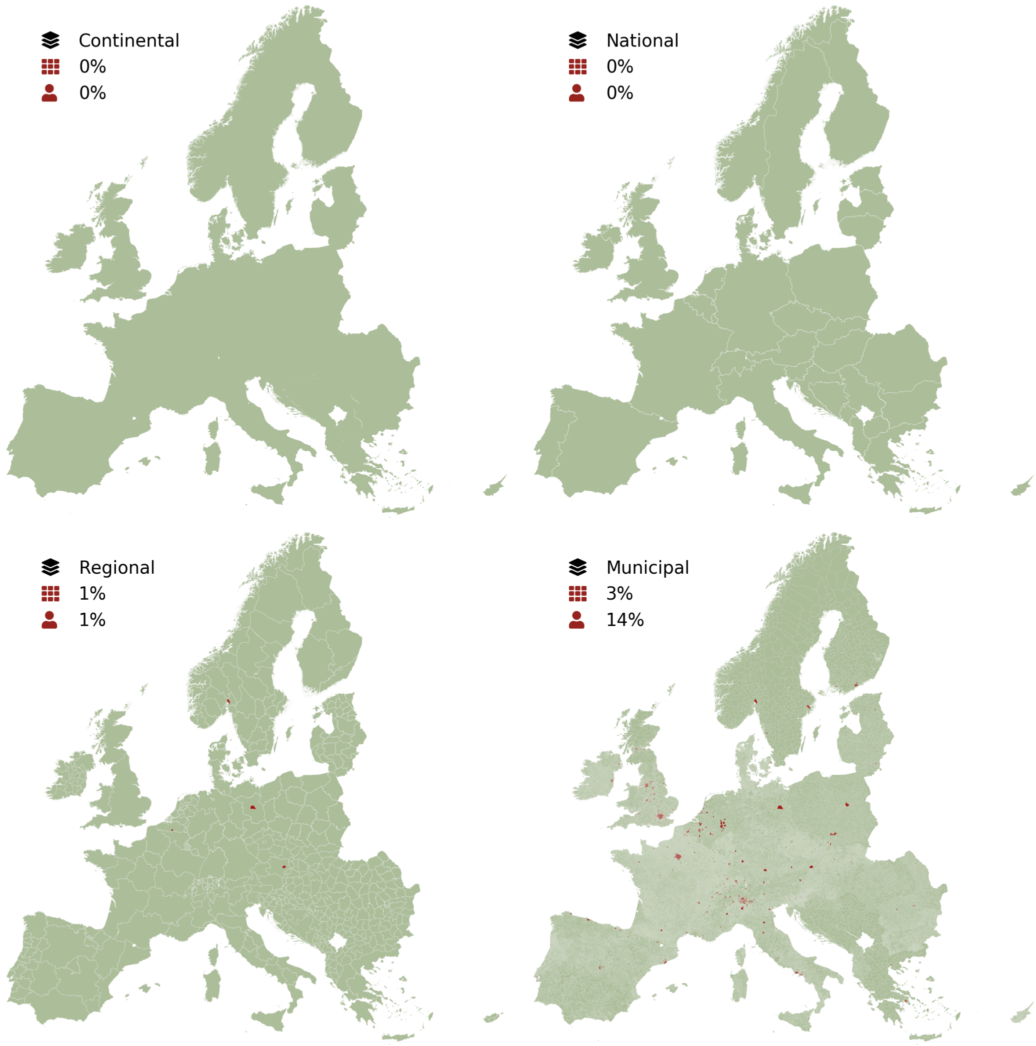

Figure 2.2: Administrative units where the technical potential exceeds electricity demand (light/green) and where it does not (dark/red), on all four administrative levels. For each level the text box furthermore shows from top to bottom: the name of the level, the fraction of undersupplied administrative units, and the fraction of the European population living in undersupplied administrative units.

Despite the vast continental potential, the **municipal level** sometimes shows technical potentials which are too small to allow for autarky. Although almost all – about 97% – of municipalities have a technical potential exceeding current demand (see Figure 2.2), about 14% of Europe's population would be undersupplied. It is largely an issue of densely populated municipalities: 98% of the impacted population lives in municipalities with a population density higher than 1000 people per km^2. Using the definition of the European Commission and the OECD of the degree of urbanisation (DEGURBA) (Dijkstra & Poelman, 2014), 91% of the impacted population lives in cities, 9% in towns and suburbs, and none in rural areas.

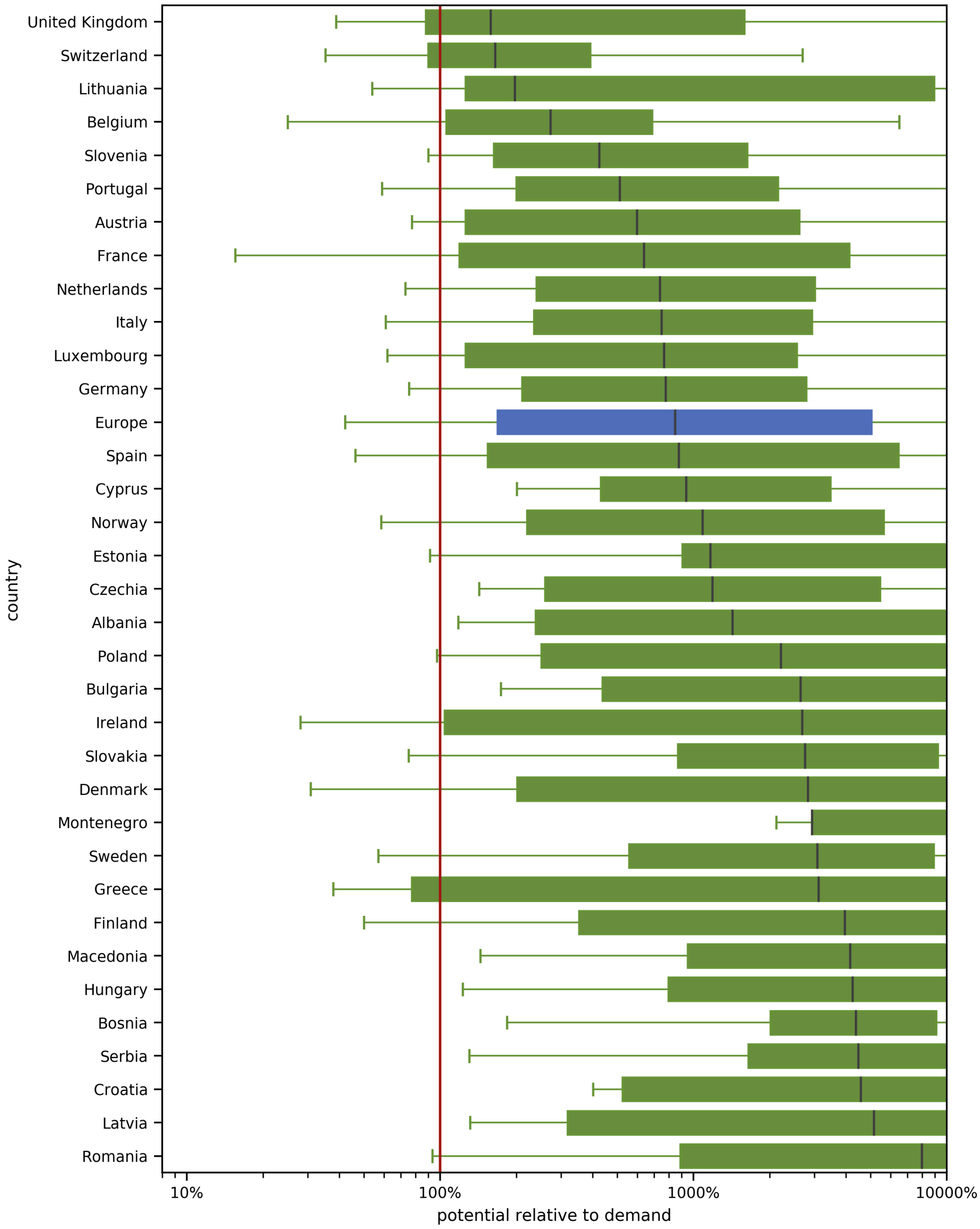

Figure 2.3: Distribution of technical potential per country and all of Europe as experienced by the population when considering autarky on the municipal level: the boxes show the potential of the municipalities in which half of the population lives; centred around the median. Whiskers (green lines) show 95% of the population. Outliers (2.5% below and above each whisker) are not depicted.

Figure 2.3 shows the ranges of relative technical potential for all countries when assuming autarky on the municipal level. It shows how some countries have better prerequisites for electricity autarky on this level than others: in Montenegro for example, almost everyone lives in municipalities with very high potential; a situation which is similar in other Balkans countries and Cyprus. Other countries like Switzerland, United Kingdom, Ireland, and Greece have a quarter of their population living in municipalities with a potential lower than or close to their current demand, making municipal level autarky impossible. The figure furthermore shows that the relative potential varies largely within countries: in Greece for example, despite the low potential it has to offer for a quarter of its population, the majority of the remaining population lives in municipalities where the potential exceeds demand 30 times. Countries with such high variability could pool resources and seek autarky for sets of municipalities – combining those with low potential with neighbouring municipalities with high potential to achieve sufficient supply for all.

2.4.2 Technical-social potential

When applying the constraints of the technical-social potential, the total potential on the **continental level** is 15,000 TWh/a and hence exceeds today's electricity demand more than 4 times. As the constraints do not limit roof-mounted PV, this is now the dominant technology (33%), followed by onshore wind, open field PV, and offshore wind. Even with strict social constraints, reducing the technical potential by over 90%, Europe's potential for renewable electricity is high enough for Europe to enable electricity autarky on the continental level.

On the **national level**, every country still has sufficient autarky potential: while the technical-social potential, similar to the technical potential, is not equally distributed over Europe, even the lowest relative potential (Switzerland) is 30% higher than national demand. Again, we find the highest relative potential in Latvia (2200% of national demand).

On the **regional level**, we find the lowest relative potentials in subnational regions within city borders. Oslo reveals the lowest potential, where less than a quarter of demand can be supplied by local renewable generation. Other urban areas also have an insufficient technical-social potential, including the Île-de-France (Paris) region, Dublin, and Berlin (see Figure 2.4). Almost all – 96% – of the 502 first-level administrative units holding 95% of Europe's population have a technical-social potential exceeding their current demand.

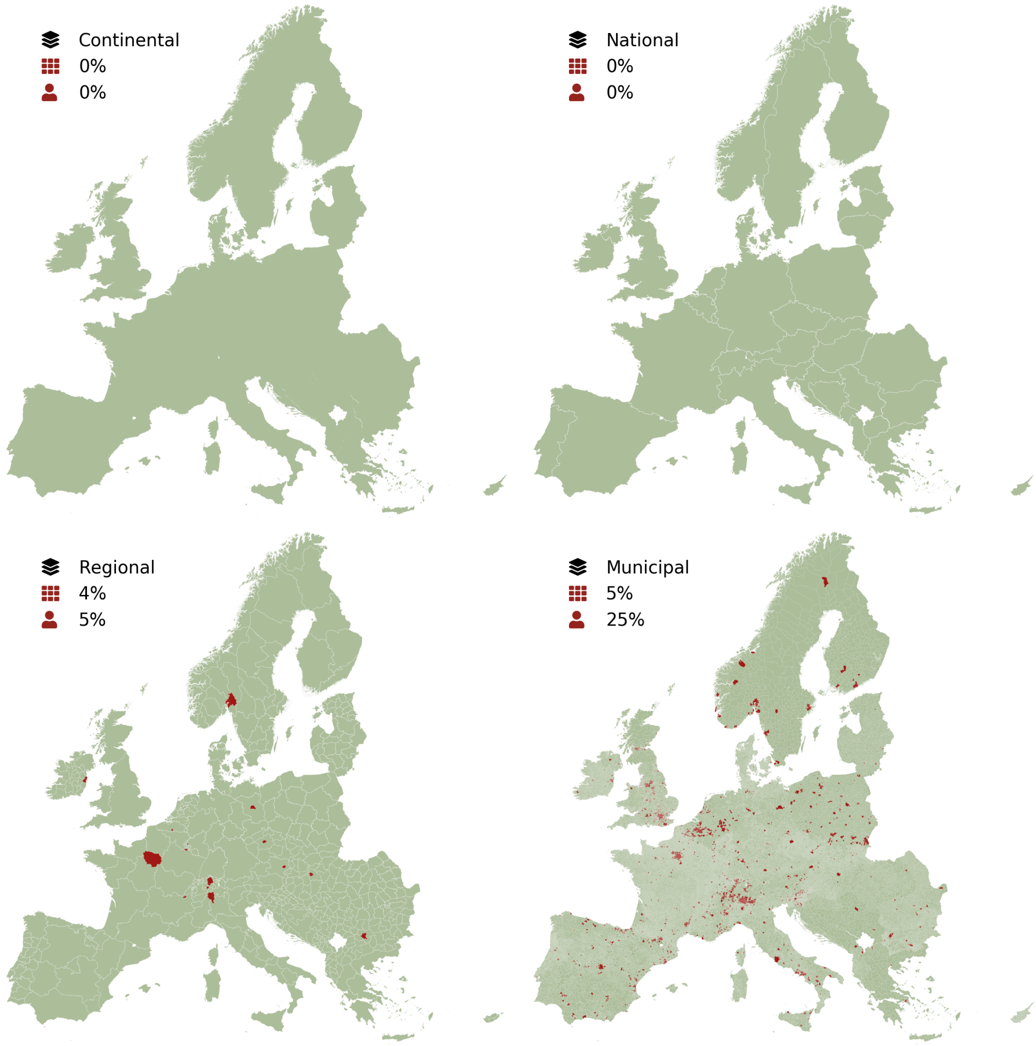

Figure 2.4: Administrative units where the technical-social potential exceeds electricity demand (light/green) and where it does not (dark/red), on all four administrative levels. For each level the text box furthermore shows from top to bottom: the name of the level, the fraction of undersupplied administrative units, and the fraction of the European population living in undersupplied administrative units.

Applying **municipal level** electricity autarky, about 75% of the population lives in the 95% of municipalities where the technical-social potential exceeds current demand. The majority of those undersupplied – 89% – live in municipalities with a population density above 1000 people per km^2. According to the DEGURBA definition, 83% of the affected population lives in cities, 15% in towns and suburbs, and only 2% lives in rural areas. In undersupplied rural municipalities, national parks or natural reserves often cover a large share of the area, making it impossible to supply even a small population with sufficient amounts of renewable electricity. A few municipalities, such as Dormanstown (UK), Fos-sur-Mer (France), or Deuna (Germany), are undersupplied because of electricity-intensive industries. Overall, however, whether the technical-social renewables potential is sufficient or not is almost exclusively a function of population density.

Figure 2.5 shows the ranges of technical-social potential for all countries when assuming autarky on the municipal level. It shows that for several countries,

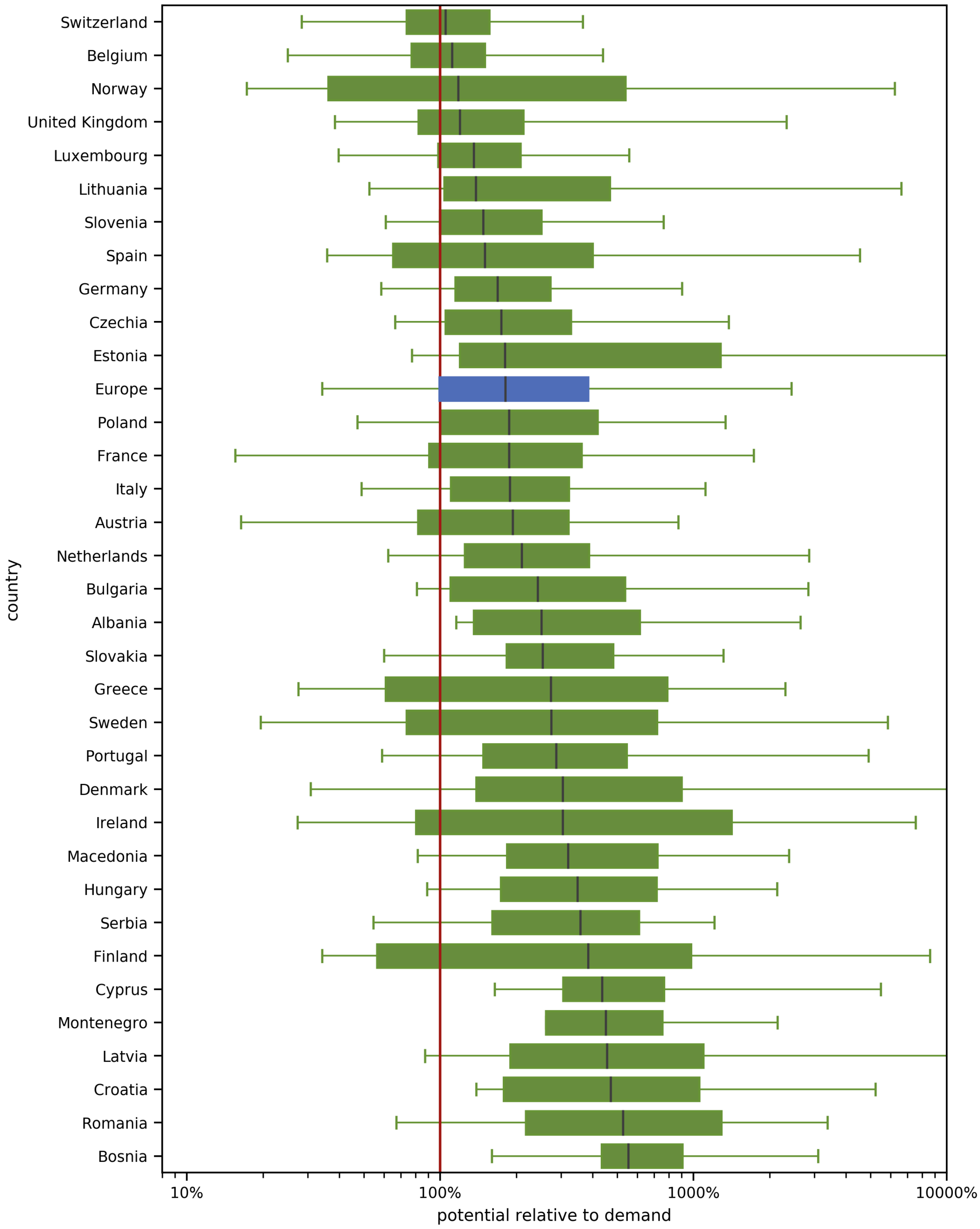

Figure 2.5: Distribution of technical-social potential per country and all Europe as experienced by the population when considering autarky on the municipal level: the boxes show the potential of the municipalities in which half of the population lives; centred around the median. Whiskers (green lines) show 95% of the population. Outliers (2.5% below and above each whisker) are not depicted.

more than a quarter of the population lives in municipalities with insufficient potential. Should the actually realisable potential be lower than the technical-social potential – for example because of public opposition – more municipalities will have insufficient potentials. The figure also shows that there are very high relative potentials in Europe, with the median person living in a municipality with a potential almost twice as high as their current electricity demand.

2.4.3 Land footprint

Results of assessing the land area necessary for electricity autarky are shown in Table 2.3. Because we prioritise roof-mounted PV, overall share of land used is generally very low: on the continental and national levels it is always smaller than 1% of the non-built-up areas. On the regional and municipal levels there are some administrative units which need all or more of their non-built-up area, but on average the share of land used is very low as well. The reason for such limited land needs is the abundant source of electricity from roof-mounted PV which is in many cases able to fulfil the annual electricity demand on its own.

Table 2.3: Fractions of non-built-up land and roof surfaces used for electricity generation and share of demand supplied by roof-mounted PV when considering autarky. Values are given as average of all administrative units per level. Roof-mounted PV is prioritised.

Level	Average land use [%]	Average roof space use [%]	Average roof-mounted PV share [%]:
Continental	0	67	100
National	0	60	95
Regional	1	57	92
Municipal	2	48	96

Many electricity scenarios for Europe foresee much lower shares of PV and roof-mounted PV (see Discussion): in (European Commission, 2016; Fraunhofer IEE, 2017; Greenpeace & EREC, 2012) for example, the share of PV is below 40%. When we consider 40% of the electricity demand as a hard limit for the generation of electricity from roof-mounted PV in each administrative unit, we obtain the results shown in Table 2.4. Compared to the unconstrained case, average share of land used is much higher on the regional and municipal level, where it increases on average by more than factor 2. For continental and national levels, it remains relatively low with only 1–2% of built-up areas needed on average, but up to 6% for single countries. Figure 2.6 visualises the share of non-built-up land used of all units on all four administrative levels when roof-mounted PV is limited to 40%. It shows how generation becomes more concentrated with smaller autarky levels, as generation moves closer to demand centres.

Table 2.4: Fractions of non-built-up land and roof surfaces used for electricity generation and share of demand supplied by roof-mounted PV when considering autarky. Values are given as average of all administrative units per level. Roof-mounted PV is prioritised, but prohibited to contribute more than 40% to the electricity demand in each administrative unit.

Level	Average land use [%]	Average roof space use [%]	Average roof-mounted PV share [%]:
Continental	1	27	40
National	2	28	39
Regional	4	28	39
Municipal	5	22	40

The availability of roof-mounted PV clearly has a major impact on the share of land used. In Figure 2.7 we show results for other maximum diffusion levels than 40% for roof-mounted PV from a population-centred perspective. The figure shows the fraction of the European population that lives in administrative units with high *electricity generation density* which we define as units where a third or more of the non-built-up area is used for electricity generation through wind turbines or open field PV. Restricting roof-mounted PV exposes larger parts of the population to generation density: the share of population living in generation dense municipalities almost doubles when roof-mounted PV is restricted to 40% compared to the unrestricted case. Furthermore, autarky on lower levels also exposes larger parts of the population to generation density: for the same 40% restriction case, the population living in generation dense municipalities is almost 10 times larger than the population living in generation dense regions; while on the national and continental levels no one is exposed to generation density.

