Distributional trade-offs between regionally equitable and cost-efficient allocation of renewable electricity generation

Sasse, Jan-Philipp; Trutnevyte, Evelina

How to cite

SASSE, Jan-Philipp, TRUTNEVYTE, Evelina. Distributional trade-offs between regionally equitable and cost-efficient allocation of renewable electricity generation. In: Applied Energy, 2019, vol. 254, p. 113724. doi: 10.1016/j.apenergy.2019.113724

This publication URL: https://archive-ouverte.unige.ch/unige:121756

Publication DOI: 10.1016/j.apenergy.2019.113724

Distributional trade-offs between regionally equitable and cost-efficient allocation of renewable electricity generation

Authors: **Jan-Philipp Sasse[1,2]*, Evelina Trutnevyte[1]**

[1] Renewable Energy Systems, Institute for Environmental Sciences (ISE), Section of Earth and Environmental Sciences, University of Geneva, Switzerland

[2] Institute for Environmental Decisions (IED), Department of Environmental Systems Science, ETH Zurich, Switzerland

* corresponding author (Uni Carl Vogt, Boulevard Carl Vogt 66, CH-1211 Geneva 4, Switzerland; +41 22 379 06 03; jan-philipp.sasse@unige.ch)

Highlights

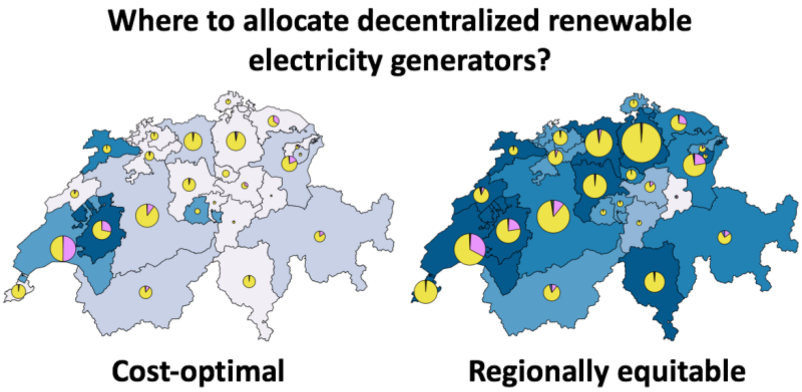
- Distributional impacts assessed for decentralized renewable generation (DREG)
- Large trade-offs found between cost-efficient vs. regionally equitable allocation
- Least-cost allocation implies concentrating DREG to few most productive sites only
- Solar PV is key for more regional equity with small trade-offs in generation costs
- Policies for cost-efficient DREG allocation risk strengthening regional disparities

Abstract

Decentralized renewable electricity generation (DREG) has been growing at an unprecedented pace, yet the appropriate spatial allocation and associated regional equity implications remain underinvestigated. In this study, we quantify the trade-offs between cost-efficient (least-cost) and regionally equitable DREG allocation in terms of electricity generation costs, investment needs, and DREG capacity requirements. Using the case of the ambitious and publicly-approved Swiss Energy Strategy 2050, we set up a bottom-up, technology-rich electricity system model EXPANSE with Modeling to Generate Alternatives at a spatial resolution of 2'258 Swiss municipalities. In order to measure regional equity implication, we adapt the concepts of the Lorenz curve and the Gini coefficient. We find a significant trade-off by 2035 in Switzerland: 50% increase in regional equity when allocating DREG to various Swiss regions on the basis of population or electricity demand leads to 18% higher electricity generation costs. Least-cost allocation implies concentrating DREG and associated

investments to few most productive locations only. Solar PV is the key technology for increasing regional equity. We conclude that in countries with spatially-uneven DREG resources like Switzerland, any policies that focus on cost efficiency should anticipate regional equity implications in advance and, if desired, minimize them by promoting solar PV.