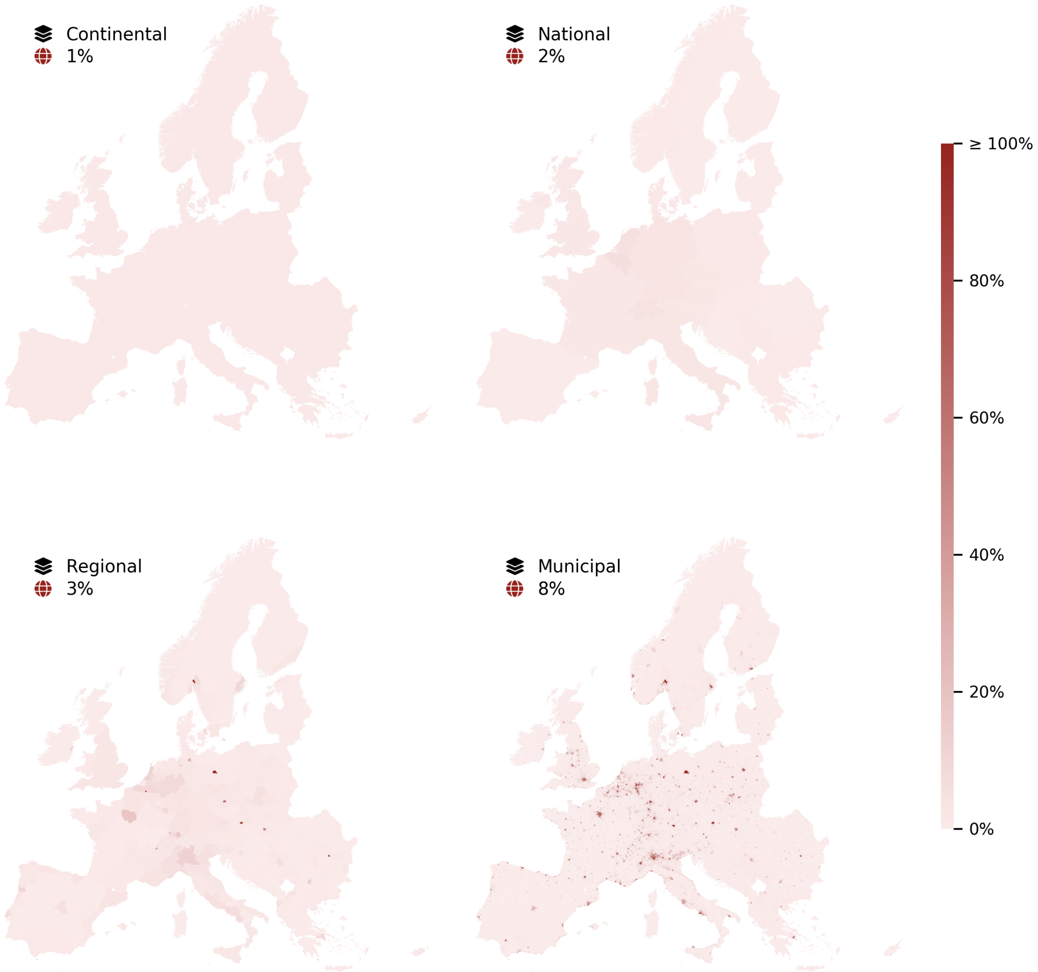

Figure 2.6: Fraction of non-built-up area needed for renewable power installations when demanding electricity autarky, for all administrative units on all four levels. The text labels on each level show the level's name and the median fraction of non-built-up area based on population. For example, at the national level, 50% of Europe's population lives in a country that requires less than 2% of its non-built-up area for renewable electricity autarky. On the municipal level, the same amount of people would see 8% of their non-built-up area used. Here, we assume farmland is not available for open field PV, we ignore offshore wind generation, and limit roof-mounted PV to 40% of demand.

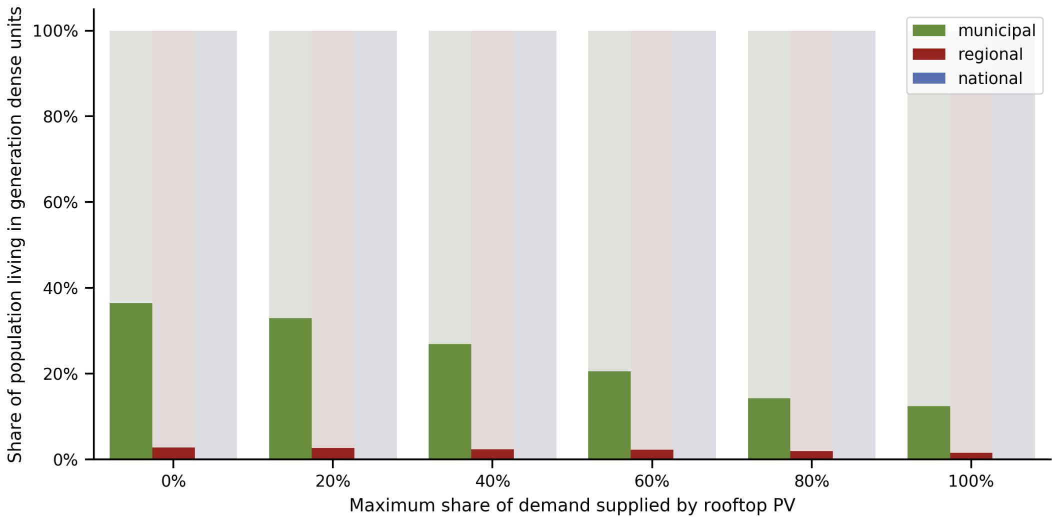

Figure 2.7: Share of the European population living in administrative units with high electricity generation density, i.e. units in which a third or more of the non-built-up land is used for wind turbines or open field PV, as a function of the maximum share of roof-mounted PV. The share is given for municipalities, regions, and countries, but is never larger than zero on the national level. For example, when a maximum of 40% of the electricity demand can be supplied by roof-mounted PV and municipalities are autarkic, almost 30% of the European population lives in municipalities in which a third or more of the non-built-up land is used for electricity generation. Total land excludes maritime regions and hence offshore wind is not considered. Roof-mounted PV is preferred over onshore wind farms and open field PV.

2.5 Discussion and conclusion

We conclude that the potential for renewable electricity – a necessary condition for electricity autarky – is high enough for Europe as a whole as well as for each individual European country to supply themselves with 100% renewable electricity, without imports from abroad. In fact, the technical potential of each of the four considered technologies alone is higher than current European demand. But in some cases, the potential is too low to satisfy current demand on the municipal or regional levels. The potential is a binding constraint especially when applying social and ecological boundaries: in this case, up to 25% of the European population would live in areas that are not supplied with enough renewable electricity when considering autarky on municipal level. Areas which are unable to become autarkic are those with high population density, where non-built-up land sparse and less roof space is available per inhabitant. Other drivers of the possibility for autarky are electricity-intensive industries and, when kept free of energy installations, environmentally protected land. Both make autarky impossible for some municipalities, but their impact on all Europe, considering all municipalities, is small.

A second key finding in our study is that although most regions and municipalities have sufficiently high potentials to supply themselves, places with high population density must use large shares, sometimes approaching or exceeding 100%, of the remaining land for electricity generation if they seek to become autarkic. Increasing the geographical scope of electricity supply greatly relieves pressure on non-built-up land – which is often already under a great deal of pressure. On these higher geographical levels, generation does not need to happen in immediate spatial proximity of demand and can either be more equally distributed across the land, and/or moved to areas with fewer use conflicts. Both findings are sensitive to the assumed dispersion rate of roof-mounted photovoltaics: large potentials of this technology will improve the situation for smaller autarky levels as demand for non-built-up land is reduced.

2.5.1 Uncertainties and future research

There are trends in the European electricity system that can have a significant effect on our results. On the one hand there are technological improvements which will increase the potential of renewable electricity and thus help facilitate autarky on lower levels too. In our study, we used optimistic wind turbine and PV system parameters, which are ahead of the current state of the art, without being bold assumptions – but technology may evolve further than we expect today and thus pave the way for more autarky. The opposite case, i.e. that future technology is worse than today's, appears highly unlikely.

On the other hand, there are divergent trends in electricity demand: energy efficiency is being pushed not only by proponents of autarky (Müller et al., 2011; Rae & Bradley, 2012) but also by the European Commission (European Commission, 2012). If current policy plans are successful, European electricity demand would decrease over time. That would increase the chances for autarky on all levels, at least from a resource perspective. However, many expect that electricity demand will increase as the heat and transport sectors are electrified (Boßmann & Staffell, 2015; Connolly, 2017). In its reference scenario for 2050 (European Commission, 2016), the European Commission projects an increase in electricity demand of 25% in the period 2015–2050, assuming already ratified energy efficiency policies only. An increasing electricity demand would complicate autarky from a resource perspective. We can only speculate which trend will be dominant: technological improvements on the supply side and energy efficiency measures on the demand side, or rising electricity demand through electrification of the heat and transport sectors. Assuming a 25% increase in demand, supply technology enhancements in particular for photovoltaics are likely to be on par if not dominant (International Energy Agency, 2010; Philipps & Warmuth, 2017), indicating that relative potentials might as well be higher in the future than those considered in this study.

The potential for renewable electricity we assessed is a necessary condition for electricity autarky, but not a sufficient one. In that sense our approach allows us to reject the possibility of autarky if demand is larger than the potential, but it does not allow us to confirm its feasibility. This means that areas for which we identified a potential higher than current demand may in fact not be able to reach autarky, because of further constraints and factors. To confirm the technical feasibility of autarky, we would have to take further technical factors into account, including distribution and transmission grid constraints, grid service requirements, and balancing of fluctuating renewables. Temporal fluctuations of renewable electricity can be balanced by spatial smoothing through larger grids or by temporal smoothing through storage – a point raised by critics of autarky electricity schemes (see Introduction). Importantly, we did not consider the problem of balancing, on both short and seasonal time scales, but this will greatly impact the feasibility of autarky on different levels.

We furthermore did not consider economic restrictions and instead used all of the available wind and solar resource, independent of its quality and cost. While solar and wind power generation is possible in most parts of Europe, they are expensive in many places, especially where the wind or solar resource is low. Hence, a realistic economic potential will be lower than the technical-social potential we used. Further, the method of balancing fluctuating renewable generation will contribute to total costs and the reduced potential of spatial balancing on lower geographical levels may complicate the feasibility of autarky. For our analysis, cost aspects were not relevant, but they must be considered by any analysis that confirms feasibility of electricity autarky in a certain area.

The third, and likely most uncertain type of restrictions are socio-political – in particular public and political acceptance of renewable power projects and grid expansion (Höltinger et al., 2016). Not only is the impact of acceptance difficult to assess generally, but also it may vary drastically between different parts of Europe depending on local preferences and the style of decision-making, and it may vary over time. However, our main findings are not sensitive to this type of uncertainty. We show the relative difference between administrative levels which is largely driven by the geographic scale of each administrative level and the population distribution – a finding that is unaffected by any further social or economic constraints.

2.5.2 Policy implications

While renewable electricity resources are abundant in Europe, electricity autarky below the national level is not possible everywhere: some regions and municipalities have insufficient potential or need large fractions or all of their non-built-up land to become autarkic. A workaround for this issue could be to form electricity regions in which urban areas cooperate with their surrounding municipalities. In such electricity regions the surrounding municipalities could generate surplus electricity and export it into cities. The necessary size of such electricity regions is unknown and depends on the current and maximum density of the surrounding municipalities.

Even if forming electricity regions is an option, our results show how they would lead to high generation density in and around the urban area as autarky requires supply to be in close spatial proximity of demand. Even without electricity generation, these metropolitan areas are already under high pressure on non-built-up land and electricity generation would cause further pressure and potential land use conflicts, possibly aggravating any opposition against renewables and constraining their feasible expansion potential. Electricity autarky on the national level or above permits generating electricity relatively further away from demand. Electricity generation can hence be distributed more freely, but at the expense of the experienced freedom and local value creation that more local autarky is seen to hold the potential for.

Very high shares of building integrated PV, for example by using all rooftops for electricity generation, and/or by additionally using the façades of buildings, and/or by technological improvements and higher efficiencies would enable autarky also on regional and municipal levels, but only assuming balancing issues of electricity systems with very high PV shares, in some cases exceeding 80% can be handled. No study has investigated such extreme PV scenarios for all of Europe, but case studies have already shown this to be difficult for single regions and we expect that balancing costs would be high, if it would at all be feasible to store such vast amounts of solar electricity from summer to winter.

Instead, our results show that large shares of demand can be covered by locally generated renewable electricity, in all countries, regions and most municipalities of Europe. Full autarky, i.e. without any trading between areas, is not possible in the most densely populated regions, and hence a non-trivial share of the European population would be undersupplied if their municipality, and in a few cases, their region, declared itself electricity autarkic. In many areas, especially in and around larger cities, autarky is possible from a resource perspective, but it would come at the cost of high additional pressure on as yet not built-up land. Here, we have shown in which parts of Europe autarky would be at all possible and where not. Whether and where this is really attractive is a still open question.

3 Trade-offs between geographic scale, cost, and system design for fully renewable electricity in Europe

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Abstract

Renewable electricity resources are abundant across Europe, and the potential is sufficient to enable full electricity sector decarbonisation on different scales, from the regional to the continental, with self-sufficient or interconnected units. We show that a continental-scale, fully renewable electricity system is cheapest, but also that national- and regional-scale supply systems are possible at cost penalties of 20% or less. The key to low cost is transmission, but it is not necessary to vastly expand the transmission system. When electricity is transmitted only to balance fluctuations within national or regional net self-sufficient supply units, transmission needs are comparable to today's. The largest differences across system designs concern land use and thus social acceptance: in the continental system, generation capacity is strongly concentrated on the European periphery where the best resources are, necessitating large transmission expansion. Regional systems, in contrast, have more dispersed generation near demand, where land-use pressure is already high. The key design trade-off for a fully renewable European electricity supply is therefore not the effect of geographic scale on system cost, but the effect of geographic scale on the spatial distribution of required generation and transmission infrastructure.

3.1 Introduction

To fulfil its commitment under the Paris climate agreement, Europe must eliminate electricity sector emissions. For this, future electricity supply will be based largely, or entirely, on renewable sources (IPCC, 2018). Although ambitious, this is possible because solar and wind generation technologies are mature (T. W. Brown et al., 2018; IRENA, 2019), their generation potential is sufficient (Bódis, Kougias, Taylor, et al., 2019; Jacobson et al., 2017; McKenna et al., 2015; Ruiz et al., 2019;

Tröndle, Pfenninger, & Lilliestam, 2019b), various options are available to balance variable renewable generation on time scales ranging from hours to years (T. W. Brown et al., 2018; Grams et al., 2017; Luo et al., 2015; Rasmussen et al., 2012; Schlachtberger et al., 2017), and systems relying on them can have similar cost as today's system (T. W. Brown et al., 2018; Bussar et al., 2014; Child et al., 2019; Connolly et al., 2016; Jacobson et al., 2017; Pleßmann & Blechinger, 2017). As renewables are abundantly available across the continent, very different kinds of future electricity system designs are possible, from a Europe-wide electricity grid sharing generation resources among all countries, to myriads of locally self-sufficient units, either disconnected or with limited interconnection, as well as combinations of these two extremes (Battaglini et al., 2009; Blarke & Jenkins, 2013). Here, we investigate the impact on cost and cost-optimised system design of decarbonising Europe's electricity supply using renewables on different geographic scales and with different degrees of self-sufficiency.

The European energy transition is highly politicised and citizen engagement is one of its historical drivers (Lilliestam & Hanger, 2016). Ideas of decentralisation, energy democracy, and local control have great appeal to many citizens and decision-makers, leading to calls for regionally self-sufficient systems based on local resources (100% RES Communities, 2015; Friends of the Earth et al., 2018; Scheer, 2012; Schmidt et al., 2012). In such systems, generation variability would be balanced locally using electricity storage and locally available dispatchable resources, without the need for new transmission infrastructure. The annual renewable potential for local self-sufficiency is large enough in most of Europe (Tröndle, Pfenninger, & Lilliestam, 2019b), but it is not known how balancing of fluctuations on smaller time-scales affects cost and the system design in different regions.

Proponents of a continent-spanning supply system, in contrast, point to the cost-reducing impact of sharing the best renewable resources and of relying on stochastic smoothing of supply fluctuations through large grids, while making efficient use of dispatchable resources regardless of where they are located (Benasla et al., 2019; Dii, 2012; Grams et al., 2017; Mano et al., 2014; Patt et al., 2011). Indeed, previous research has shown that these effects make a continent-spanning renewables-based system cheaper than smaller systems (Brown et al., 2018; Schlachtberger et al., 2017; Schmid & Knopf, 2015).

Previous work however changed system designs along two dimensions simultaneously: supply scale and balancing scale. We define supply scale as the geographic extent within which systems are net self-sufficient, and balancing scale as the geographic extent within which net self-sufficient systems can balance renewable fluctuations. By varying both simultaneously, past work is unable to attribute increasing cost and decreasing transmission requirements to access to better renewable resources, access to dispatchable resources, or stochastic smoothing in large grids. It is furthermore not clear whether self-sufficiency is necessarily more expensive in smaller than larger systems. Indeed, it seems possible that the cost penalty of smaller-scale self-sufficiency can be mitigated through appropriate system design.

Here we model fully renewable European electricity systems and vary supply scale and balancing scale independently across continental, national, and regional levels. This allows us, for example, to consider net self-sufficient regional electricity systems which use the entire continent to balance their local supply. We use a cost-minimising linear programming model that considers solar, wind, hydropower, and bioenergy, based on the *Calliope* framework (Pfenninger & Pickering, 2018). It is spatially resolved to first-level administrative divisions (497 regions) and runs at a 4-hour temporal resolution. We also conduct a sensitivity analysis based on a multi-fidelity sparse polynomial chaos expansion of the original model, permitting us to explore a large range of uncertainties despite the main model being computationally difficult to solve (see Section 3.7).

3.2 System scale drives system cost

We first assess the impact of three different system scales on total system cost and find that there is a strong trade-off between balancing scale and cost, but only a weak trade-off between supply scale and cost (Figure 3.1). As expected,

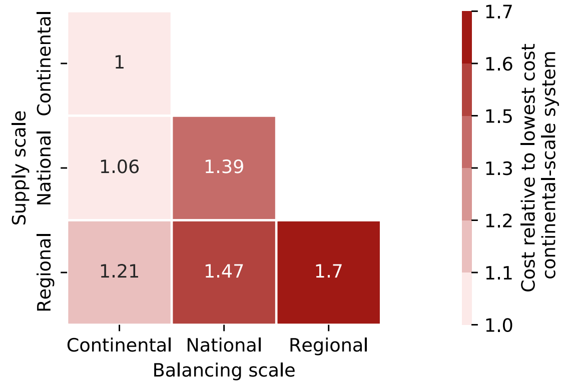

Figure 3.1: System cost of six electricity systems in Europe with supply and balancing of supply on three different scales, relative to lowest cost, continental-scale system. In all six cases, net supply is generated (x-axis) and balanced (y-axis) either on the entire continent, within countries, or within regions. Systems on the diagonal are entirely continental, national, or regional scale with no trade between units on the respective scale. Systems below the diagonal are net self-sufficient (zero trade balance over a whole year) on their respective supply scale with trade for balancing between units on this scale.

system cost increases when either supply or balancing scale decreases. System scale matters mainly because interconnecting a wider geographic area allows dispatchable generation options such as hydropower and bioenergy to percolate across the entire European system, lowering the total balancing cost. Further, a geographically larger supply system covers a greater geographic area, and thus a greater variety of wind and solar resources, including higher-quality ones out of reach in smaller-scale cases. For an entirely continental-scale system, in which supply and balancing of supply spans the entire continent, the cost-optimised system configuration corresponds to about 0.05 EUR per kWh of electricity demand, which is comparable to today's cost. Limiting the net supply options to those available within countries or regions increases cost relative to the continental case to 106% and 121%. When we additionally decrease the balancing scale to the national level, reaching 33 isolated national systems, the costs sharply increase to 139% (national supply and balancing) and 147% (regional supply, national balancing). With balancing of supply on the lowest scale, i.e. disabling electricity trade between the 497 now isolated regions in Europe, raises cost to 170% of the continental case (Figure 3.1). The main cost driver of these small, isolated systems is the limited access to regionally concentrated balancing options like hydropower, but also the impossibility to share the best wind and solar resources among regions. Allowing for net imports hardly affects cost (see Appendix B2), again emphasising that balancing rather than supply resource quality is the main source of cost reduction in larger systems. Therefore, local electricity generation must not be substantially more expensive than a continental-scale supply, if such regionally net self-sufficient units are interconnected through the transmission grid to balance the fluctuating renewable generation.

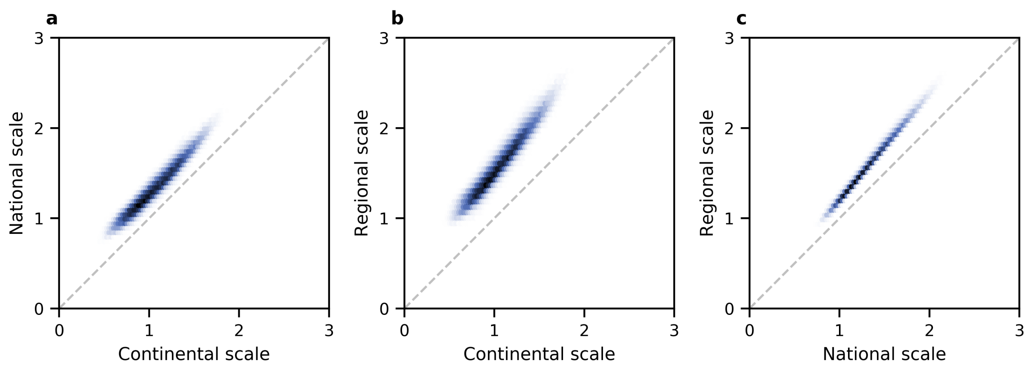

Figure 3.2: Uncertainty of system cost in electricity systems of all scales considering uncertainty in twelve input parameters. a,b,c, Bivariate histograms of the joint distributions of variability within entirely continental- and national- (**a**), entirely continental- and regional- (**b**), and entirely national- and regional-scale systems (**c**). For each scale, 100,000 samples are obtained with surrogate models fitted to the main optimisation model. Darker colours indicate more occurrences of values within these 100,000 samples. System cost is normalised by the cost of the continental base case (Figure 3.1). For a detailed description of all assessed input uncertainty, see Table B1.

The relationship between system scale and cost is unaffected by cost uncertainties. When varying input cost assumptions using surrogate models fitted to the main optimisation model (see Section 3.7), the resulting cost differences between system scales vary, but the entirely continental-scale system is always cheaper than the entirely national-scale system, which in turn is always cheaper than the entirely regional-scale one (Figure 3.2).

3.3 System scale drives technology deployment

Geographic scale strongly affects the deployment of generation, transmission, and storage technologies with respect to both total amount and type of capacity deployed. Systems with supply and balancing on small scales require more generation capacity than larger-scale ones (Figure 3.3a), as they must often rely on poorer local renewable resources to meet their annual demand. Entirely regional-scale systems rely more on solar than on wind, as solar resources are more evenly distributed across the continent than wind resources. These systems thus require more installed capacity than the entirely continental-scale system does, while their potential renewable generation is slightly lower (Figure 3.3a,d). This additional generation capacity investment needed in smaller-scale systems is one driver of their higher system cost.

Another driver is that different system scales rely on completely different structures of flexibility provision to balance intermittent generation. The entirely continental-scale system primarily relies on the transmission grid to balance fluctuations, often across large distances, with a grid expansion to about 400 TWkm (Figure 3.3c), roughly two times the current European transmission system (ENTSO-E, 2019b). Using this capacity, about 3,000 TWh/year of electricity crosses country borders, which is roughly four times current cross-border electricity flows and is comparable to the entire European electricity demand (ENTSO-E, 2019b). Of those 3,000 TWh, roughly half remain as net imports within countries, which is more than seven times the amount of today (ENTSO-E, 2019b).

Because they use the transmission grid to connect and balance resources, larger electricity systems require less dispatchable generation, storage, and curtailment than smaller-scale systems (Figure 3.3). Larger systems generate the majority of their renewable electricity from onshore wind resources for two reasons. First, the cost of onshore wind at the best locations in Europe is very low and, with a continental grid, these excellent wind resources can be used across the continent. Second, continental systems can exploit wind patterns across Europe on multiple timescales, thereby strongly reducing aggregated wind fleet fluctuations and the need for additional balancing. This effect has been confirmed previously (Grams et al., 2017; Kempton et al., 2010), and is substantially smaller for photovoltaics (Grams et al., 2017).

The identified system designs are based on systems with supply and balancing on the same geographic scales. To attribute the system effects to either supply or balancing, we keep the balancing scale constant and assess system designs on smaller supply scales (black bars in Figure 3.3). As expected, supply scale mainly affects the supply side of the system: decreasing scales increases total generation capacity, and especially solar capacity. However, it also leads to significantly smaller transmission capacities. The flexibility side, i.e. capacities of bioenergy, battery, and hydrogen, is largely unaffected by variations in the supply scale and mainly driven by balancing scale. These relationships explain the cost-increasing characteristics of both scales and their differences. Additional flexibility necessary on small balancing scales is more costly than additional supply necessary on small supply scales.

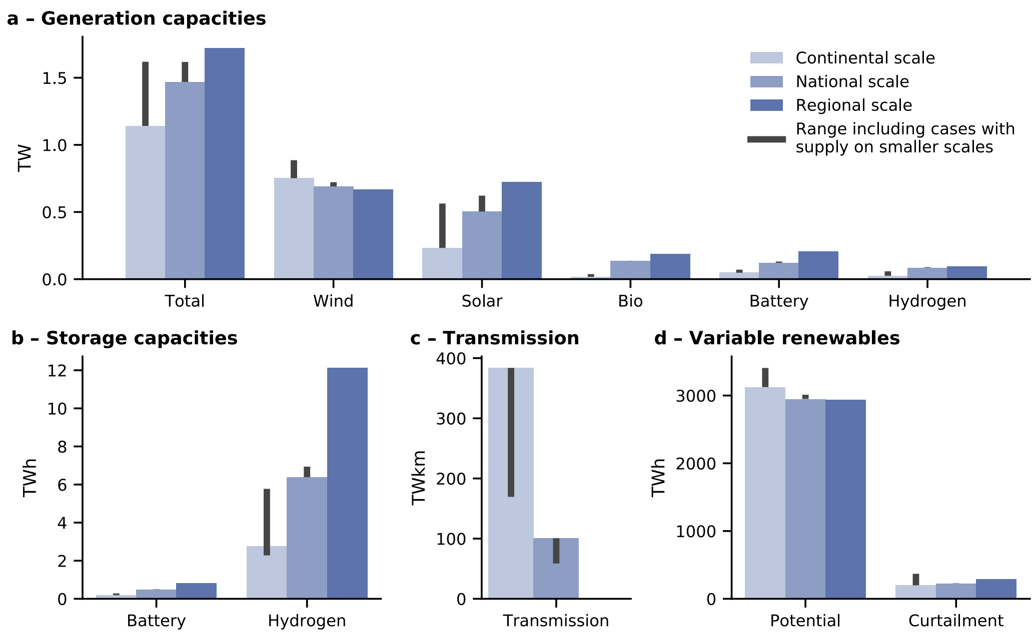

Figure 3.3: Cost-optimised technology mixes for all cases. a,b,c,d, Europe-wide installed generation capacities (**a**), storage capacities (**b**), transmission capacities (**c**), and potential and curtailed generation from variable renewable sources (**d**) for entirely continental-, national-, and regional-scale electricity systems with minimal system cost. The thin bars indicate the range of values including cases with supply on smaller scales. See Tables B2 and B3 for numerical results of all cases. **a**, The total excludes all storage capacities but includes capacities of hydropower which we keep constant in all cases (36 GW run of river, 103 GW reservoirs). **b**, Europe-wide installed storage capacities for battery and hydrogen storage. 97 TWh from hydro reservoirs and 1.3 TWh from pumped hydro storage are kept constant in all cases and not shown. **c**, Europe-wide installed electricity transmission capacities, ignoring transmission capacities within regions. **d**, Europe-wide potential generation and curtailed generation from the variable renewable sources solar, wind and hydro.

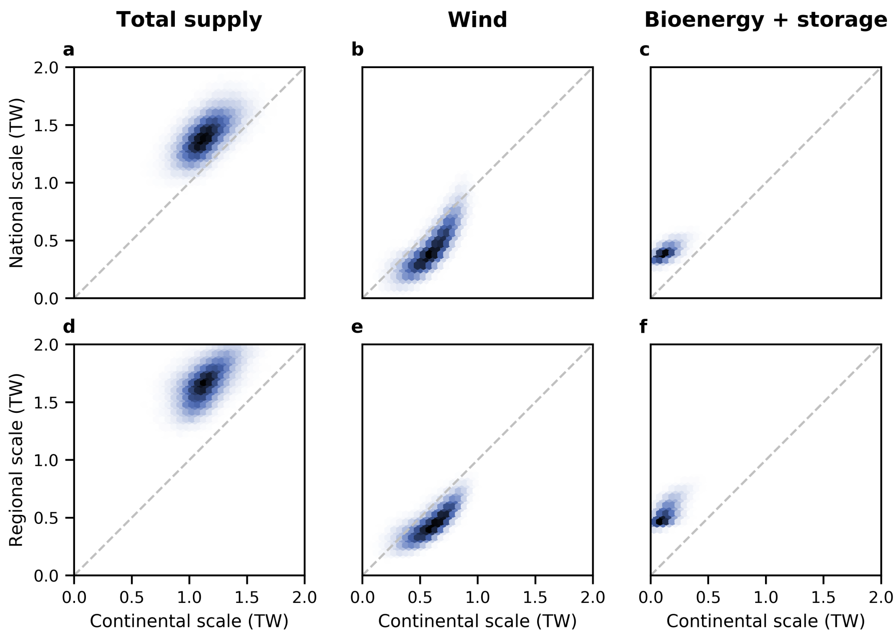

Figure 3.4: Uncertainty of installed capacities in electricity systems of all scales considering uncertainty in twelve input parameters. a,b,c,d,e,f, Each panel shows a bivariate histogram of the joint distribution of variability within entirely continental- and national- (**a,b,c**), and entirely continental- and regional-scale systems (**d,e,f**). Darker colours indicate more occurrences of values within 100,000 samples of each surrogate model. **a,d,** Variability of total supply capacity comprising wind, solar, hydro, and bioenergy capacities. **b,e,** Variability of onshore and offshore wind capacity. **c,f,** Variability of bioenergy, short-term storage, and long-term storage capacities. For a detailed description of all assessed input uncertainty, see Table B1.

The differences in system structure and capacity deployment between continental-, national-, and regional-scale systems are unaffected by input uncertainties (Figure 3.4 and Table B1). Cost-optimised entirely national- and regional-scale systems always have more combined bioenergy and storage capacity, and almost always have more total supply capacity and less wind power capacity than cost-optimised entirely continental-scale systems.

3.4 System scale drives spatial distribution of technology deployment

Expanding renewables using a continental-scale supply is the least-cost option, but doing so means that generation and transmission are unequally distributed across Europe. In the continental-scale supply system, peripheral regions generate electricity for the central parts of the continent. For example, Ireland, Lithuania, Estonia, and Albania generate more than 400% of their own electricity demand, requiring a land area 4 times larger than necessary for their own needs. This effect is even more pronounced in single regions: several Irish counties facing the Atlantic ocean – like Mayo, Kerry, or Cork –, the Baltic Sea islands Gotland and Saaremaa, or Tulcea at the Romanian Black Sea coast generate over 50 times their own demand, with the rest being exported (Figure 3.5a). In contrast,

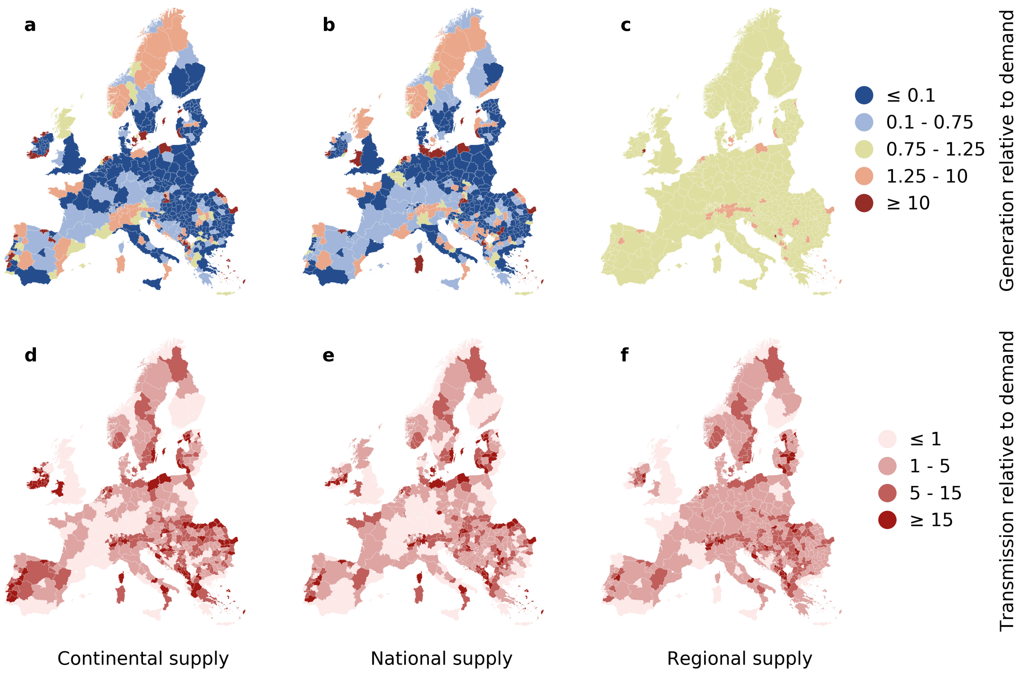

Figure 3.5: Spatial distribution of generation and transmission relative to demand for each region in Europe in three systems with continental-scale balancing. a,b,c, Electricity generated using a continental-scale (**a**), national-scale (**b**), and regional-scale (**c**) supply. **d,e,f** Electricity transmitted using a continental-scale (**d**), national-scale (**e**), and regional-scale (**f**) supply. All values are relative to local electricity demand.

other regions and countries rely strongly, or sometimes entirely, on imports: Belgium, Czech Republic, and Germany, for example, produce less than 10% of their own electricity demand. The spatial distribution is sensitive to cost and resource assumptions, as minimisation moves the bulk of generation to locations with best conditions, even if the difference to the second best location is minor; yet, the finding that generation capacity is centralised in the continental-scale supply system is robust.

To enable this trade, a continent-spanning transmission system is needed. In extreme cases, over 250 times the local demand is transferred through a region, for example in southern Ireland, where electricity from coastal wind farms is transferred to Wales and then onwards to England and central Europe (Figure 3.5d). Similar effects are found in peripheral regions in the Baltic Sea region, Portugal, Romania and the Western Balkans. Large amounts of electricity are exported from and through these regions, requiring correspondingly large transmission capacities from which most citizens do not benefit directly, raising questions of the social acceptability of such schemes.

Generation and transmission are more homogeneously distributed for national-scale (Figure 3.5b,e) and regional-scale (Figure 3.5c,f) supply. In the national case,

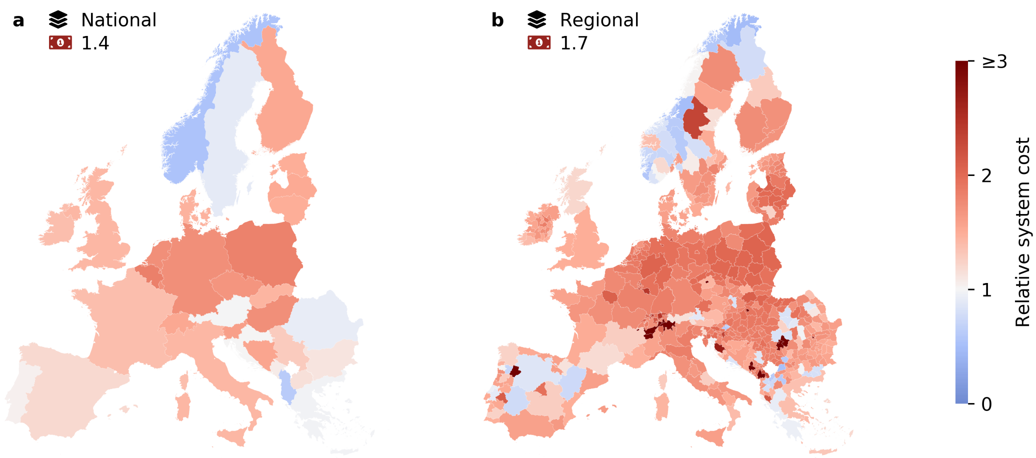

Figure 3.6: Spatial distribution of system cost normalised by demand for entirely national- and regional-scale systems, relative to the European average of the least-cost, entirely continental-scale case. Each panel shows the Europe-wide relative system cost beneath the panel heading. **a**, Relative system cost for each country in the entirely national-scale system without any exchange of electricity between countries. **b**, Relative system cost for each region in the entirely regional-scale system without any exchange of electricity between regions.

most generation hot spots remain, but their extent is smaller as they only supply national, not continental, demand. In the regional case, the generation pattern changes radically as each region generates electricity to cover its own demand only. Some regions have slightly higher generation capacities which are used to compensate for transmission losses between regions. The transmission pattern does not change as strongly because transmission remains crucial to balance renewable fluctuations. However, transmission hot spots are much less pronounced as transmission is distributed more homogeneously. National- and especially regional-scale supply thus lead to higher regional equity in terms of generation and transmission infrastructure.

In entirely small-scale systems, when regional electricity systems are fully self-sufficient and thus isolated, regional generation infrastructure equity is highest, but system cost varies strongly between regions, depending on the available renewable resources (Figure 3.6b). About 10% of regions (and a few countries) have cost below the European average of the continental-scale baseline (blue regions in Figure 3.6). These regions cover 40% or more of their peak demand with low-cost hydropower, which we assume is fully depreciated, with only O&M cost in our model (see Section 3.7).

Another 10% of regions have cost at least twice those of the least-cost European average, and for half of them, cost is at least four times higher. These expensive regions have either excessively large (existing) hydropower capacities, or low or no potential for wind power.

Because we force hydropower capacities to exist where they exist today (see Section 3.7), regions with hydropower generation greatly exceeding local demand have high supply cost due to high fixed cost for operation and maintenance. This is the case for several mountainous and rural regions, in the Alps (e.g. Grisons, Valais, Valle d'Aosta) but also elsewhere, such as Nikšic in Montenegro or Jämtland in Sweden. This is an artefact of our regional-scale analysis: these large hydro capacities were built to power nations, not small, sparsely populated parts of these countries (see Appendix B3 for a discussion of the impact of our hydropower model choices on our results).

Several regions, mainly city regions like Geneva, Prague, Budapest, and Bucharest, have low or no potential for wind power and thus their main source of electricity is the sun. As solar generation has strong seasonal fluctuations in Europe, these regions require more flexible generation from bioenergy or hydropower, or long-term electricity storage to cover winter demand. Where the potentials for wind are low, the cost of providing flexibility, and thus system cost, is particularly high.

3.5 Technology cost drives relative attractiveness of scales

Above (Figures 3.2 and 3.4), we showed how the qualitative differences between scales are robust to input uncertainty. Nevertheless, uncertainties in model inputs affect both the cost and system design in all cases. Through a global sensitivity analysis, we find that the uncertainties of three input parameters explain by far most of the uncertainty in cost and design differences between entirely continental- and national-scale systems: discount rate, overnight cost of bioenergy, and overnight cost of onshore wind power (Figure 3.7). Uncertainties regarding the other parameters hardly affect our results. Because we use a different sensitivity analysis method on the regional scale compared to the national and continental scales (see Section 3.7) we cannot analyse sensitivities of scale differences involving the regional scale (see Figures B2, B3, and B4 for sensitivities on all scales).

Entirely national-scale systems become relatively more cost-attractive when discount rate or overnight cost of onshore wind power is high. High discount rates lead to high cost of transmission lines due to their long lifetime. Similarly, high wind power cost causes lower deployment of wind capacity and therefore reduced usefulness of transmission lines. Consequently, a cost-optimised continental-scale system contains less transmission capacity in these cases and in fact resembles national-scale systems more closely. Cost and design differences between the continental and national cases decrease. In contrast, when cost of bioenergy is high, national-scale systems become relatively less cost-attractive, as seasonal fluctuations are more pronounced on the national scale, and generally bioenergy is the least-cost option to balance them. Increases in cost of bioenergy thus increases total system cost of the national-scale systems more strongly than cost of the continental case. All three parameters do not change the qualitative relationship between geographic scale, cost, and design, but they do change the magnitude with which costs and designs differ across scales.

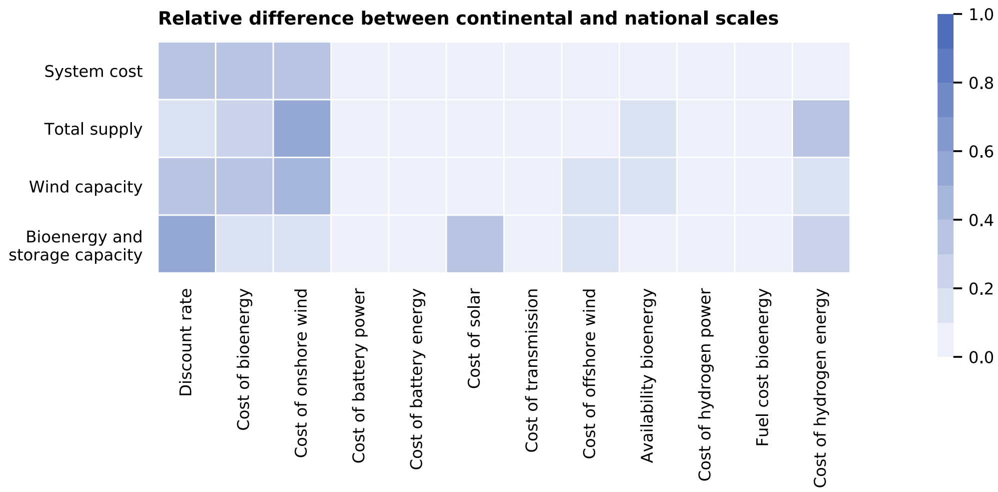

Figure 3.7: Total Sobol' indices for combinations of all considered input uncertainties (x-axis) and output differences between entirely continental- and national-scale systems (y-axis). The total Sobol' indices determine the magnitude with which the variability of one model input explains the variability of one model output given assumptions on input variability. The x-axis shows the twelve input parameters included in the uncertainty analysis, sorted by their impact on system cost. The y-axis shows the model-wide result variables for which continental to national scale differences are compared. See Table B1 for a detailed compilation of all considered input uncertainty. See Figures B2, B3, and B4 for total Sobol' indices, first-order Sobol' indices, and the difference thereof, for all relevant model outputs on all three scales.

3.6 Discussion and conclusions

We show that European renewable electricity systems on larger geographic scales always have lower cost, especially as they have more flexibility options available to balance fluctuating supply, but that small-scale supply can be designed to have only small cost penalties by allowing continental-scale balancing. Regionally self-sufficient systems have high cost, mainly because they cannot access the grid and dispatchable resources elsewhere for balancing. This is why regional net self-sufficient systems, which supply their own electricity but trade with other regions and countries for balancing, have low cost: the fluctuations are smoothed via the grid, and they can access dispatchable resources outside their own territory.

Hence, a continental-scale renewable electricity system is the least-cost option, but regional-scale supply can also be low cost, if allowing for continental-scale balancing.

This means that large and small systems need not differ much in cost, but they differ strongly in system structure and the infrastructure requirements making land-use and the physical appearance important trade-offs to geographic scale. Using the transmission grid for continental-scale supply, i.e. transmitting electricity from Europe's best resources to demand centres, has the lowest cost but requires large transmission capacities of up to two times today's transmission grid. Using the transmission grid for continental-scale balancing of net self-sufficient regional supply, in contrast, requires much less transmission capacity – roughly the size of today's transmission system. Regional-scale supply, however, has much higher generation capacity needs than continental-scale supply, and all of this generation is necessarily located near demand centres and cities, where pressure on land is already high. Hence, by scaling the European electricity system on the supply and balancing side independently, very different renewable electricity system designs are possible. While systems with continental-scale balancing all have similar costs, they differ strongly regarding how much and where transmission and generations assets are needed.

By applying a multi-fidelity sparse polynomial chaos expansion to our high-resolution electricity system model, we show that the findings are unaffected by the input parameter uncertainty we consider. However, the cost outlook for specific technologies influences the relative cost differences between larger-scale and smaller-scale systems. Two aspects which our analysis does not consider may make small-scale systems more cost-attractive. First, additional flexibility deriving from electrifying the heat and mobility sectors could reduce the cost of flexibility, which in our model is particularly high on small scales. Second, ancillary services that must be provided locally could limit the otherwise unrestricted spatial deployment on the continental scale. Both aspects have the potential to reduce cost differences between systems designed for different scales. For a detailed discussion of the effects, see Appendix B4.

We show that fully renewable electricity supply in Europe does not necessarily require vastly increased transmission capacities, contradicting recent statements and views (Joskow, 2019). By allowing regional-scale supply systems to balance supply within a continental grid, their cost penalty is reduced to 20% above the least-cost, continental-scale supply but without the need for large transmission expansion. We further show that a fully renewable electricity supply is possible not only in continent-spanning designs, as past work has shown (Bussar et al., 2014; Hörsch & Brown, 2017; Jacobson et al., 2017; Schlachtberger et al., 2017; Zappa et al., 2019), but also on the national and regional scales. While cost and total generation capacity are higher on smaller scales, they are likely not so high as to be economically infeasible, and these higher costs allow system operators to avoid transmission capacity expansion. Our results show how system cost of fully renewable electricity systems depend strongly on the balancing scale, but not as much on the supply scale, and that transmission needs can be traded off against generation capacity requirements. Thus, we show that very different system designs are possible, from the very small and regional to the very large and continental. It is important that policymakers and societies decide which type of system they find most attractive, in the knowledge that only one or the other can be built and that countries and citizens must accept either generation or transmission infrastructure for a transition to a fully renewable future in Europe to be feasible.

3.7 Experimental procedures

We model a possible future European electricity system as a set of network nodes and power flows between the nodes, with each node representing a regional administrative unit in Europe. We consider the deployment of renewable electricity supply and storage technologies at each node, and the deployment of transmission links between nodes, but disregard subordinate network nodes and power flows on the distribution system. With the exception of hydro run-of-river, hydro reservoir, and pumped storage hydro plants, we do not consider current legacy generation capacities or the current topology of the transmission system. Thus our model represents almost entirely a greenfield system. We use this approach in order to understand the effect of system scale and size irrespective of the influence of legacy generation.

Using the Calliope model framework (Pfenninger & Pickering, 2018), we build a linear programming model that simultaneously optimises electricity system design and operation for a single weather year, 2016, with a temporal resolution of four hours. We choose a single year to reduce problem size, but we test this choice by also modelling the weather years 2007–2016 in a sensitivity analysis (see below). The objective function of the model is to find the design with the lowest total system cost. An electricity system design is defined by a set of supply capacities at each node, storage capacities at each node, and transmission capacities between all nodes. All system designs fulfilling Kirchhoff's law, the technical constraints of all possible technology components, and political constraints (see below) are possible. We assume that electricity generation from photovoltaics, on- and offshore wind, and hydropower plants can be curtailed, i.e. the model can decide to lower actual generation at a certain point in time from the maximum generation given by the capacity factor time series described below.

3.7.1 Geographic scope and transmission grid

The study area comprises all countries represented by member organisations in the ENTSO-E: the EU-28, Norway, Switzerland, and Western Balkan countries. We exclude Iceland which is electricity autarkic, Cyprus, which is not directly connected to the rest of the study area, and Malta, for which insufficient data are available. We divide the study area into 497 regional administrative units (Tröndle, Pfenninger, & Lilliestam, 2019b), each of which is considered to be a transmission network node. We model the transmission grid as direct net transfer capacities between network nodes, i.e. we consider net power flows on the shortest distances between nodes only, and assume the distribution network within each node is able to handle distribution load. We allow transmission capacities between regional administrative units sharing a land border. We use currently existing sea connections and those that are currently under construction to connect regions that do not share a land border (ENTSO-E, 2019a). We furthermore connect the islands Hiiu and Saare to the Estonian mainland, resulting in a fully connected electricity network graph as visible in Figure B5.

3.7.2 System scale

We use two types of geographic scale as the basis for our system layouts. First, the scale of the electricity supply, and second, the scale of balancing of supply. Electricity supply on the continental, national, or regional scale requires that the entire continental, national, or regional electricity demand is satisfied annually with local electricity generation from wind, sun, biomass, and water. Within a year, electricity can be traded freely, as long as net annual imports reach 0.

We model the balancing scale by prohibiting electricity transmission between units on that scale. For national and regional scales this means that no electricity can flow between countries or regions. For the continental scale, this is given inherently by the scope of our study area.

3.7.3 Electrical load

We determine electrical load profiles for each regional administrative unit following the method described in Tröndle, Pfenninger, & Lilliestam (2019b). First, we derive the location and annual demand of industrial facilities with highest electricity demand in Europe from emission data of the European Emission Trading Scheme (European Environment Agency, 2018). We assume industrial load to be nearly constant and thus derive flat industry profiles for each regional administrative unit.

Second, we use measured national load profiles of 2016 (Muehlenpfordt, 2019) (for Albania no 2016 data is available and thus we use 2017 data) and subtract industrial demand to retrieve national profiles of residential and commercial load. We then assume residential and commercial load to be spatially distributed proportional to population counts. Using the Global Human Settlement Population Grid with a resolution of 250 m (JRC & CIESIN, 2015) we allocate residential and commercial load to regional administrative units.

Finally, we sum the two industrial and residential time series in each administrative unit to retrieve electricity load profiles at each network node.

3.7.4 Photovoltaics

Photovoltaics (PV) can be built at each network node. For each administrative unit, we first determine the maximum amount of capacity that can be deployed. Then, we determine the capacity factor time series which maps from installed capacity to electricity generation at each point in time.

Our model differentiates between PV deployed on open fields and on roof tops and uses geospatial data with a 10 arcsecond resolution. We allow open field PV to be built on areas of bare land (European Space Agency, 2010) or open vegetation (European Space Agency, 2010) that are not environmentally protected (UNEP-WCMC & IUCN, 2018), not inhabited (i.e. $< 1\%$ of the grid cell are buildings or urban greens according to Ferri et al. (2017)), and whose average slope (Danielson & Gesch, 2011; Reuter et al., 2007) is 10° at maximum (Al Garni & Awasthi, 2018). We assume a capacity density of 80 W/m^2 to derive the maximum amount of installable open field PV capacity for all regional administrative units.

To determine the maximum installable capacity of roof mounted PV, we consider inhabited areas only (i.e. $\geq 1\%$ of the grid cell are buildings or urban green areas according to Ferri et al. (2017)). Within those grid cells, we use building footprints from Ferri et al. (2017) as a proxy for the amount of available roof tops. Using the high-resolution Sonnendach.ch data set for Switzerland (Swiss Federal Office of Energy, 2018), we find that within Switzerland, the ratio between building footprints from Ferri et al. (2017) and rooftops available for PV deployment is 0.56. Due to the lack of comparable data for other countries, we apply this ratio for all of Europe to derive the maximum amount of roof space available for PV. We further differentiate between roof space on flat roofs and on tilted roofs based on the ratio from Swiss Federal Office of Energy (2018) and assume capacity densities of 160 W/m^2 for tilted roofs and 80 W/m^2 for flat roofs.

We derive capacity factor time series for roof mounted and open-field PV on a regular grid with 50 km edge length, resulting in around 2700 time series covering the study area. We assume a performance ratio of 90% and simulate the time series using Renewables.ninja (Pfenninger & Staffell, 2016; Staffell & Pfenninger, 2016). For roof mounted PV, because tilt and orientation of tilted roofs have a significant impact on capacity factors, we model 16 different deployment situations covering roofs facing east, south, west, and north, with tilts between 18° and 43°. We calculate a weighted average from the resulting 16 time series based on the distribution of roofs from Swiss Federal Office of Energy (2018) to derive a single time series for roof mounted PV for each 50 km grid cell. For open field PV we optimise the tilt based on location (Jacobson & Jadhav, 2018), so each 50 km grid cell has a single time series. By computing the weighted spatial average across grid cells whose centroid lies within a given administrative unit, we finally compute a single open field PV and a single roof mounted PV time series for each administrative unit.

3.7.5 Wind on- and offshore

Onshore and offshore wind capacities can be deployed at each network node, and we apply a method similar to the one for photovoltaics to derive their maximum amount of installable capacities and their capacity factor time series.

We use geospatial data with 10 arcsecond resolution to derive the maximum amount of installable wind power capacities. We allow onshore wind farms to be built on areas with farmland, forests, open vegetation, and bare land (European Space Agency, 2010) that are not environmentally protected (UNEP-WCMC & IUCN, 2018), not inhabited (i.e. < 1% of the grid cell are buildings or urban greens according to Ferri et al. (2017)), and whose average slope (Danielson & Gesch, 2011; Reuter et al., 2007) is 20° at maximum (McKenna et al., 2015). We allow offshore wind farms to be built in offshore areas within Exclusive Economic Zones (Claus et al., 2018) with water depths (Amante & Eakins, 2009) not below 50 m and which are not environmentally protected (UNEP-WCMC & IUCN, 2018). We assume capacity densities of 8 W/m^2 and 15 W/m^2 (European Environment Agency, 2009) for onshore and offshore wind. Where land is available for onshore wind farms and open field PV, either technology or a mix of both technologies can be used. We allocate the installable offshore capacities to those administrative units which share a coast with the Exclusive Economic Zone, and where there is more than one region, we allocate the capacities proportional to the length of the shared coast. We do not explicitly model the transmission network expansion needed to connect offshore farms.

We derive capacity factor time series for on- and offshore wind on the same 50 km^2 grid as we do for PV, resulting in around 2700 onshore grid cells and around 2800 offshore grid cells. We again use Renewables.ninja (Pfenninger & Staffell, 2016; Staffell & Pfenninger, 2016) to simulate wind generation at each grid cell, assume capacity factors to be constant within the cell, and generate a spatially weighted average to generate a capacity factor time series for each regional administrative unit.

3.7.6 Hydro run-of-river and reservoirs

We assume hydro run-of-river and hydro reservoir potentials to be largely tapped today (Lacal Arantegui et al., 2014) with almost no expansion potential. Thus, for hydro generation capacities we deviate from the greenfield approach and fix today's capacities.

We derive the location and installed power and storage capacities of hydro stations in Europe today from the JRC Hydro Power Database (Felice & Kavvadias, 2019). Where no storage capacity of hydro reservoirs is available, we use the median national ratio of power to storage capacity, and if that is not available, we use the median Europe-wide ratio of power to storage capacity.

To create power generation time series for each station, we use a two-stage approach. First, we derive water inflow time series for each station using an approach based on ERA5 runoff data (Dee et al., 2011) and hydrological basins (Lehner & Grill, 2013) described and validated for China in (Liu et al., 2019). We use Atlite (Andresen et al., 2015) to first determine all basins upstream of the hydropower station to be able to sum all upstream runoff while assuming a water flow speed of 1 m/s.

Second, we apply bias correction factors based on annual generation necessary for this method to represent the actual magnitude of the inflow and thus accurately model power generation. As we do not have data per station, we use national generation data from IRENA (IRENA, 2018). For hydro run-of-river plants we assume constant annual capacity factors within each country, which allows us to estimate the annual generation per plant. We use this estimation to derive electricity generation time series for each plant by scaling and capping the water inflow time series such that they sum to the annual generation without ever exceeding power capacities of the stations. For hydro reservoirs, we additionally assume they never need to spill water, i.e. their storage capacity is sufficient to use all inflowing water. We then scale the water inflow time series in such a way that they sum to the annual generation of the stations.

Using location data of each plant, we sum up time series as well as power and storage capacities per regional administrative unit. Our total resulting capacities are 36 GW for run-of-river and 103 GW / 97 TWh for reservoirs.

3.7.7 Bioenergy

We use estimations of biomass potentials for the year 2020 and reference assumptions taken from Ruiz Castello et al. (2015), but we assume no dedicated farming for energy crops and thus consider residuals and wastes only. The data is given as national aggregates, and we use national shares of farmland (European Space Agency, 2010), national shares of forests (European Space Agency, 2010), and national shares of population (JRC & CIESIN, 2015) as proxies to derive proportionally allocated potentials per regional administrative unit. Table B4 lists all feedstocks we consider together with the allocation proxy we use.

We assume an efficiency of 45% for the combustion of all biomass.

3.7.8 Pumped storage hydro

Similar to hydro run-of-river and hydro reservoir capacities, we assume pumped storage hydro capacities in Europe to be largely tapped (Lacal Arantegui et al., 2014) and do not allow for capacity expansion. Thus, we deploy today's pumped hydropower and storage capacities. We assume a round-trip electricity efficiency of 78% (Schmidt et al., 2019).

To determine location, power and storage capacity of each pumped hydro station in Europe today, we also use the JRC Hydro Power Database (Felice & Kavvadias, 2019). Where storage capacities are missing, we employ the same method as for hydro reservoirs: we assume national median ratios of power to storage capacity for all stations with missing storage capacity; and where this is not available, we assume Europe-wide median ratios of power to storage capacity. The storage capacities from the JRC Hydro Power Database sum up to more than 10 TWh, which is an order of magnitude above the 1.3 TWh reported by Geth et al. (2015). To ensure that we do not overestimate the pumped storage potential we therefore scale storage capacities to match national data reported by Geth et al. (2015). Using location data of each station, we then sum all power and storage capacities within regional administrative units to form a single pumped hydro capacity per unit.

3.7.9 Short-term and long-term storage

We assume that short-term and long-term storage capacities can be deployed in all regional administrative units. We model short-term storage as Lithium-ion batteries and assume long-term storage is provided by hydrogen, as they are likely to become the dominant technology in their respective applications (Schmidt et al., 2019). The models are based on two technical parameters: the ratio between power and storage capacity, and the round-trip efficiency. Short-term storage is constrained to a maximum capacity of 4 h of full power, while long-term storage has a minimum of 4 h capacity at full power. We assume 86% of round-trip efficiency for short-term and 40% for long-term storage.

Additionally, we assume that power and storage capacities can be expanded independently, constrained only by the above mentioned minimum and maximum storage capacities.

3.7.10 Insufficient potentials

In some regions, local technical potential for renewable electricity is not high enough to satisfy local electricity demand (Tröndle, Pfenninger, & Lilliestam, 2019b). This is problematic in system layouts in which regions strive for self-sufficiency. To provide sufficient electricity supply in these regions, we connect them with a neighbouring or the encompassing region: Vienna with Lower Austria, Brussels with Flanders, Berlin with Brandenburg, Oslo with Akershus, and Basel-City with Basel-Country. For the regional-scale system, but also for continental- and national-scale systems with regional self-sufficiency, we therefore require self-sufficiency of each combined region in these five corner cases.

3.7.11 Technology cost

We assess the long term (quasi steady state) cost of electricity supply. We aim neither to determine the cost of a transition to a future system nor to consider disruptive developments on the global market for supply and storage technologies. Thus, our cost are based on expected learning rates and the assumption that renewable generation and electricity storage technologies will have been deployed at cumulative capacities consistent with our study. Cost estimates for the year 2050 are primarily from (JRC, 2014) for supply and transmission technologies, from (Schmidt et al., 2019) for storage technologies, and from (Ruiz Castello et al., 2015) for fuel cost of bioenergy. See Table B5 for an overview of all cost assumptions.

Technology cost is modelled as the sum of overnight capacity cost, annual maintenance cost based on installed capacity, and variable cost per unit of generated electricity. For solar and wind we assume a small variable cost of 0.1 €ct / kWh to encourage curtailment whenever generation potential is higher than demand and storage capacities. We subtract these variable cost from the fixed operation and maintenance cost based on average capacity factors, so that they do not increase the overall cost of solar or wind technologies. For all hydropower technologies, we consider annual maintenance and variable cost only, since we assume that maximum capacities are already built today, so overnight cost of hydropower has no impact on our results.

Technology lifetime and cost of capital are used to derive annuities for each technology. We assume cost of capital to be 7.3% for all technologies and all locations based on historic average cost of capital for OECD countries (Steffen, 2019). Some recent literature suggests cost of capital are likely specific to technology (Egli et al., 2018; Steffen, 2019) and location (Ondraczek et al., 2015; Steffen, 2019), but we consider the data available so far too sparse to provide a solid basis on which to model this.

3.7.12 Sensitivity to meteorological conditions

While we use only a single year of meteorological conditions, 2016, in the analysis of system layouts described in the article, we use ten years, 2007–2016, to analyse the sensitivity of our results to meteorological conditions impacting generation from wind and solar power. We keep all other factors, including time series for electricity demand and hydropower, fixed. We re-run the model with the full ten years of data considered for the optimisation. In this way, we are not assessing the variability between meteorological years, but we are assessing how much the result changes when considering a wider range of meteorological conditions.

We are interested in the sensitivity of one of the main outputs of our study: relative total system cost of the national-scale system using the continental-scale system as a baseline. Because computational requirements to solve a model with regional spatial resolution and temporal resolution of 4h for ten years are too high, we perform this sensitivity analysis using a model with national spatial resolution while keeping temporal resolution the same. Comparing the results between national and regional resolution for the case with only one year of meteorological conditions, we find a difference of 8% for the relative cost of the national-scale system.

The additional cost of the national-scale system compared to the continental-scale system, however, is unaffected by the longer time duration: the difference to the case with only one year is negligible (< 1‰). This is not to say that cost and design of the electricity system is not sensitive to meteorological conditions. In fact, we find that total system cost is generally slightly higher, and more wind and bioenergy capacities are deployed in exchange of solar capacities. However, large-scale and small-scale systems are impacted similarly and so the difference between both is unaffected by the longer time duration of considered meteorological conditions. These results justify the use of only a single meteorological year.

3.7.13 Sensitivity to technology cost

We furthermore assess the uncertainty of our results stemming from uncertainty of technology cost. While we do know current cost and we do know it is likely to fall with deployment due to learning effects, we do not know exact future cost with certainty. This uncertainty stems primarily from two sources. We do not know the deployment rates of renewable technologies and we do not know how much cost will fall with deployment. In our analysis, we are assuming that renewable technologies are heavily deployed, so we focus on the second uncertainty: the relationship between deployment and cost reductions. Since we perform cost minimisation, the absolute total system cost of any assessed electricity system layout can be sensitive to the cost of its constituent technologies, as shown for example in Moret et al. (2017).

We assess the sensitivity of differences in system cost and technology deployment between large and small-scale system layouts. We consider as uncertain parameters the cost of ten different technologies, the weighted cost of capital, and the availability of biomass for combustion. Following a maximum entropy approach, we model their uncertainty with uniform distributions over ranges taken from the literature (see Table B1). We perform a global sensitivity analysis of system cost and several other model outputs in this twelve dimensional space. This allows us to derive the distribution of each model output and it allows us to derive total and first-order Sobol' indices. The Sobol' indices determine the share of the variation of each output that is explained by the variation of each input. Building on this, we use the indices to rank input parameters based on their importance for the uncertainty of each output.

To derive the output distribution and Sobol' indices, we need to let parametric uncertainty propagate into and through the model. In a classical Monte Carlo simulation, the input distributions are sampled many times to derive samples of the output. Because of the high computational requirements, in particular the time our model takes to run, this approach would be prohibitive for our study. Thus, we employ a method described in refs. Sudret (2008) and Le Gratiet et al. (2017) to perform a polynomial chaos expansion of our original model to derive a surrogate model. We use the MATLAB package UQLab (Marelli & Sudret, 2014). From this surrogate model, Sobol' indices can be determined analytically and the distribution of the outputs can be derived using Monte Carlo sampling. We derive the surrogate model by sampling 150 times from the input parameters using maximin Euclidean-distance-optimised Latin Hypercube Sampling, and by running continental-, national-, and regional-scale models each once for each input parameter vector. Due to the high computational requirements of running national- and continental-scale models, we perform these runs on a spatial resolution with low fidelity in which each country represents one transmission grid node. To remove the biases these low fidelity model runs inhibit, we perform 10 additional runs on the original, high-fidelity resolution and use a multi-fidelity approach (Palar et al., 2016) to retrieve a single surrogate model for continental and national scales. The estimated empirical error of the surrogate model is below 5% and thus we deem the surrogate sufficiently accurate (Le Gratiet et al., 2017) to derive total- and first-order Sobol' indices.

4 Supply-side options to reduce land requirements of fully renewable electricity in Europe

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Abstract

Renewable electricity can fully decarbonise the European electricity supply, but large land requirements may cause land-use conflicts. Using a dynamic model that captures renewable fluctuations, I explore the relationship between land requirements and cost of different supply-side options. Cost-minimal fully renewable electricity requires some 97,000 km^2 (2% of total) land for solar and wind power installations, roughly the size of Portugal, and includes large shares of onshore wind. Replacing onshore wind with offshore wind, utility-scale PV, or rooftop PV reduces land requirements drastically, with cost penalties that must not be large. Moving wind power offshore is most cost-effective and reduces land requirements by 50% for a cost penalty of only 5%. Wind power can alternatively be replaced by photovoltaics, leading to a cost penalty of 10% for the same effect. My research shows that fully renewable electricity supply can be designed with very different physical appearances and impacts on landscapes and the population, but at similar cost.

4.1 Introduction

Europe has the potential to generate all its electricity from renewable sources (Jacobson et al., 2017; Ruiz et al., 2019; Tröndle, Pfenninger, & Lilliestam, 2019b). The potential provides a possibility to decarbonise the European electricity system, which is a necessary step to reach the European Commission's goal of becoming a climate-neutral economy by 2050 (European Commission, 2018). Compared to the predominant forms of electricity supply based on fossil and nuclear fuels, land requirements of renewable electricity are high (MacKay, 2008; Smil, 2015; Stevens et al., 2017; van Zalk & Behrens, 2018), however. A transition to renewable electricity will therefore increase the total land requirements of electricity supply and it may even do so by orders of magnitude.

While renewable electricity is an indispensable option to mitigate global climate change, its high land requirements have the potential to cause conflicts locally where it is built. This is for three reasons. First, it may compete with other uses of land. Of the main two current technologies of renewable electricity, photovoltaics and wind turbines, only the latter allows for limited dual use of land: for technical reasons, spacing between turbines is large and, as a result, that land can be used for agriculture (Smil, 2015). Second, renewable generation infrastructure has the potential to economically devaluate land on which it is built, and also neighbouring land. There is conflicting evidence whether wind power in sight of properties impacts property values, and while the majority of studies does not find statistically significant impacts, some others find losses in property values of up to 15% (Brinkley & Leach, 2019). Third, wind (Molnarova et al., 2012) and solar power (Sánchez-Pantoja et al., 2018) are sometimes perceived as negatively impacting the landscape, depending on place attachment and the aesthetics of the previously undisturbed landscape (Devine-Wright & Howes, 2010; de Vries et al., 2012; Molnarova et al., 2012), and location and density of structures (Molnarova et al., 2012).

While the acceptance of the energy transition is generally high and the majority of the population does not feel disturbed by wind and solar installations (Knebel et al., 2016; Setton, 2019), local opposition has hindered and delayed local renewable electricity projects in the past (Späth, 2018; Stokes, 2016). Opposition may continue in the future, considering the large expansion of impacted land area moving towards fully decarbonised electricity supply (Setton, 2019). This led some authors to the conclusion that fully renewable electricity – while being theoretically possible – will not be feasible in Europe (MacKay, 2008; Smil, 2015).

Strategies to mitigate negative impacts associated with the land requirements of renewable electricity include location and placement of generation infrastructure (Molnarova et al., 2012) and technology choice to reduce land requirements (Palmer-Wilson et al., 2019). If proven effective, these strategies can not only reduce negative side-effects, but also increase the feasibility of electricity systems with large shares of renewable electricity by reducing opposition.

In this article, I explore the relationship between land requirements and cost of fully renewable electricity systems in Europe with different supply sides. Renewable supply technologies have vastly different land requirements, with two orders of magnitude between the land requirements of bioenergy, the technology with the largest land requirements, and solar electricity, which has the lowest (Smil, 2015; van Zalk & Behrens, 2018). Previous research shows that fully renewable electricity supply in Europe is possible in many different ways, with very different shares of supply technologies, and that cost between different designs must not vary much (Neumann & Brown, 2019; Schlachtberger et al., 2017; Tröndle, Lilliestam, et al., 2020). However, while several studies have assessed cost (T. W. Brown et al., 2018; Bussar et al., 2014; Child et al., 2019; Connolly et al., 2016; Jacobson et al., 2017; Pleßmann & Blechinger, 2017) and land requirements (Capellán-Pérez et al., 2017; Fthenakis & Kim, 2009; Jacobson et al., 2017; Tröndle, Pfenninger, & Lilliestam, 2019b) of supply technologies and entire electricity systems, only one study has assessed the relationship between the two on the system level (Palmer-Wilson et al., 2019). The system perspective is central to renewable electricity systems as it takes into account not only the supply side but also technologies to handle fluctuations of the supply side. In their case study of Alberta, Canada, the authors find higher total system cost for lower land requirements even though they allow for large amounts of electricity from non-renewable sources. No study has assessed the relationship between land requirements and cost on the system level using only renewable resources in Europe. I address the relationship in this study by determining cost-effective ways to reduce land requirements of fully renewable electricity systems in Europe through supply technology choice.

To find cost-effective ways to reduce land requirements, I do the following: I use a nationally resolved, dynamic model of the European electricity system to determine cost and land requirements of fully renewable supply. I find that, while there is a trade-off between cost and land requirements, systems with vastly different requirements for land can be build with small cost penalties.

4.2 Data and methods

To be able to identify cost-effective ways to reduce land requirements by supply technology choice, I generate total system cost and total land requirement data for fully renewable electricity supply in Europe with different shares of supply technologies using a model-based approach. I generate the data in two steps. First, I generate cost-minimised system designs for 286 different shares of supply technologies. Second, I determine total system cost and land requirements for each system design. Using the Monte Carlo method respecting uncertainty of technology parameters, I create 100,000 samples for each system design. In total, I end up with ~29 million observations of pairs of cost and land requirements.

The following subsections explain all data generation and analysis steps in more detail.

4.2.1 Capacity shares of supply technologies

To understand how supply technology choice can mitigate land requirements of renewable electricity in Europe, I enforce different capacity shares of technologies in the system designs that I am analysing. The geographic scope of this study includes most countries with member organisations in the entso-e: EU-27, the United Kingdom, Switzerland, Norway, and Western Balkan countries. I focus on four dominant wind and solar supply technologies: on- and offshore wind, utility-scale, ground-mounted photovoltaics (PV) and roof-mounted PV. I analyse all 286 possible combinations based on ten different shares per technology, from 0% through 10% and 20% up to 100% (see Figure 4.1). The shares are applied to the European level, but also to the national level, meaning that each country in Europe has to meet shares individually. Furthermore, I assume each country to be net self-sufficient, generating enough electricity annually to fulfil its domestic electricity demand but able to trade with other countries to balance renewable fluctuations.

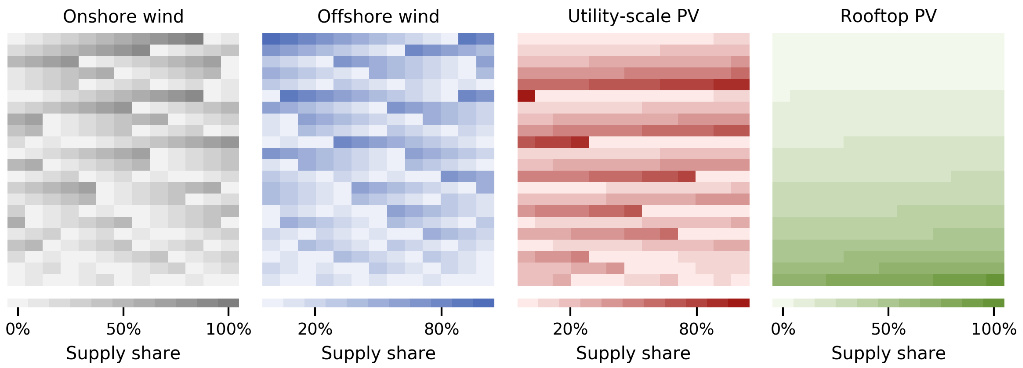

Figure 4.1: Capacity shares of all 286 system designs for four supply technologies. Pixels in each panel represent one system design. System designs are in no particular order. Shares of the same pixel in all panels always add to 100%.

Other than these four supply technologies, the system designs furthermore contain hydro electricity with and without reservoirs and bioenergy, all of which can generate renewable electricity to a limited extent as well. While I do not restrict their capacity shares, they are both restricted by their generation potential: hydro electricity is limited to the amount that can be generated using current capacities, and bioenergy is limited to the amount of bioenergy that can be generated from residuals (see System design model). Both contribute to electricity supply, but only to minor extents. Hydro electricity with reservoirs and bioenergy are used to balance renewable fluctuations as well.

Each country in Europe can potentially generate enough electricity from rooftop PV, utility-scale PV, and onshore wind to cover national demand together with limited generation from hydroelectricity and bioenergy (see “System design model” and “Discussion”). Thus, system designs with 100% rooftop PV, 100% utility-scale PV, or 100% onshore wind are possible. The situation is different for offshore wind: while the generation potential for all Europe is large enough to cover European demand, only countries with shores can build offshore wind farms. In countries without shore I replace offshore wind with onshore wind; i.e. when all countries with shores have to enforce a 40% capacity share of offshore wind, and a 20% capacity share of onshore wind, all countries without shores have to have a 60% capacity share of onshore wind. Countries without shores, or with insufficient offshore potentials are: Austria, Bosnia and Herzegovina, Switzerland, Czech Republic, Hungary, Luxembourg, Macedonia, Serbia, Slovakia, and Slovenia.

Based on the enforced supply capacity shares, the system design model determines absolute installed capacities in each country for all supply technologies, but also for all storage and international transmission capacities.

4.2.2 System design model

The system design model determines cost-minimal system designs for Europe. The model is a network flow model with the electricity transmission grid at its core. Each country in Europe is modelled as a node on the network and all nodes are connected through the transmission grid. The model has a 4h resolution and simulates one full weather year to cover renewable fluctuations. It is a linear optimisation model that optimises system design and operation simultaneously. The model is implemented using the Calliope model framework (Pfenninger & Pickering, 2018) and has been used in a former publication. It is described in full detail in (Tröndle, Lilliestam, et al., 2020).

On the supply side, the model contains four main renewable technologies to generate electricity: on- and offshore wind, and utility-scale and rooftop PV. In addition, hydroelectricity with and without reservoirs, and bioenergy can generate electricity. Capacities are limited by their technical potentials, which I derive from (Tröndle, Pfenninger, & Lilliestam, 2019b) for wind and solar power, and from (Tröndle, Lilliestam, et al., 2020) for hydroelectricity. For hydroelectricity, I assume no further expansion from today is possible, and thus its technical potential equates to today's capacity. For wind and solar power, I allow any capacity up to their technical potential. Generation profiles are based on weather data (Dee et al., 2011; Pfenninger & Staffell, 2016; Staffell & Pfenninger, 2016) and taken from the same sources as the potentials. Based on the enforced supply capacity shares, the system design model determines cost-minimal capacities of supply technologies.

To balance fluctuating hydro, solar, and wind generation, system designs contain battery storage, hydrogen storage, pumped storage hydroelectricity, and bioenergy. All storage technologies are modelled as single storage tanks with efficiencies, i.e. there is no flow of energy in any other form than electricity. Battery storage can discharge for a maximum of four hours at full power, while hydrogen storage can discharge for at least four hours. Bioenergy is limited by the amount of fuels that can be produced from residuals in each country per year (Ruiz Castello et al., 2015), i.e. I do not assume dedicated farming for energy crops. The limited fuel supply and high fuel cost make bioenergy a technology mainly used for balancing, rather than for supplying electricity. Bioenergy and storage capacities other than pumped hydro are not restricted in any way. I assume pumped storage hydroelectricity can not be expanded significantly and it is thus limited to today's capacities (Tröndle, Lilliestam, et al., 2020). The system design model determines cost-minimal capacities of all balancing technologies.

All supply, balancing, and international transmission capacities have costs: overnight installation costs, annual maintenance costs, and variable costs (see Table 4.1). The technology costs are important determinants of the magnitude of capacities chosen by the system design model. Their values are future projections and assume all technologies are deployed at large scale. Together with the technology lifetime, I determine annuities from these cost components. I uniformly assume cost of capital to be 7.3%, which has been the historic average (Steffen, 2019).

Table 4.1: Technology cost assumptions. ^AC transmission overnight cost is given in €/kW/1000km

Technology	Overnight cost (€/kW)	Overnight cost (€/kWh)	Annual cost (€/kW/yr)	Variable cost (€ct/kWh)	Lifetime (yr)	Source
Utility-scale PV	520	0	8	0	25	Ref. JRC (2014) Table 7
Rooftop PV	880	0	16	0	25	Ref. JRC (2014) Table 9
Onshore wind	1100	0	16	0	25	Ref. JRC (2014) Table 4

Technology	Overnight cost (€/kW)	Overnight cost (€/kWh)	Annual cost (€/kW/yr)	Variable cost (€ct/kWh)	Lifetime (yr)	Source
Offshore wind	2280	0	49	0	30	Ref. JRC (2014) Table 5
Biofuel	2300	0	94	6	20	Ref. JRC (2014) Table 48, ref. Ruiz Castello et al. (2015)
Hydropower run of river	0	0	169	0	60	Ref. JRC (2014) Table 14
Hydropower with reservoir	0	0	101	0	60	Ref. JRC (2014) Table 12
Pumped hydro storage	0	0	7	0	55	Ref. Schmidt et al. (2019)
Short term storage	86	101	1	0	10	Ref. Schmidt et al. (2019)
Long term storage	1612	9	14	0	15	Ref. Schmidt et al. (2019)
AC transmission^	900	0	0	0	60	Ref. JRC (2014) Table 39

While future cost is uncertain, I am using expected values in the deterministic system design model. To cover the aspect that future cost is not know exactly, I handle cost uncertainties in the generation steps that follow the system design phase.

4.2.3 Cost uncertainty

Cost of almost all components of future renewable electricity systems can be expected to fall compared to today. Cost falls with deployment as production processes get improved, product understanding increases with the use, and financing can be provided with lower overheads. Exactly how much cost will fall with deployment is not known, however. To cover this uncertainty, I am using minimum and maximum estimates of cost (JRC, 2014) of the four supply technologies analysed in this study. Because I do not have any other information about how likely any cost developments are, I am following the principle of maximum entropy and I am assuming a uniform distribution between minimum and maximum estimates in the following, see Table 4.2.

I only consider uncertainty in cost of on- and off-shore wind, and utility-scale and rooftop PV, first because these are the technologies whose cost-effectiveness I am assessing in this study. Second, because changes in their cost can have no impact on supply capacity shares which I enforce. Changes in cost of other technologies could lead to different designs, for example if hydrogen storage cost is much higher than the expected value, hydrogen may be replaced with bioenergy. For this reason, I use expected values only (see Table 4.1) for all other components other than the four wind and solar supply technologies.

Table 4.2: Uncertain input parameters. Parameters with uniform distribution are represented by their min and max values. Parameters with normal distribution are represented by their mean and standard deviation.

Name	Description	Distribution	Min/ Mean	Max/ Std	Source
Cost onshore wind	Cost scaling factor of on-shore wind.	uniform	0.727	1.545	Ref. JRC (2014) (Table 4)
Cost offshore wind	Cost scaling factor of off-shore wind.	uniform	0.785	1.434	Ref. JRC (2014) (Table 5)
Cost rooftop PV	Cost scaling factor for rooftop PV.	uniform	0.864	1.136	Ref. JRC (2014) (Table 9)
Cost utility-scale PV	Cost scaling factor for utility-scale PV.	uniform	0.538	1.115	Ref. JRC (2014) (Table 7)

Name	Description	Distribution	Min/ Mean	Max/ Std	Source
Land requirements wind	Onshore wind capacity density [W/m^2].	normal	8.820	1.980	Ref. van Zalk & Behrens (2018)
Efficiency utility-scale PV	Module efficiency of utility-scale PV.	uniform	0.175	0.220	Ref. Wirth (2020)
Land requirements utility-scale PV	Share of land that is covered by PV modules.	uniform	0.400	0.500	Refs. Turney & Fthenakis (2011) Wirth (2017) Smil (2015)

4.2.4 Land requirements

To determine land requirements of supply technologies, I assume capacities of technologies always to require the same amount of land and therefore apply a proportional constant to installed capacities: the inverse of capacity density, given in square meters per Watt. As the range of capacity density values given in the literature is large for onshore wind and utility-scale PV, I am using a stochastic approach here as well.

Land requirements of onshore wind in this study are those of the wind turbines together with the technically necessary spacing between turbines. While the spacing can be used for agriculture, it excludes other land uses and the spacing also does not reduce visual impacts. Thus, I include spacing in the land requirements of wind turbines in this study.

Theoretically, the capacity density of onshore wind can be high: based on technical specifications, it is up to 19 W/m^2 for the best turbines and ~10 W/m^2 on average (McKenna et al., 2015). However, in deployed wind farms, the capacity density is lower, with values between 2–10 W/m^2 (Miller & Keith, 2019; Nitsch et al., 2019; Smil, 2015; van Zalk & Behrens, 2018). This can have different reasons: the capacity density depends on the placement of turbines in the wind park and it depends on the technical specifications of the wind turbine. More importantly, because land is not the most important cost component of wind farms, farms are not necessarily build in a way to maximise capacity density. In this study, I am using a capacity density estimate taken from (van Zalk & Behrens, 2018) based on measurements in the US. Here, the authors found 8.8 W/m^2 on average with a standard deviation of ~2 W/m^2, see Table 4.2.

Uncertainty about land requirements of utility-scale PV is similarly high. Around 40%–50% of the area of solar farms is covered by modules (Smil, 2015; Turney & Fthenakis, 2011; Wirth, 2017), while the rest of the land is used for inverters, power lines, spacing, and roads. In addition, the technology used, orientation, and efficiency of the PV modules have great impact on land requirements as well as they determine the capacity installable on the area covered by modules. Theoretically derived capacity densities using today's module efficiencies are in the range of 80–100 W/m^2 (Wirth, 2017), but measurements from the US show much lower estimates of 20–30 W/m^2 only (Miller & Keith, 2019; Smil, 2015; van Zalk & Behrens, 2018). A recent study from Germany shows, however, that the capacity density of German utility-scale PV has increased drastically over time: in less than 20 years, it increased by factor 3 to ~70 W/m^2 in 2018 (ZSW & Bosch & Partner, 2019). The authors explain the trend not only by increasing module efficiencies, but also by more economic use of land. These findings show that theoretically derived capacity densities may actually be more accurate for future projections than historic measurements, and I am therefore using capacity densities derived from theory. I am assuming that land is covered to 40–50% by modules (Smil, 2015; Turney & Fthenakis, 2011; Wirth, 2017), and that module efficiency is between 17.5–22% (Wirth, 2020), see Table 4.2. Assuming a uniform distribution for both, this leads to an expected capacity density value of utility-scale PV of ~88 W/m^2.

The remaining two supply technologies, rooftop PV and offshore wind, have no land requirements whatsoever. Rooftop PV is built on existing structures, and offshore wind is not built on land. This makes them promising options for reducing total land requirements of renewable electricity systems.

Hydroelectricity, bioenergy, storage, and transmission will all require land which I am not analysing in detail in this study. The reasons why I ignore land requirements of each of the components are the following: First, I do not analyse land requirements of hydroelectricity in detail, because system designs in this study all contain the exact amount that is installed today. Thus, hydroelectricity's land requirements in all cases are the same, and equal to today's. Today's requirements are not small, however. They are dominated by the extent of water reservoirs (Smil, 2015), which span roughly 50,000 km^2 (1% of total land) in Europe (Halleraker et al., 2016). Not all of the reservoirs in Europe are used for electricity generation, and even less are used exclusively for it (Halleraker et al., 2016), so this total number can be seen as an upper bound of the land requirements of hydroelectricity.

Second, land requirements of bioenergy are very small as long as only residuals are used for fuel production. When dedicated energy crops are farmed, bioenergy has the lowest capacity density of all renewable technologies (van Zalk & Behrens, 2018). The by far largest contribution to its land requirements stems from fields for crop farming, however. Because I allow only residuals to be used for electricity generation, land requirements include the power plants only, which leads to a capacity density in the order of 10^4 W/m^2 (Smil, 2015) and thus 2–3 orders of magnitude larger than solar and wind power. This makes bioenergy's contribution to total system land requirements insignificant and I am therefore ignoring it in this study.

Third, land requirements of electricity storage depend on the amount of electricity that must be stored. Commercial suppliers offer 1 MW / 1 MWh battery storage systems in standardised container enclosings today (Aggreko, 2020), leading to a capacity density in the order of 10^5 W/m^2 and 10^5 Wh/m^2. Power-wise, a capacity density of this magnitude makes the land requirements of battery storage insignificant compared to the one of solar and wind power, even if spacing, roads and further infrastructure must be added. Energy-wise, capacity density cannot be compared to solar and wind power, and the total land requirements depend on the amount of electricity that must be stored in batteries. This is equally true for hydrogen storage. Here, the energy-wise capacity density depends on how hydrogen is stored. Hydrogen has a low energy density of 3 kWh/m^3 if stored uncompressed at normal conditions. It can be stored underground in salt caverns, or overground in steel tanks. Capacity density is lowest if hydrogen is stored in such overground tanks in uncompressed form. Together with a conservative height of the tanks of 2 meters, this equals 6,000 Wh/m^2. This conservative estimation is worse than the one for battery storage. Because much more electricity is anticipated to be stored as hydrogen rather than in batteries, total land requirements of hydrogen storage may be high, if it is not stored in compressed forms, in tanks taller than 2 meters, or underground, and if large amounts must be stored. The latter is not the case for the system designs I am considering in this study (see "Storage and flexible generation require small amounts of land" in results section), and thus I am ignoring land requirements of battery storage and hydrogen storage.

Lastly, the transmission grid has already today significant land requirements, which will likely increase in fully renewable systems. Currently, there are 480,000 km of AC transmission lines in the entso-e grid (ENTSO-E, 2019b). With an estimated 13.5 m buffer zone on each side (Stevens et al., 2017), this leads to 13,000 km^2 (0.3%) of land required. A former study found that fully renewable electricity requires roughly a doubling of the transmission capacity when countries are net self-sufficient (Tröndle, Lilliestam, et al., 2020), as they are in this study. Considering power per line remains the same as it is today, their scenario would require 25,000 km² (0.5%) of European land for transmission lines. Despite these numbers, I am not assessing the land requirements of transmission in this study. The spatial resolution of this study, the national level, is too high to determine necessary land for transmission.

4.2.5 Stochastic model

I use technology cost and technology land requirement parameters to derive total system cost and total land requirements of solar and wind power in all 286 system designs stemming from the system design phase. I do this in two steps. First, I sample 100,000 times from the input uncertainties using Saltelli's extension of the Sobol sequence (Herman & Usher, 2017) to derive a sufficiently large sample set of the seven dimensional input space. Second, for each sample and each system design I derive total land requirements of solar and wind power by applying the inverse of capacity density to the installed capacity in the system design. Similarly, I derive total system cost by scaling technology cost of solar and wind from the system design with the factors given from the input sample. This leads to ~29 million observations of pairs of cost and land requirements, which I am using to analyse cost effectiveness of different supply technologies.

4.3 Results

4.3.1 Renewable electricity supply with vastly different land requirements

Among all ~29 million observations, cost of electricity in all Europe is between 0.06 and 0.10 EUR per kWh consumed while land requirements of solar and wind power are between 0% and 3% of total European land (see Figure 4.2). These ranges include all possible cases of supply share combinations, including systems supplied, apart from hydroelectricity and bioenergy, exclusively from onshore wind, utility-scale PV, and rooftop PV, or with high shares of offshore wind. The ranges furthermore contain technology cost and technology land requirement parameters from the full range of their uncertainty. The observations show that European electricity systems with vastly different land requirements are possible at cost never exceeding twice the lowest cost.

When I reduce uncertainty distributions to their expected values (their means), I find that there is a trade-off between expected land requirements of renewable electricity and its expected cost. Among all 286 system designs with different supply shares, a system with only onshore wind and utility-scale PV has the lowest expected cost of around 0.07 EUR per kWh consumed and requires 2% of

Europe's total land (~97,000 km^2) – an area roughly the size of Portugal. Cost is minimal when both technologies contribute 50% to the total capacity of wind and solar technologies. While higher shares of utility-scale PV decrease land requirements, they also increase cost (see right flanks in Figure 4.3a,b). Higher shares of onshore wind increase both cost and land requirements. A system design with only onshore wind has the highest expected land requirements (see top corner of Figure 4.3b). Rooftop PV has the largest potential to decrease land requirements, as it requires no additional land, but it also increases cost the most (see left corners of Figure 4.3a,b).

Electricity system designs with offshore wind in addition to onshore wind and utility-scale PV have lower cost when they do not include rooftop PV (see Figure 4.3c). The potential of offshore wind to decrease land requirements is smaller than the one of rooftop PV, but only slightly (see Figure 4.3d). While offshore wind requires no additional land – similar to rooftop PV – it is not available in every country in Europe and is replaced by onshore wind in these places. Compared to onshore wind, the land requirements of all other three supply technologies – offshore wind, utility-scale PV, and rooftop PV – are lower and thus, system designs with large shares of any of these alternatives have smaller total land requirements, albeit at higher cost.

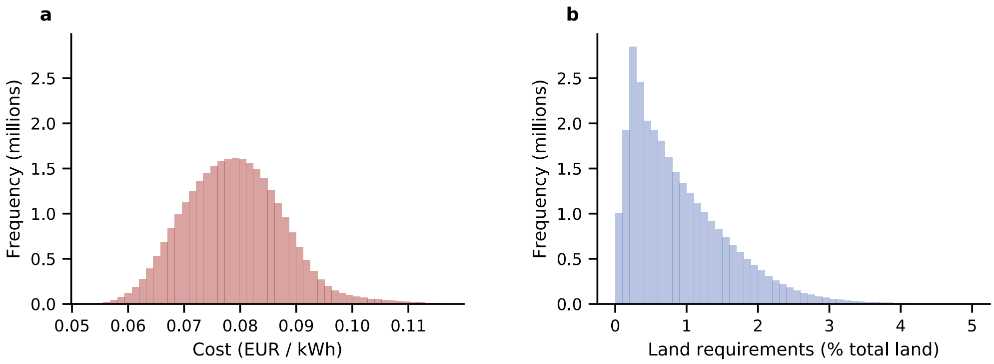

Figure 4.2: All ~29 million observations of cost and land requirements of fully renewable electricity systems with different shares of solar and wind supply technologies and considering uncertainty in technology cost and land requirements. a, System cost relative to electricity demand. **b,** Land requirements of solar and wind power, relative to total land in Europe.

4.3.2 Offshore wind reduces land requirements most cost-effectively

The rather large expected land requirements of the cost-minimal case can be reduced most cost-effectively by replacing onshore wind with offshore wind. In this way, total land requirements of renewable electricity can be reduced by 50% (to 1% of total land) for a cost penalty of 5% (see Figure 4.4a). This cost penalty corresponds to 0.22 EUR per m^2 and year and comes at a share of offshore wind of

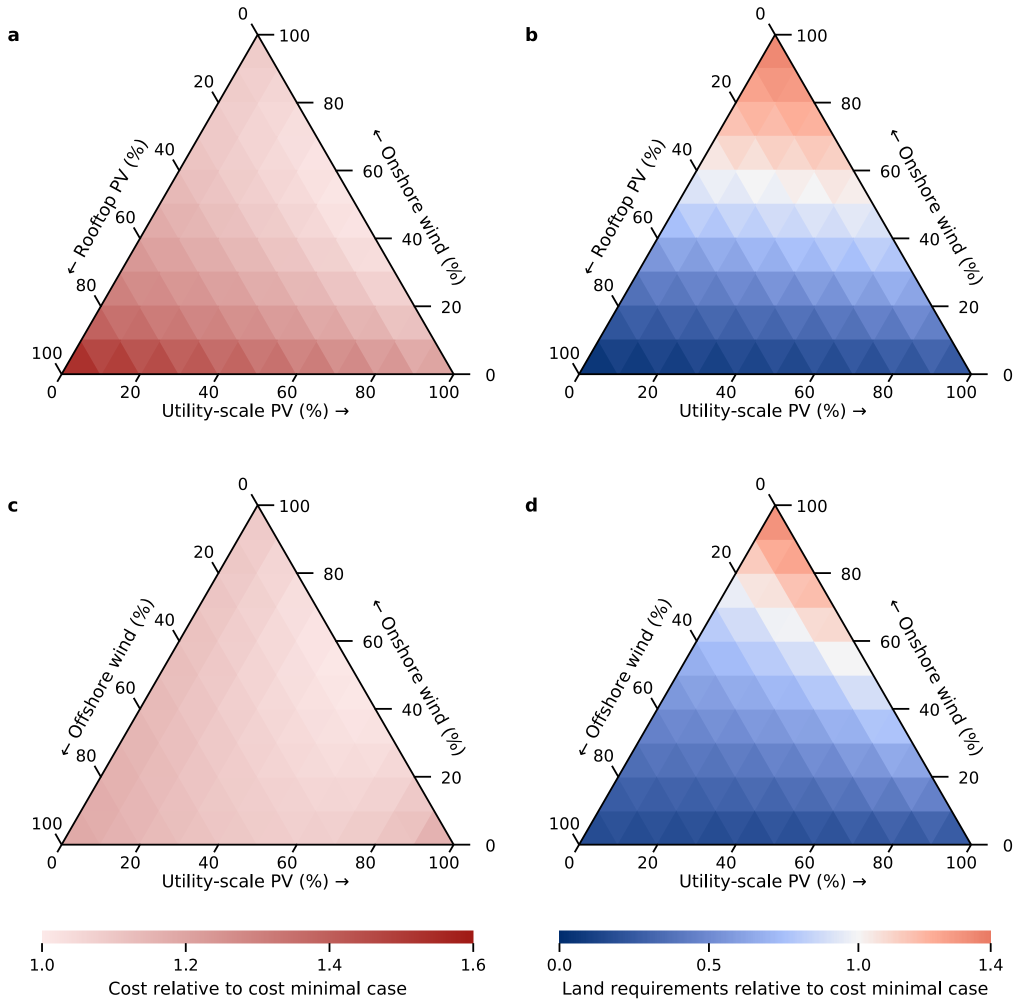

Figure 4.3: Expected cost and land requirements of fully renewable electricity systems with all possible shares of three different supply technologies. All cases include hydroelectricity of today's capacity and bioenergy from residuals next to three solar and wind technologies. Expected values are the means of uncertainty distributions. **a,b,** Total system cost (**a**) and land requirements (**b**) of cases with utility-scale PV, onshore wind and rooftop PV as supply side options. **c,d,** Total system cost (**c**) and land requirements (**d**) of cases with utility-scale PV, onshore wind, and offshore wind as supply side options.

~25%. Land requirements can be decreased further, in total by 85%, with higher shares of offshore wind. However, cost increase sharply for the last minor reductions in land, for which utility-scale PV must be phased out (see two left-most points in Figure 4.4a).

Reducing land requirements with utility-scale (see Figure 4.4b) and rooftop PV (see Figure 4.4c) has higher cost. To reach the same reduced land requirements of 50% below the cost-minimal case (1% of total land) higher shares of utility-scale PV lead to a cost penalty of ~10%, corresponding to 0.43 EUR per m^2 and year. Cost rises progressively however, and early decreases of land requirements have

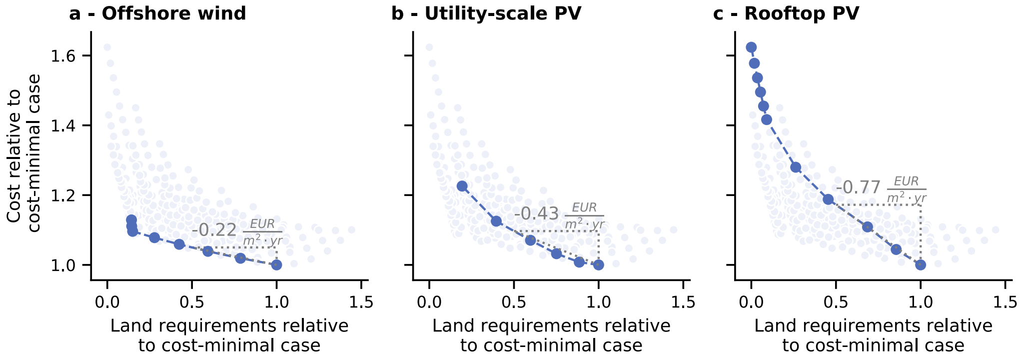

Figure 4.4: Cost-effective ways to reduce expected land requirements using supply technologies individually. All panels show expected cost and expected land requirements of all 286 system designs in light blue in the background. **a,b,c,** Dark blue cases show Pareto-optimal decreases of land requirements from cost-minimal case using offshore wind only (**a**), utility-scale PV only (**b**), and rooftop PV only (**c**).

very low cost. In total, 80% of the cost-minimal land requirements can be removed with a cost penalty of 23% using utility-scale PV only.

The highest expected cost comes with phasing-in rooftop PV. Here, reducing land requirements by one square meter requires 0.77 EUR per year when reducing cost-minimal requirements by 50% (to 1% of total land, see Figure 4.4c) – this is a cost penalty of 17%. Similar to utility-scale PV, the cost increases with higher rooftop shares and the largest increase can be explained by the technology that is phased-out: the first half of rooftop PV replaces onshore wind, while the second half replaces utility-scale PV at a much higher cost. The increase of offshore wind, utility-scale PV, and rooftop PV shares always reduces expected land requirements of fully renewable electricity systems, albeit at different cost.

4.3.3 Cost penalties of 20% or less are most likely even for low land requirements

Uncertainty in technology cost and land requirements leads to high uncertainty in the cost penalties for renewable electricity with lower land requirements. To ensure land requirements are below 1% of total European land, cost penalties can be as large as 40%, but are most likely below 20% for all supply technology options (see Figure 4.5). For offshore wind and utility-scale PV a cost penalty below 20% can be expected in 75% of the cases. In a quarter of all cases, there is no cost penalty necessary at all, because the cost-optimal case has land requirements of 1% or lower. With lower thresholds, cost penalties become more likely and also larger. For a threshold of 0.5% of European land, a cost penalty of 20% is still more likely for the more cost-effective technologies offshore wind and utility-scale PV.

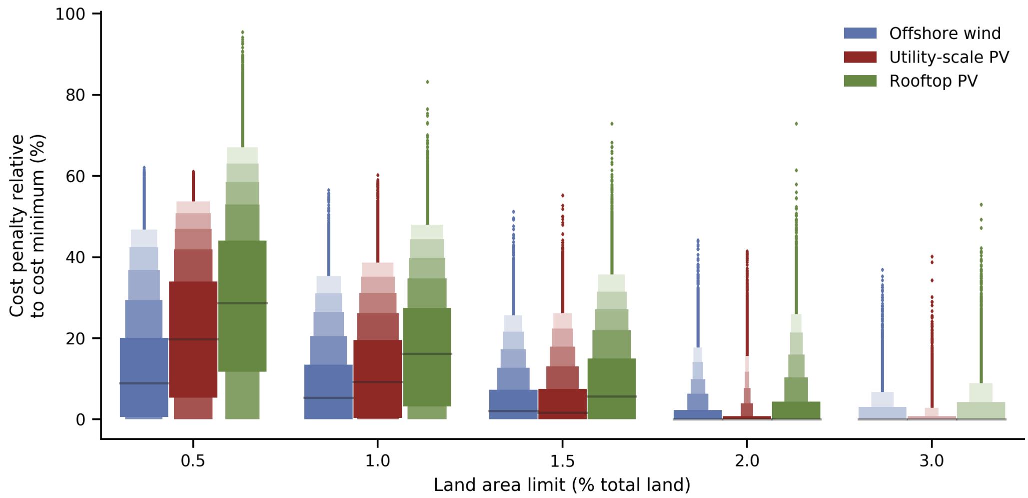

Figure 4.5: Resulting cost penalties to ensure land thresholds. Cost penalties arise from higher than cost-minimal shares of one of three supply technologies: offshore wind, utility-scale PV, or rooftop PV. The uncertainty distribution of cost penalties is displayed using letter-value plots. Letter-value plots are an extension to boxplots for large data. Dark grey lines indicate the median value of the cost penalties, and the widest boxes above and below the median visualise the 25–75% quantiles. Each following box contains half as many observations as the box closer to the median. The extreme 1% of the observations are considered outliers and marked with rhombs.

Uncertainty does not alter the order of cost-effectiveness of the three supply technologies with low land requirements: rooftop PV is always the least cost-effective technology. Offshore wind is most cost-effective, but only when large amounts of onshore wind are to be replaced (see land area thresholds of 1% or smaller in Figure 4.5). In these cases, offshore wind is more cost-effective than utility-scale PV. For medium land thresholds (1.5%), expected value of cost and its distribution are nearly the same for both technologies. Above that, as long as land area is to be reduced only little, utility-scale PV is the most cost-effective option.

4.3.4 Low land requirements require low shares of onshore wind

While land needs of supply technologies are uncertain, onshore wind is in any case the technology with the highest requirements for land if spacing is included. Offshore wind, utility-scale PV, and rooftop PV are therefore no-regret options to reduce the spatial extent of renewable electricity generation on land. In 50% of the cases, a land threshold of 1% of total European land can only be reached if the capacity share of onshore wind is 40% or lower (see Figure 4.6), and if there are no additional land requirements from utility-scale PV. When utility-scale PV exists as well, onshore wind capacity must be even lower, and if utility-scale PV is the only alternative, onshore wind capacity must be as low as 10%. Renewable electricity with low requirements for land can only be reached by low shares of onshore wind.

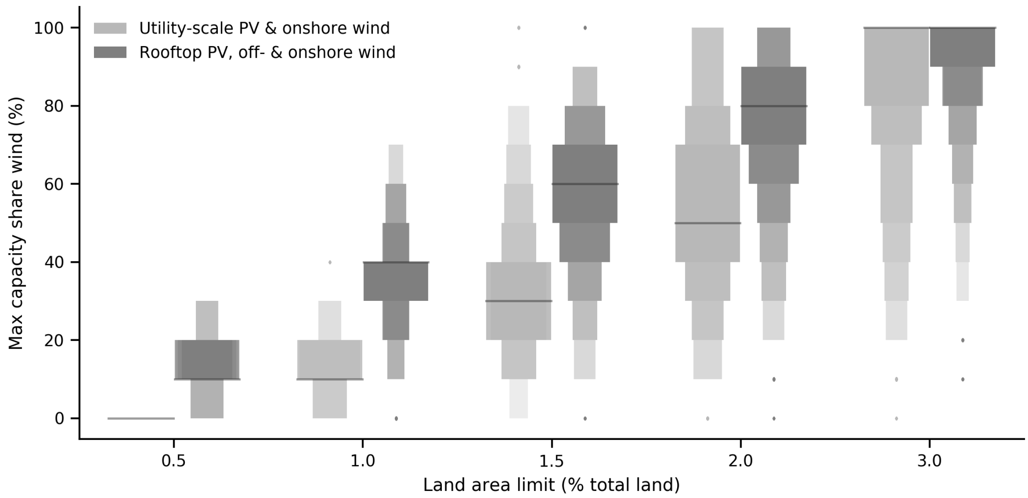

Figure 4.6: Maximal capacity shares of onshore wind to ensure land thresholds. Visualised shares are the maximum shares among system designs with only utility-scale PV or only rooftop PV and offshore wind in addition to onshore wind and given uncertainty. Uncertainty stems from the uncertainty of how much land onshore wind and utility-scale PV require. The uncertainty distribution of capacity shares is displayed using letter-value plots. Letter-value plots are an extension to boxplots for large data. Dark grey lines indicate the median value of the cost penalties, and the widest boxes above and below the median visualise the 25–75% quantiles. Each following box contains half as many observations as the box closer to the median. The extreme 1% of the observations are considered outliers and marked with rhombs.

4.3.5 Storage and flexible generation require small amounts of land

Systems with different shares of solar and wind capacity require different balancing capacity in terms of electricity storage, bioenergy, and transmission. Balancing needs are moderate for cases with balanced mixes of supply technologies (Figure 4.7). When supply is strongly biased towards one technology, flexibility needs rise, and in some cases they rise sharply. Exclusively- or almost exclusively-solar cases require high amounts of short-term (battery) electricity storage. In extreme cases, storage capacities alone are able to fulfil the largest part of Europe's peak demand. Short-term storage capacities in these cases are combined with very high magnitudes of bioenergy capacity of up to 50% of peak demand to balance solar's seasonal fluctuations. Cases with mainly wind require much less bioenergy capacity and short-term storage capacity, but more long-term storage capacities to balance wind fluctuations between days and weeks. In addition, they require around 2.5 times larger international transmission capacity than solar systems. While some of these numbers are very high, especially for cases with single supply technologies, there is no reason to believe these balancing capacities could not be built.

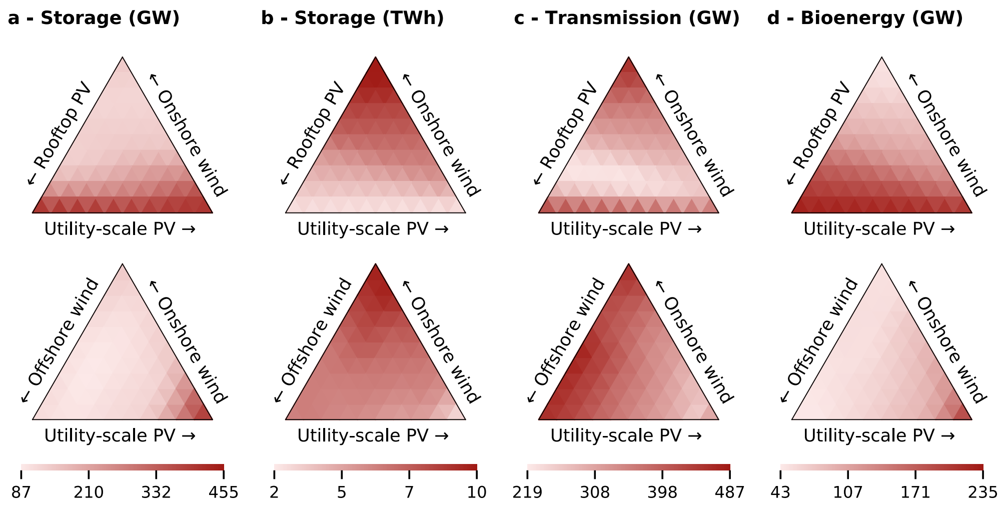

Figure 4.7: Flexibility needs of fully renewable electricity systems with all possible shares of three different supply technologies. All designs are exclusively supplied from hydroelectricity of today's capacity and different shares of three additional technologies each: onshore wind and utility-scale PV in all cases, combined with either rooftop PV (top row) or offshore wind (bottom row). Each technology is varied from 0–100% of the total capacity of the three technologies. **a,b,c,d,** Storage power capacity (**a**), storage energy capacity (**b**), international transmission capacity (**c**), and bioenergy capacity (**d**). Not shown are hydroelectricity capacities which are kept constant in all cases (36 GW run of river, 103 GW / 97 TWh reservoirs, 54 GW / 1.3 TWh pumped hydro storage).

Balancing capacities require land as well and thus add to the land requirements of the entire electricity system. The transmission grid will likely require a significant amount of land. In its current state, it uses an estimated 0.3% of total land (see Methods). For the system designs in this study I can not determine land requirements of the transmission grid, as the spatial resolution is too low to generate estimations.

The land requirements of all other balancing technologies are very small, however. When considering 10^5 Wh/m^2 for battery storage capacity, a conservative 6,000 Wh/m^2 for hydrogen storage capacity, and 10^4 W/m^2 for bioenergy capacity (see Methods), total land requirements of all three flexibility technologies are always below 1,800 km^2 (0.04% of total European land). Within this estimate, the by far largest contribution comes from hydrogen, for which I use an upper-bound estimation (stored uncompressed in overground tanks). If hydrogen is stored land efficiently in underground caverns, flexibility needs of all three technologies can rise by orders of magnitude without making a significant contribution to total land requirements of fully renewable electricity systems.

4.4 Discussion

I show that there is a trade-off between land requirements and cost of fully renewable electricity in Europe, but that reducing land requirements by changing supply-side technologies does not necessarily lead to substantial cost penalties. The expected land requirements of a system design with minimal expected cost is 97,000 km^2 (2% total European land). Such a low-cost system is supplied, apart from hydroelectricity and bioenergy from residuals, only from onshore wind farms and utility-scale photovoltaics (PV). Its expected land requirements can be reduced by replacing onshore wind with offshore wind, utility-scale PV, or rooftop PV. Offshore wind is the most cost-effective option of these three possibilities. It decreases cost-minimal land requirements by 50% for an expected cost penalty of only 5%. Utility-scale and rooftop PV lead to the same effect for cost penalties of 10% and 17%. All three technologies can reduce land requirements more than 50% for higher cost penalties by replacing larger amounts of onshore wind capacity.

Because cost and land requirements of wind and solar power are not known with certainty, total system cost and total land requirements of renewable electricity supply in Europe is uncertain as well. Ensuring land requirements lower than 1% of total European land (50% of the cost-minimal case) can thus require cost penalties as large as 40%. Despite these uncertainties, three main findings are robust: First, onshore wind always requires the most amount of land and thus a switch to any other technology to reduce land is a no-regret option. Second, offshore wind is always the most cost-effective option, followed by utility-scale PV, and rooftop PV. Third, reducing land requirements of fully renewable electricity in Europe does likely not come with high cost: cost penalties of 20% or less are most likely for a system with low land requirements of 1% of European land through sufficient shares of offshore wind, utility-scale PV, or rooftop PV.

Considering all uncertainty and all possible system designs, land requirements of solar and wind power are in the range of 0–3% of total European land. Significant contributions to the land needs of electricity supply can be expected from the transmission grid and hydroelectricity (~0.5% and <1%, see Methods). The total land requirements of fully renewable electricity is thus likely within the range of 1.5–4.5%.

4.4.1 Comparison to previous studies

Comparing my results to findings from previous studies shows that there is some uncertainty about the potential of rooftop PV to reduce land requirements, as well as some uncertainty about the land requirements and therefore cost-effectiveness of utility-scale PV. There are no findings, however, that question the potential or the cost-effectiveness of offshore wind.

First, rooftop PV generates up to 1,800 TWh/yr in this study. Other estimations for the potential of photovoltaics on roofs and facades are lower: 680 TWh/yr for only rooftop PV (Bódis, Kougias, Jäger-Waldau, et al., 2019) and 1200–2100 TWh for rooftop PV and PV on façades (Ruiz et al., 2019). Should the lower estimations be correct, very high shares of rooftop PV as considered in this study may not be possible. In that case, rooftop PV could reduce smaller amounts of land requirements only. High shares of rooftop PV are in any case less attractive due to high cost and high balancing requirements, as I show in my results.

Second, up to 1,800 TWh/yr are generated by utility-scale PV when its capacity share is the highest. While this does not exceed potential estimations in the literature (Capellán-Pérez et al., 2017; Ruiz et al., 2019), there are conflicting estimations about how much land utility-scale requires (see also Methods). While this study uses measurements from ref. (ZSW & Bosch & Partner, 2019), ref. (de Castro et al., 2013) states that areas larger than the fenced areas of PV farms must be considered, leading to capacity shares two times smaller than in this study. Whether such areas should be included is questioned (Smil, 2015). Using their capacity shares would reduce the cost-effectiveness of utility-scale PV.

Third, with potential estimations as large as 40,000 TWh/yr (~10 times current electricity demand) (Caglayan et al., 2019) or even 50,000 TWh/yr (IEA, 2019), the potential of offshore wind to reduce land requirements is not questioned by previous findings in the literature.

Lastly, one study finds total land requirements of a system based on PV which are more than ten times larger than in this study: 8% of total European land (Capellán-Pérez et al., 2017). The large deviation can be explained mainly by two differences: First, by the above-mentioned lower capacity densities given in ref. (de Castro et al., 2013). Second, by their finding that large overcapacities are necessary to handle renewable fluctuations: in the most extreme case of Finland, this leads to 7 times the required capacity. In my study, fluctuations are handled by continental balancing through the transmission grid and by flexible generation from bioenergy. As a result, I find only three countries require overcapacities, and overcapacities never exceed 1.15 times the required capacity. The handling of renewable fluctuations explains the largest part of the different findings of the two studies. This shows the importance of an analysis on the system level, including not only supply but also balancing.

4.4.2 Limitations and outlook

The high level perspective on land requirements in this study allows to understand the full spatial extent of electricity supply infrastructure on European land

and its trade-off with cost. Land requirements of the different technologies, however, are not always directly comparable. For example, while solar photovoltaics does not allow for any other land use – at least not as long as agrophotovoltaics is unavailable at large scale (Weselek et al., 2019) – the vast spacing between wind turbines does allow for agriculture. Thus, the two technologies compete differently with other uses of land. Offshore wind of course requires no land, but competes with other uses of offshore areas. Because I analyse total land requirements in this study, I cannot account for these qualitative differences. However, I mitigate this limitation by making options to reduce land requirements technology-specific.

Further, not only total land requirements are important, but also the exact location and technical parameters: wind turbines impact landscapes stronger when they are larger and when they are placed on exposed locations like hilltops. Analysing the impact of renewable electricity on landscapes has not been done on this level of detail so far.

4.4.3 Conclusion

My findings show that supply technology choice is an effective way to reduce land requirements of fully renewable electricity systems in Europe. Systems with vastly different land requirements can be designed, and their cost must not vary much as long as land requirements are reduced cost-effectively. Instead of relying strongly on onshore wind, which is likely the cost-minimal solution, electricity can be generated offshore at large scale and be transported to demand centres using a sufficient transmission grid. The expansion of both, onshore wind farms and transmission grid can be limited by alternatively generating solar electricity locally. Such a solar-centred electricity supply is enabled by flexible generation from bioenergy to cope with seasonal fluctuations. These findings increase the solution space for a European energy transition and allow to integrate more diverse stakeholder positions than is possible with cost minimised electricity system designs.

5 Discussion

Conflicts about how fully renewable electricity in Europe should look like may lead to political barriers, which have the potential to slow or even stop the energy transition. In this thesis, I assessed the existence of compromise solutions, which may not be ideal in any logic but include aspects of all. Such compromise solutions may be acceptable to proponents of all logics and thus may be capable of relieving conflicts and enabling a faster energy transition. My assessments led to both empirical and methodological insights, which I discuss in the following alongside limitations of my contributions and a discussion of the implications.

5.1 Key empirical and methodological contributions

Empirically, the findings in *contribution I* show that self-sufficiency on small geographic scales is possible with electricity generated from only solar and wind sources, though there are limits. While the potential of each assessed technology is sufficient to cover European electricity demand, the population share for which self-sufficiency is possible decreases with geographic scale. On the municipal scale, self-sufficiency is possible for only 75% of the population. Where self-sufficiency is not possible, electricity must be imported from surrounding or distant municipalities. Thus, a pure form of the demand-driven logic is not possible everywhere in Europe, but forms with limited trade are.

Empirical insights of *contribution II* concern the economic viability of the cost- and demand-driven allocation logics. In its purest form, the cost-driven logic trades off independence for cost by supplying all of Europe from the most economically efficient locations, leaving all other places as mere importers of electricity. The demand-driven logic resolves the same trade-off in the opposing manner, and trades off cost for independence. This dichotomy appears to be difficult to dissolve. A compromise solution respecting both logics is within reach with a better understanding of the drivers of cost, as our results show. In fact, cost is driven primarily by the geographic scale at which renewable fluctuations are balanced and less by the scale at which electricity is generated. Respecting this observation, it is possible to design electricity supply acceptable to proponents of both logics. Such a compromise solution would be supplied locally, but renewable fluctuations would be handled on larger geographic scales. For this solution to be successful, proponents of the demand-driven logic would need to forego independent, local balancing, and proponents of the cost-driven logic would need to accept small cost penalties.

Finally, findings in *contribution III* offer options to integrate the landscape-driven logic, as well. The main finding of this contribution is that electricity systems with highly different requirements for land are possible and that cost penalties to reduce land requirements must not be large. Electricity supply following the landscape-driven logic is thus possible. The findings furthermore show that compromises with the other logics exist as well. First, solutions with low land requirements must not conflict at all with the demand-driven logic. This requires the proper choice of technology: while all three technologies – offshore wind, utility-scale PV, and rooftop PV – have the potential to reduce land requirements, the latter two are fully compatible with the landscape- and demand-driven logics. Second, the trade-off between cost and land means that solutions with low land requirements do not follow the cost-driven logic. However, cost penalties are small – as low as 5% for large reductions in land requirements – which allows for designing compromise solutions that incorporate aspects of both the landscape- and cost-driven logics.

In addition to these empirical findings, my research offers **methodological insights**. In the following, I discuss insights gained from the use of satellite images in contribution I, uncertainty analyses methods in contributions II and III, and computational workflows in all contributions.

First, the method I apply in *contribution I* derives rooftop PV generation potentials from high-resolution satellite and aerial images, which has not previously been possible. This allows for increasing the fidelity of estimations and increases our understanding of exactly how much electricity can be generated on Europe's rooftops. In addition to the methods to derive potentials of all other technologies, this shows the usefulness of general-purpose geospatial data on high resolution for energy research.

Second, applying several uncertainty analysis methods, some of which have never been applied in energy system analysis, reveals their usefulness and necessity for empirical research in this field. Parametric uncertainties of model inputs can be large and affect relationships between the inputs and outputs under investigation. Only with methods such as those we applied is it possible to demonstrate whether relationships are robust towards input uncertainty. Furthermore, ignoring uncertainties may be a smaller problem if expected input values lead to expected output values. This is the case only for linear or almost-linear models, however. Our results show that this is not the case for our model of the electricity system: the expected output can differ from the output resulting from the expected input. While thorough uncertainty analysis is rarely applied in energy system research today, the methodological insights of my contributions indicate that it should instead become a standard.

Finally, dealing with the high spatial and temporal resolution of renewable electricity systems and handling uncertainty at the same time leads to complex analyses. This complexity has the potential for technical mistakes to be introduced into the analyses and jeopardise transparency and reproducibility. To overcome these issues, I applied a workflow management system which makes workflow steps explicit and automates the analysis process. This method proved highly useful, especially for updating and repeating parts of the analyses without introducing errors and for tracing back assumptions. This kind of method is not standard today in energy research, but with energy system analyses covering an increasing number of aspects in ever greater depths, it will become indispensable to ensure reliability and transparency.

5.2 Limitations and outlook

The methodological insights also highlight limitations of my contributions, which serve as an outlook for further research. I discuss the three most important limitations in the following: fidelity of potential estimations, uncertainty estimation of model inputs, and integrated energy system analysis.

First, the fidelity of estimations of renewable generation potentials is not yet sufficiently high. Due to missing or conflicting data, not all necessary aspects can be considered. For example, we do not know enough about the spatial variability of orientation, size, availability, and shading of roof spaces in Europe. In addition, we do not know enough about the power density of solar and wind power, including about how it changed in the past. This leads to high uncertainty about how much electricity can be generated in Europe and how much space it requires. More research on available roof space and power densities is necessary to improve the fidelity of renewable potential estimations.

Second, my findings depend strongly on input uncertainty. Any flaw in input uncertainty is fed forward to my findings. For example, if minimal cost of bioenergy is falsely too high, minimal total system cost will be too high, as well. Any analysis is thus only as good as the fidelity of its input. Partially because these kinds of analyses are not the norm in energy research, we do not know enough about the uncertainty. Further research is necessary to understand parametric uncertainty of the most important technology parameters to improve insights derived from energy system analysis.

Finally, I focus on the electricity sector and current electricity demand in this thesis while ignoring all other energy demands. The electricity sector plays a dominant role in fighting climate change, because technologies to decarbonise it are readily available and because other energy demands can be electrified. I do not quantitatively assess the latter for two reasons. First, some aspects of electrification are highly uncertain – not due to parametric uncertainty which I discuss above, but due to unknown political decisions. Second, an integrated analysis presents a computational challenge. The high spatial resolution and the thorough parametric uncertainty analysis of my research push the barrier of what is computationally possible today, even without considering the electrification of other energy demands.

The impact of the electrification of the heat and mobility sectors on my findings can be anticipated qualitatively. Generally, their electrification would increase the electricity demand – in extreme projections by up to 150% (European Commission, 2018) – and include more options to balance supply and demand (Brown et al., 2018). This would likely impact the main findings of my three research contributions in the following way. First, it would negatively impact the technical possibility of the demand-driven logic. While even in extreme cases Europe and many countries would retain their potential for self-sufficiency, some countries and more regions and municipalities than before would require imports. The demand-driven logic would still work, but it would be technically more restricted. Second, additional options for balancing would decrease the importance of transmission capacities (Brown et al., 2018), and therefore increase the economic attractiveness of stricter versions of the demand-driven logic (see also Appendix [B3][B3: Effect of model simplifications]) and decrease the economic advantage of the cost-driven logic. Third, additional options for balancing seasonal fluctuations would allow solar power to more cost-effectively reduce land requirements, and thus, cost penalties in these cases would be lower than quantified here. This would increase the solution space of the landscape-driven logic. Overall, further research is needed to quantitatively confirm these anticipated impacts. The model surrogate method we introduce in *contribution II* may prove useful for this computationally difficult task.

5.3 Implications

In summary, the empirical insights of my research show not only that fully renewable electricity in Europe is technically feasible and economically viable but also that many technically feasible and economically viable options for entirely renewable supply exist. This includes electricity supply based on the three allocation logics. Infrastructure allocation can be cost-driven, with electricity supplied from large farms at locations with the best meteorological conditions in a system that relies on strong cooperation and trade. Infrastructure allocation can also be demand-driven, with electricity supplied from within local communities. Finally, it can be landscape-driven, with electricity generation occurring largely off the shore or on rooftops. Because techno-economic bounds are broad, the question of where and which infrastructure should be built is largely a question about the impacts that the infrastructure has on landscapes, societies, and economies. The answer to this question is normative.

More specifically, I show that the wealth of opportunities includes electricity supply options that integrate aspects of all conflicting logics and that necessary trade-offs must not be strong. Such compromise solutions have not lowest, but low cost, not highest, but high independence, and not lowest, but low land requirements and therefore combine preferences of the cost-driven, demand-driven, and landscape-driven logics. One example is a system supplied largely by solar power on the regional scale but with continental-scale balancing of renewable fluctuations. Another example is a system supplied largely from offshore wind and solar power on the national scale, again with continental-scale balancing. Such solutions are not ideal for any logic, but since they include aspects of each logic and necessary trade-offs are weak, they may be acceptable to all. This enables proponents of all logics to relate to these forms of electricity supply and integrates their voices into the societal change process that is the energy transition.

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Appendix A: Supplementary material to contribution I

A1 Code and data

The code and reproducible workflow used to perform this analysis is available online (Tröndle, 2019). Furthermore, the resulting data is available online as well (Tröndle, Pfenninger, & Lilliestam, 2019a).

A2 Spatial and spatio-temporal data sources

Table A1 lists all spatial and spatio-temporal data sources used in this study, together with their most important technical characteristics and their source.

Table A1: Spatial and spatio-temporal data sources used in this study.

Name	Type	Spatial resolution	CRS	Format	Source
Nomenclature of Territorial Units for Statistics (NUTS)	vector	1:1 Million	EPSG: 4258	Shapefile	eurostat (2015)
Global Administrative Areas Database (GADM)	vector	•	EPSG: 4326	GeoPackage	GADM (2018)
Local Administrative Unit 2 (LAU2)	vector	1:1 Million	EPSG: 4258	Shapefile	eurostat (2015)
Exclusive Economic Zones (EEZ)	vector	•	EPSG: 4326	Shapefile	Claus et al. (2018)
GlobCover 2009	raster	10 "	EPSG: 4326	GeoTIFF	European Space Agency (2010)
NASA Shuttle Radar Topographic Mission (SRTM)	raster	3 "	EPSG: 4326	GeoTIFF	Reuter et al. (2007)

Name	Type	Spatial resolution	CRS	Format	Source
Global Multi-Terrain Elevation (GMTED)	raster	7.5 "	EPSG: 4326	GeoTIFF	Danielson & Gesch (2011)
ETOPO1	raster	1 '	EPSG: 4326	GeoTIFF	Amante & Eakins (2009)
World Database on Protected Areas	vector	•	EPSG: 4326	Shapefile	UNEP-WCMC & IUCN (2018)
European Settlement Map 2017	raster	6.25 m	EPSG: 3035	GeoTIFF	Ferri et al. (2017)
sonnendach.ch	vector	•	EPSG: 2056	GeoPackage	Swiss Federal Office of Energy (2018)
Renewables.ninja	spatio-temporal	50 km	EPSG: 4326	NetCDF4	Staffell & Pfenninger (2016) Pfenninger & Staffell (2016)
Open Power System Data	spatio-temporal	national	•	CSV	Open Power System Data (2018)
Global Human Settlement Population Grid	raster	250 m	ESRI: 54009	GeoTIFF	JRC & CIESIN (2015)

A3 Roofs for PV

Table A2 shows the share of roof categories from the sonnendach.ch dataset, which we assume to be representative for all countries in our study and which we thus use Europe-wide.

Table A2: Area share of roof categories used Europe-wide, based on data from Switzerland in the sonnendach.ch dataset (**Swiss Federal Office of Energy**, 2018).

Orientation	Average tilt [%]	Share of roof areas [%]
E	18.2	4.9
E	25.9	4.0
E	32.9	3.7
E	43.5	4.0
N	17.3	4.8
N	24.9	4.2
N	32.4	4.6
N	43.7	4.6
S	18.1	5.6
S	25.4	3.6
S	32.4	4.7
S	43.1	4.3
W	18.1	5.2
W	25.4	3.5
W	32.3	4.2
W	43.5	4.0
flat	0.0	30.2

A4 Technical potential

Based on the input data, we determine the technical potential of renewable electricity for all Europe, all countries, all regions, and all municipalities in Europe. Table A3 shows the technical potential for all countries in Europe. This data, and data on the continental, regional, and municipal levels is available for download, see above.

Table A3: Technical potential of open field PV, roof mounted PV, onshore wind turbines, and offshore wind turbines on the national scale.

id	Roof mounted PV [TWh/yr]	Open field PV [TWh/yr]	Onshore wind [TWh/yr]	Offshore wind [TWh/yr]	Demand [TWh/yr]
AUT	86.5	1026.5	307.0	0.0	63.6
BEL	89.5	466.2	101.0	172.0	87.2
BGR	91.7	4802.9	531.0	195.0	38.8
HRV	74.3	1722.4	316.7	572.8	17.9
CYP	29.8	271.3	23.8	39.0	4.5
CZE	99.6	2634.4	492.6	0.0	66.1
DNK	60.9	1300.6	157.8	4921.3	32.5
EST	12.7	979.0	581.8	1087.5	8.3
FIN	43.2	4349.7	4617.8	2188.5	83.4
FRA	820.0	19298.3	1721.2	2609.2	477.1
DEU	739.0	9608.2	1467.1	3281.6	493.3
GRC	101.4	3234.8	709.2	905.1	51.6
HUN	106.4	5989.3	237.7	0.0	43.0
IRL	31.3	2358.4	451.1	1193.4	27.7
ITA	495.9	6623.4	1007.8	1169.3	291.4

id	Roof mounted PV [TWh/yr]	Open field PV [TWh/yr]	Onshore wind [TWh/yr]	Offshore wind [TWh/yr]	Demand [TWh/yr]
LVA	15.6	1521.4	635.0	761.2	7.2
LTU	30.8	1984.1	374.5	178.7	11.7
LUX	4.8	63.7	18.2	0.0	4.3
NLD	147.4	640.4	72.8	3961.0	113.8
POL	251.0	11143.3	1773.0	803.8	168.4
PRT	155.6	3544.0	448.5	301.6	49.6
ROU	201.9	11249.3	1045.5	396.2	60.0
SVK	56.9	1466.9	335.4	0.0	29.7
SVN	24.3	137.5	103.6	4.8	13.2
ESP	330.9	28339.7	2876.2	967.7	252.8
SWE	63.5	6557.4	5897.5	3253.0	138.1
GBR	339.0	6581.9	2080.8	9547.5	306.5
ALB	17.2	416.5	110.2	50.1	7.1
BIH	42.8	786.6	326.6	0.3	12.8
MKD	13.4	635.3	101.2	0.0	7.0
MNE	8.4	151.6	75.3	7.8	3.4
NOR	22.3	7070.6	2717.4	2350.7	132.9
SRB	90.7	2802.5	304.5	0.0	39.8
CHE	66.7	162.2	52.1	0.0	59.7

A5 Technical-social potential

Based on the input data, we determine the technical-social potential of renewable electricity for all Europe, all countries, all regions, and all municipalities in Europe. Table A4 shows the technical-social potential for all countries in Europe. This data, and data on the continental, regional, and municipal levels is available for download, see above.

Table A4: Technical-social potential of open field PV, roof mounted PV, onshore wind turbines, and offshore wind turbines on the national level.

id	Roof mounted PV [TWh/yr]	Open field PV [TWh/yr]	Onshore wind [TWh/yr]	Offshore wind [TWh/yr]	Demand [TWh/yr]
AUT	86.5	9.1	34.3	0.0	63.6
BEL	89.5	6.1	9.8	11.6	87.2
BGR	91.7	48.1	71.1	13.1	38.8
HRV	74.3	29.2	29.6	42.8	17.9
CYP	29.8	8.8	3.2	3.6	4.5
CZE	99.6	20.3	71.6	0.0	66.1
DNK	60.9	15.6	27.1	405.0	32.5
EST	12.7	9.8	62.0	75.7	8.3
FIN	43.2	292.8	402.1	180.0	83.4
FRA	820.0	279.8	340.6	127.6	477.1
DEU	739.0	104.2	152.2	187.7	493.3
GRC	101.4	46.0	68.2	53.7	51.6
HUN	106.4	21.9	102.0	0.0	43.0
IRL	31.3	198.0	30.6	89.4	27.7
ITA	495.9	63.7	141.1	89.8	291.4

id	Roof mounted PV [TWh/yr]	Open field PV [TWh/yr]	Onshore wind [TWh/yr]	Offshore wind [TWh/yr]	Demand [TWh/yr]
LVA	15.6	7.3	77.7	54.9	7.2
LTU	30.8	8.1	60.6	10.8	11.7
LUX	4.8	1.4	0.8	0.0	4.3
NLD	147.4	23.2	13.2	296.7	113.8
POL	251.0	39.2	212.8	45.1	168.4
PRT	155.6	129.4	60.2	17.5	49.6
ROU	201.9	45.1	236.8	16.6	60.0
SVK	56.9	9.5	38.8	0.0	29.7
SVN	24.3	1.6	3.9	0.0	13.2
ESP	330.9	649.8	453.2	53.6	252.8
SWE	63.5	433.2	511.0	219.4	138.1
GBR	339.0	252.1	188.7	440.2	306.5
ALB	17.2	3.8	13.1	4.6	7.1
BIH	42.8	18.8	41.1	0.0	12.8
MKD	13.4	13.0	13.9	0.0	7.0
MNE	8.4	2.3	8.5	0.8	3.4
NOR	22.3	530.5	235.9	217.7	132.9
SRB	90.7	17.1	71.7	0.0	39.8
CHE	66.7	6.5	5.2	0.0	59.7

Appendix B: Supplementary material to contribution II

B1: Code and data

The code and reproducible workflow used to perform this analysis is available online (Tröndle, Pfenninger, & Marelli, 2020). Furthermore, the resulting data is available online as well (Tröndle & Marelli, 2020).

B2: Impact of net imports into supply area on cost

To confirm the inferior impact of supply options on total cost, we assess the cost of nine further cases, in which we relax the supply scale by permitting net imports to satisfy national or regional electricity demand. This relaxation has a small impact on cost (see Figure B1), with 10 percentage points or less cost reduction between net self-sufficiency (0 net imports, cases from Figure 3.1) and allowing up to 30% net imports. This reinforces the finding from Figure 3.1: geographic scale has a particularly large impact on cost because of the possibilities for balancing, not mainly because of supply options.

B3: Effect of hydropower model choices on our results

The way in which we model hydropower generation in Europe leads to peculiarities in results on the regional scale. Here, we find the lowest and the highest system cost in regions with large hydropower installations. These cost peculiarities are consequences of two model design choices: we keep hydropower capacities fixed at today's level and we assume they are amortised. In the following, we justify these two model design choices and discuss their relevance for our results.

We assume hydropower capacities are amortised to avoid the need to model overnight cost. Overnight cost of hydropower capacities can vary strongly between projects and are thus difficult to model. Ignoring overnight cost can lead to low levelised cost of electricity in regions with large hydropower capacities. Cost is particularly low when dams provide local flexibility and other forms of more expensive flexibility provision can be avoided. Thus, our model choice leads to low cost in some regions and it also leads to slightly optimistic absolute system cost. But because we fix capacities to current levels for all Europe in all cases, the ignored overnight cost imply no benefit to any case and thus do not affect relative cost.

We fix hydropower capacities to current levels because significant capacity expansion in Europe is unlikely (Lacal Arantegui et al., 2014). In regions in which hydropower generation exceeds local electricity demand largely, this model choice can lead to high cost in the regional-scale case. However, on average, the impact is small. While on the continental scale levelised cost of electricity of hydropower ranges from 31 to 55 EUR per MWh, it ranges from 33 to 61 EUR per MWh on the regional scale. In fact, 35% of the hydropower potential on the regional scale is curtailed. This corresponds to 2% of total electricity system cost. Thus, if we allowed for capacity reduction on the regional scale, its cost could reduce by up to 2%. This magnitude has no significant affect on our main results.

B4: Effect of model simplifications

There are three aspects which our analysis does not consider and which may impact our findings. Some are likely to increase attractiveness of small-scale systems, others are likely to increase attractiveness of large-scale systems.

Most importantly, we do not consider flexibility from electricity demand or from electrifying the heat and transport sectors. These additional flexibilities may be especially beneficial for smaller-scale systems, whose flexibility options are more limited and expensive. However, large electricity systems can and will benefit as well and our sensitivity analysis shows that cost differences are driven largely by the cost of bioenergy; a technology mostly used to balance seasonal fluctuations of solar generation. Only if additional flexibilities can balance seasonal fluctuations, a significant impact on system cost can be expected. This is likely not the case for demand flexibility (Aryandoust & Lilliestam, 2017) or transportation (Brown et al., 2018), but it may be possible by electrifying the heat sector (Brown et al., 2018).

Furthermore, we do not consider ancillary services for the distribution and transmission grids. The provision of ancillary services may be easier, i.e. less costly, for system layouts as we found them for smaller electricity systems, because not only generation but also support infrastructure is more homogeneously dispersed and thus able to provide services like frequency control or black-start everywhere. However, there is no reason to believe that this would change system cost and therefore relative system cost significantly (T. W. Brown et al., 2018).

We also do not model the distribution grid in any way. The cost of the distribution grid is likely to be higher for smaller systems where generation is dispersed more strongly with substantial amounts of generation from roof mounted PV embedded within the distribution grid. However, technical potentials of wind and utility-scale PV are high enough in most regions in Europe so that roof mounted

PV is rarely necessary. Thus, cost of the distribution grid may be higher for smaller scales, but only if roof mounted PV is prioritised over utility-scale PV.

B5: System cost in cases including net imports

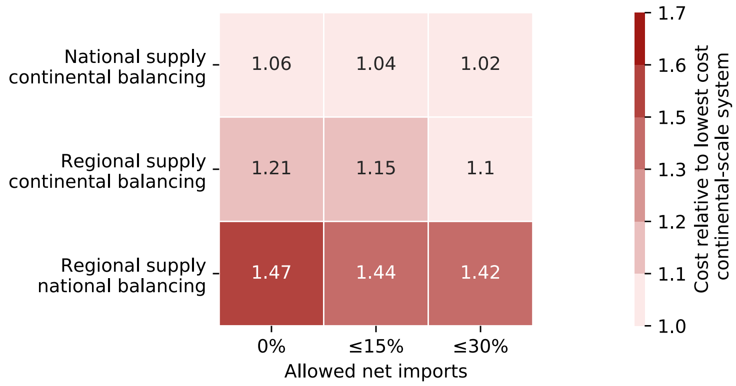

Figure B1: System cost of nine electricity systems in Europe with national or regional net supply, and continental or national balancing, relative to lowest cost, continental-scale system. Cost of variations of three cases from Figure 3.1 in which net imports into the national or regional supply area are allowed to certain degrees (x-axis), from no net imports (0%, corresponds to cases from Figure 3.1) to imports covering up to 30% of national or regional electricity demand. Cost are relative to the entirely continental case in Figure 3.1.

B6: Total Sobol' indices

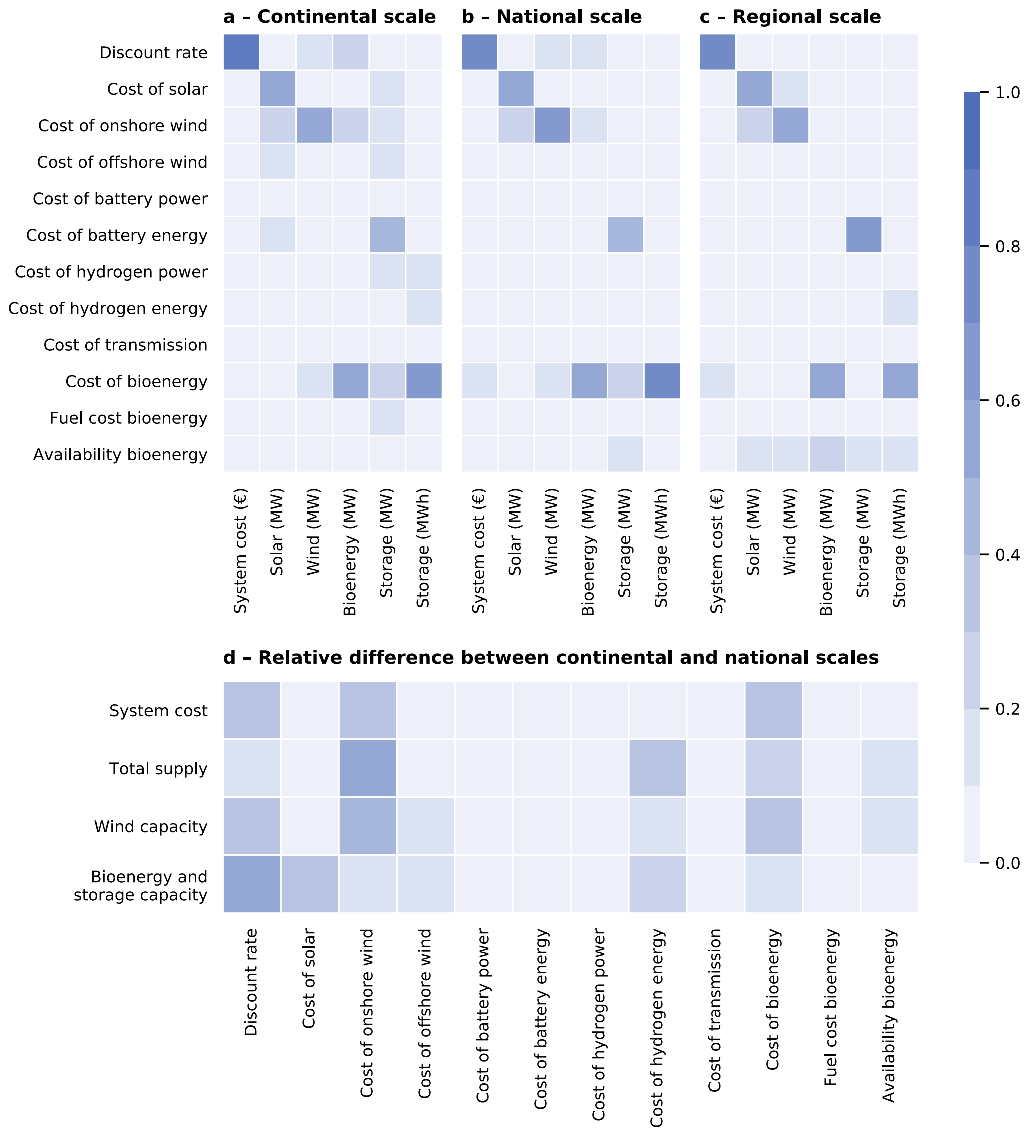

Figure B2: Total Sobol' indices for combinations of all considered input uncertainties and selected model outputs of entirely continental-, national-, and regional-scale electricity systems. a,b,c, Sobol' indices of input parameters considering total system cost and total installed capacities (x-axis) of the continental- (**a**), national- (**b**), and regional-scale (**c**) systems. The y-axis shows the twelve input parameters included in the uncertainty analysis. **d,** Sobol' indices of input parameters considering difference in system cost between the continental- and national-scale systems. The x-axis shows the twelve input parameters included in the uncertainty analysis. The y-axis shows the model-wide result variables for which continental to national scale differences are compared.

B7: First-order Sobol' indices

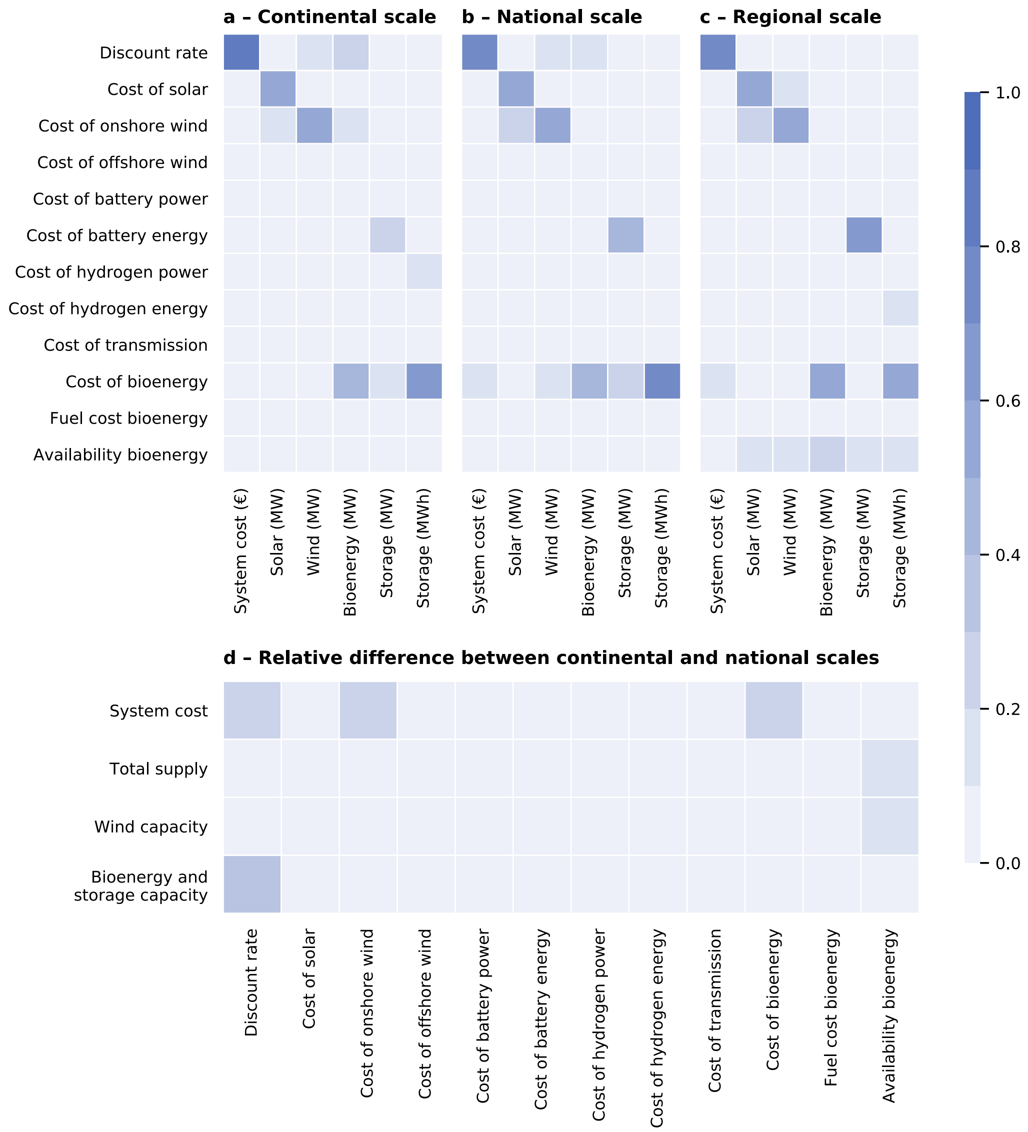

Figure B3: First-order Sobol' indices for combinations of all considered input uncertainties and selected model outputs of entirely continental-, national-, and regional-scale electricity systems. a,b,c, Sobol' indices of input parameters considering total system cost and total installed capacities (x-axis) of the continental- (**a**), national- (**b**), and regional-scale (**c**) systems. The y-axis shows the twelve input parameters included in the uncertainty analysis. **d,** Sobol' indices of input parameters considering difference in system cost between the continental- and national-scale systems. The x-axis shows the twelve input parameters included in the uncertainty analysis. The y-axis shows the model-wide result variables for which continental to national scale differences are compared.

B8: Difference Sobol' indices

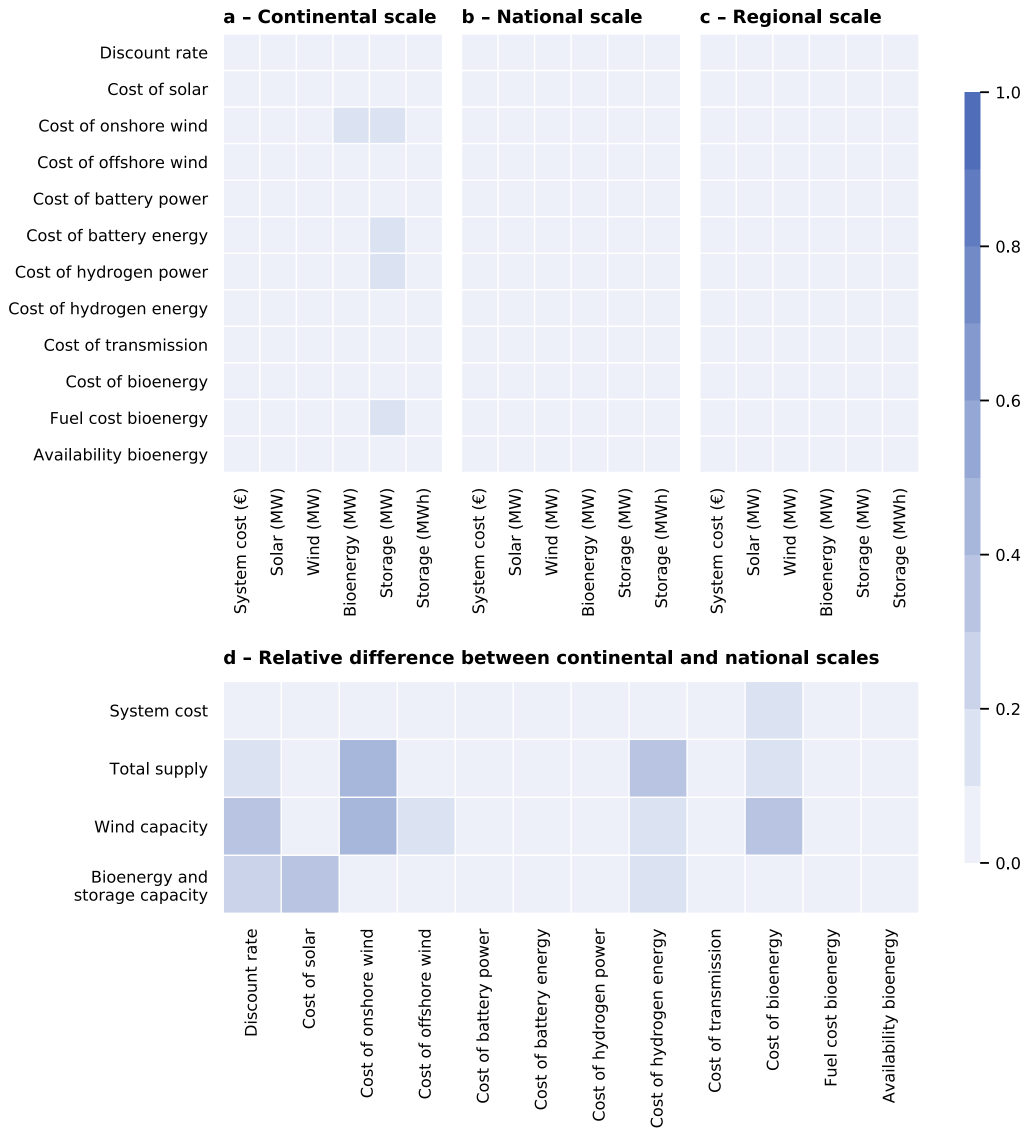

Figure B4: Total minus first-order Sobol' indices for combinations of all considered input uncertainties and selected model outputs of entirely continental-, national-, and regional-scale electricity systems. a,b,c, Sobol' indices of input parameters considering total system cost and total installed capacities (x-axis) of the continental- (**a**), national- (**b**), and regional-scale (**c**) systems. The y-axis shows the twelve input parameters included in the uncertainty analysis. **d,** Sobol' indices of input parameters considering difference in system cost between the continental- and national-scale systems. The x-axis shows the twelve input parameters included in the uncertainty analysis. The y-axis shows the model-wide result variables for which continental to national scale differences are compared.

B9: Transmission network

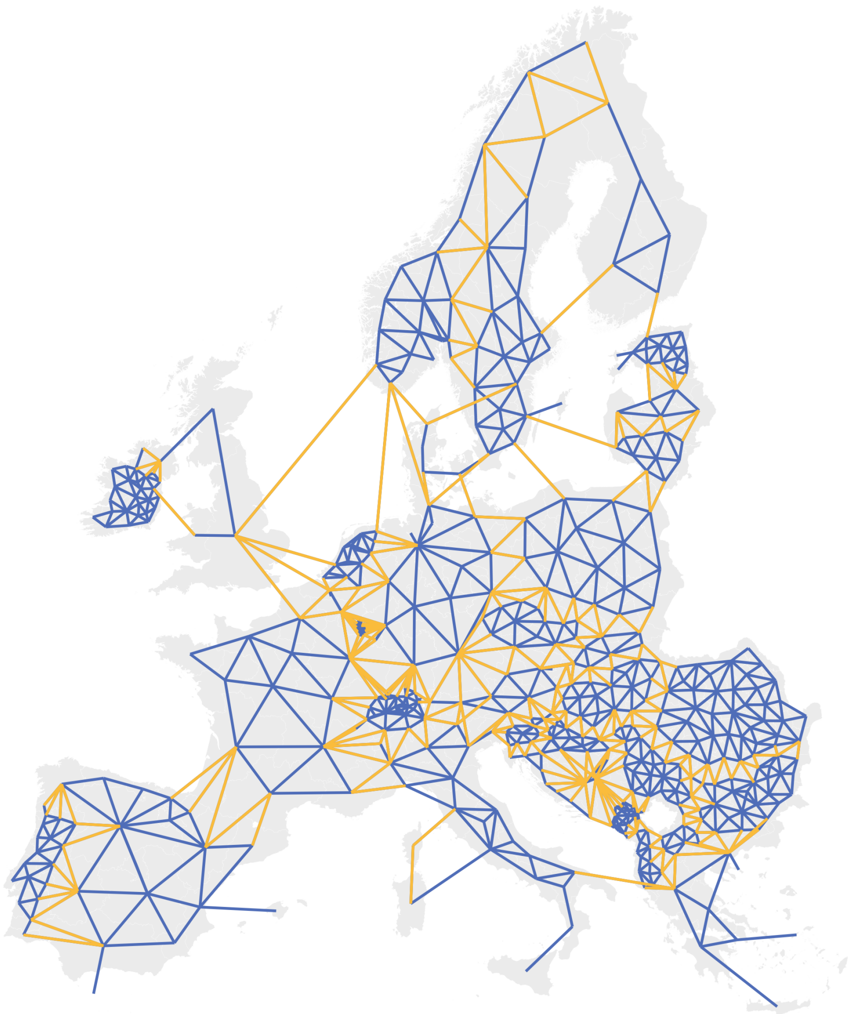

Figure B5: Possible locations of transmission capacities. All lines visualise connections between two regions that can hold transmission capacities. International connections are coloured yellow, all others are coloured blue. The amount of capacities installed on these connections is an output of the optimisation and depends on the considered case.

B10: Distribution of time series across regions

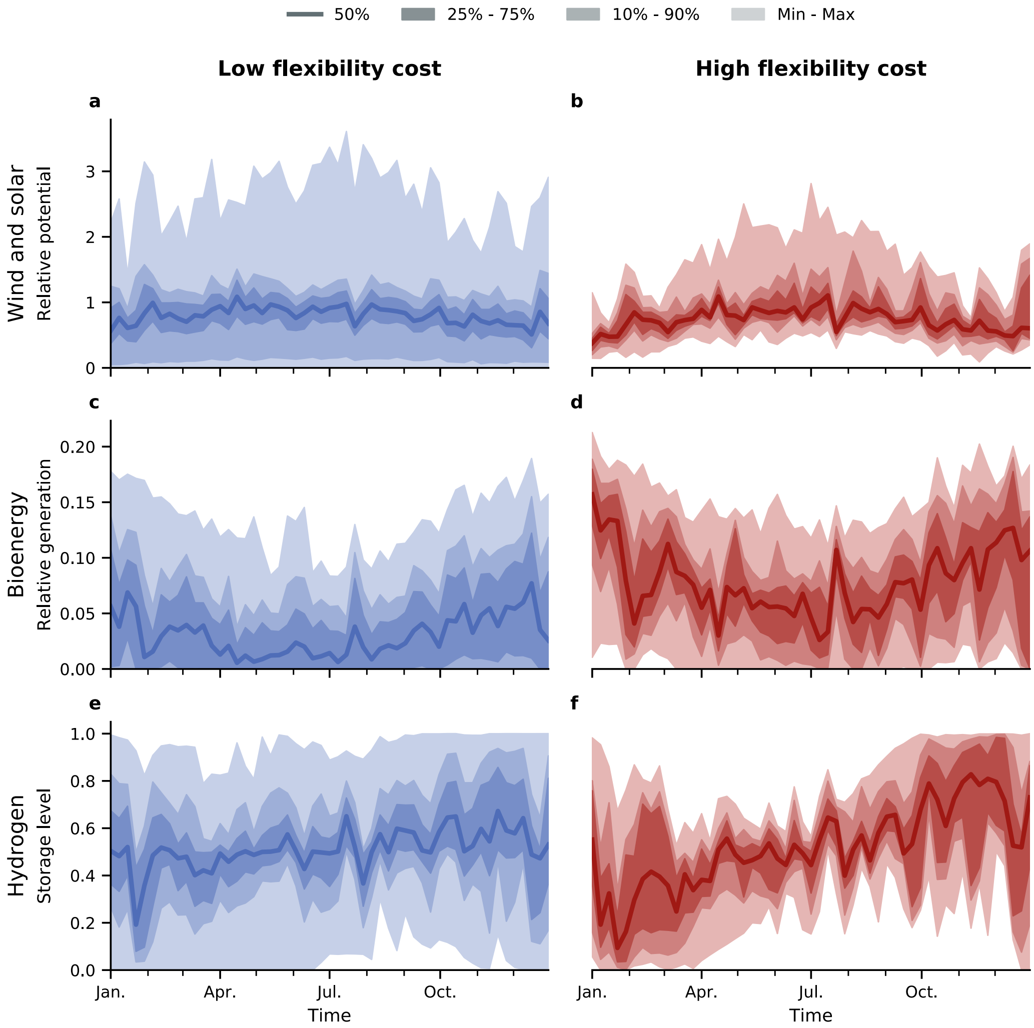

Figure B6: Distribution of time series for all regions of the entirely regional-scale electricity system. **a,b,c,d,e,f,** Distribution of time series for all regions with low flexibility cost (combined cost of bioenergy, hydrogen, and battery storage) (**a,b,c**) and all regions whose flexibility cost lies within the highest decile (**d,e,f**). **a,b,** Combined wind and solar weekly generation potential time series relative to local demand. Seasonal fluctuations are more pronounced for the case with higher cost due to higher shares of solar electricity. Regions with high solar shares are often urban regions with low or no wind potential. **c,d,** Weekly generation time series from biomass combustion relative to demand. Generation has a more pronounced seasonality and is generally larger in regions with higher flexibility cost. **e,f,** Weekly time series of hydrogen storage levels relative to installed storage capacity. In regions with higher cost, hydrogen storage is used primarily to balance seasonal fluctuations, instead of balancing fluctuations within weeks or months as it is done for lower cost regions, leading to fewer storage cycles and higher cost.

B11: Input parameter uncertainty

Table B1: Uncertain input parameters. For all parameters we assume a uniform distribution.

Name	Description	Min	Max	Unit	Source
Discount rate	System- and sector-wide discount rate of investments.	0.016	0.138	-/yr	Max and min for solar and wind between 2009 and 2017 in ref. Steffen (2019)
Cost of solar	Cost of installing photovoltaics capacity.	280	580	EUR/kW	JRC (2014) (Table 7)
Cost of onshore wind	Cost of installing onshore wind capacity.	800	1700	EUR/kW	JRC (2014) (Table 4)
Cost of offshore wind	Cost of installing offshore wind capacity.	1790	3270	EUR/kW	JRC (2014) (Table 5)
Cost of battery power	Cost of installing battery power capacity (inverter etc.).	31	141	EUR/kW	Schmidt et al. (2019)
Cost of battery energy	Cost of installing battery energy capacity.	36	166	EUR/kWh	Schmidt et al. (2019)
Cost of hydrogen power	Cost of installing hydrogen power capacity (fuel cell etc.).	1123	2100	EUR/kW	Schmidt et al. (2019)
Cost of hydrogen energy	Cost of installing hydrogen energy capacity.	6	12	EUR/kWh	Schmidt et al. (2019)
Cost of transmission	Cost of installing net transfer capacity (high voltage ac transmission).	0.7	1.08	EUR/kW/km	JRC (2014) (Table 39)

Name	Description	Min	Max	Unit	Source
Cost of bioenergy	Cost of installing biofuel capacities.	1380	3450	EUR/kW	JRC (2014) (Table 48)
Fuel cost bioenergy	Fuel cost biofuel (includes combustion efficiency and variable generation cost).	0.028	0.034	EUR/kWh	Ruiz Castello et al. (2015)
Availability bioenergy	Interpolation between biofuel potential scenarios.	0.0	1.0	.	Ruiz Castello et al. (2015)

B12: Generation and storage capacities

Table B2: Installed capacities of photovoltaics (PV), on- and offshore wind, bioenergy, short-term (battery) and long-term (hydrogen) storage, and relative curtailment of solar, wind, and hydropower for all considered cases. Each case additionally contains fixed hydropower capacities on their current locations: 36 GW run of river, 103 GW / 97 TWh reservoirs, and 54 GW / 1.3 TWh pumped hydro storage.

Case	PV (GW)	Wind (GW)	Curtailment (%)	Bioenergy (GW)	Battery (GW)	Battery (GWh)	Hydrogen (GW)	Hydrogen (GWh)
Entirely continental case	233	752	6	17	50	201	26	2765
Entirely national case	503	691	8	136	122	486	85	6385
Entirely regional case	724	670	10	187	205	820	96	12121
Continental scale balancing, national scale supply and 0% net imports	286	836	10	38	48	192	25	2280
Continental scale balancing, national scale supply and 15% net imports	263	806	9	37	47	189	22	2090
Continental scale balancing, national scale supply and 30% net imports	237	793	8	32	45	181	22	2240
Continental scale balancing, regional scale supply and 0% net imports	563	886	11	31	71	283	59	5772
Continental scale balancing, regional scale supply and 15% net imports	489	841	10	41	61	245	36	3435

Case	PV (GW)	Wind (GW)	Curtailment (%)	Bioenergy (GW)	Battery (GW)	Battery (GWh)	Hydrogen (GW)	Hydrogen (GWh)
Continental scale balancing, regional scale supply and 30% net imports	424	810	10	45	56	222	22	2121
National scale balancing, regional scale supply and 0% net imports	622	722	8	135	131	502	90	6939
National scale balancing, regional scale supply and 15% net imports	585	700	7	139	120	474	88	6601
National scale balancing, regional scale supply and 30% net imports	557	689	7	142	118	471	84	6210

B13: Transmission capacities

Table B3: Installed transmission grid capacity, gross physical electricity flow crossing country borders, and net electricity flow imported by all countries for all cases.

Case	Transmission (TW km)	National import gross (TWh)	National import net (TWh)
Entirely continental case	384	2989	1441
Entirely national case	101	0	0
Entirely regional case	0	0	0
Continental scale balancing, national scale supply and 0% net imports	262	1643	25
Continental scale balancing, national scale supply and 15% net imports	284	1782	390
Continental scale balancing, national scale supply and 30% net imports	312	2103	751
Continental scale balancing, regional scale supply and 0% net imports	169	1331	49
Continental scale balancing, regional scale supply and 15% net imports	198	1499	352
Continental scale balancing, regional scale supply and 30% net imports	238	1776	659
National scale balancing, regional scale supply and 0% net imports	59	0	0
National scale balancing, regional scale supply and 15% net imports	68	0	0
National scale balancing, regional scale supply and 30% net imports	79	0	0

B14: Biomass feedstocks

Table B4: Biomass feedstocks we consider, together with the proxy we use to derive regional from national values.

Feedstock	Proxy
Manure biomass	Farmland
Primary agricultural residues	Farmland
Roundwood fuelwood	Forests
Roundwood Chips & Pellets	Forests
Forestry energy residue	Forests
Secondary forestry residues – woodchips	Forests
Secondary Forestry residues – sawdust	Forests
Forestry residues from landscape care	Forests
Municipal waste	Population
Sludge	Population
Landscape care residues	Population

B15: Technology cost assumptions

Table B5: Assumptions on technology cost. ^AC transmission overnight cost is given in €/kW/1000km

Technology	Overnight cost (€/kW)	Overnight cost (€/kWh)	Annual cost (€/kW/yr)	Variable cost (€ct/kWh)	Lifetime (yr)	Source
PV	520	0	8	0	25	JRC (2014) Table 7
Onshore wind	1100	0	16	0	25	JRC (2014) Table 4
Offshore wind	2280	0	49	0	30	JRC (2014) Table 5
Biofuel	2300	0	94	6	20	JRC (2014) Table 48, ref. Ruiz Castello et al. (2015)
Hydropower run of river	0	0	169	1	60	JRC (2014) Table 14
Hydropower with reservoir	0	0	101	1	60	JRC (2014) Table 12
Pumped hydro storage	0	0	7	0	55	Schmidt et al. (2019)
Short term storage	86	101	1	0	10	Schmidt et al. (2019)
Long term storage	1612	9	14	0	15	Schmidt et al. (2019)

Techno-logy	Overnight cost (€/kW)	Overnight cost (€/kWh)	Annual cost (€/kW/yr)	Variable cost (€ct/kWh)	Lifetime (yr)	Source
AC trans-mission^	900	0	0	0	60	JRC (2014) Table 39

Appendix C: Supplementary material to contribution III

C1 Code and data

The code and reproducible workflow used to perform this analysis is available online (Tröndle, 2020b). Furthermore, the resulting data is available online as well (Tröndle, 2020c).