Graphical Abstract



Keywords

Decentralized renewable electricity generation, spatial modeling, regional equity, solar PV, distributional impacts, energy justice

1. Introduction

The last decade was characterized by the largest ever increase in installed capacity of decentralized renewable electricity generation (DREG, i.e., solar PV, wind, biomass, and small hydropower) as well as by falling costs [1]. Installed solar PV capacity grew globally about fiftyfold, followed by wind energy that rose nearly sixfold [2]. Growth of solar PV was mostly driven by substantial reductions in technology cost, where PV module prices decreased by 81% since the end of 2009 [1], as well as a result of generous policy incentives in some countries. The increased deployment of DREG is foreseen to continue in the future, and it is very much needed in order to reduce greenhouse gas emissions and local pollution, contribute to national energy security and economic growth, create jobs, and provide affordable and reliable energy for all [1]. As in every transition, however, there is a risk that some regions are more able than others to build DREG [3,4]. Low-carbon transition that is based on DREG thus risks generating new patterns of spatially uneven regional development, such as the clustering of DREG investments, jobs, or policy support to few locations [5]. Finding ways to address regional distributional impacts and to anticipate potentially emerging inequities is a new and recently noticed policy challenge [6].

In the global context, Switzerland plays a pioneering role with its ambitious Energy Strategy 2050 that, for the first time worldwide, has been approved in a national referendum in 2017 by 58% of the Swiss voters [7]. In the electricity sector, the Energy Strategy 2050 sets a centrally-coordinated framework to support DREG and efficiency improvements in order to replace five existing nuclear reactors that currently constitute 32% of the electricity mix [8]. The non-hydro DREG (i.e., solar PV, wind, biomass, and enhanced geothermal systems) therefore need to grow from 2.5 TWh/year in 2017 to 11.4 TWh/year in 2035 [9] and they are incentivized by one-time subsidies or feed-in-tariffs. The early evidence shows that DREG was adopted regionally unevenly so far [10], but little is known to what extent the emerging spatial pattern can have unintended consequences in terms of DREG generation costs or regional equity implications.

Cost-efficient and regionally equitable spatial deployment of DREG can both have positive and negative implications on the cost, social acceptance and system-wide output variability of DREG. From an investor "component-level" perspective, a cost-efficient DREG allocation is desirable as it maximizes electricity generation at minimum electricity generation costs [11]. However, such an allocation strategy could be problematic for society, as it encourages a clustering of DREG to only few locations with the best harvesting conditions [12]. In addition, there is a broader realization that component-level efficiency does not necessarily coincide with whole-system efficiency [11–13]. Studies have shown that more even distributions of intermittent wind and solar installations can be more cost-efficient, if transmission and storage costs are included [12,14,15].

From a policy perspective, spatially-even DREG allocations could be more desirable, as an unequal regional distribution of investments, policy support, or other economic benefits could raise public concerns [16] and increase policy implementation risk [17]. With rapidly rising numbers of DREG, there is an increased risk of public aversion, which can be provoked by human disturbances caused by wind turbines [18], solar panels [19], or enhanced geothermal systems (EGS) [20]. In order to ensure a just transition with low implementation risks, a more holistic approach is required that considers social equity and acceptability of new DREG installations. Distributional justice of energy infrastructure represents a call for a more equitable distribution of benefits and burdens on all members of society regardless of income, race and other factors [21]. From a sub-national perspective, regional equity is also desirable for enabling a renewable transition with maximum attention to local needs [17].

Apart from potentially higher public acceptance [22], reduced policy implementation risk [17], and a more even distribution of benefits and burdens of energy developments, regional equity also has advantages from a technical standpoint too. Electricity that is supplied close to demand reduces the need for complex and extensive new transmission lines [14,15]. In addition, regional equity can support the balancing of decentralized and naturally volatile DREG electricity supply [23]. Spatially disaggregating weather-dependent DREG across different regions can counterbalance spatially- and temporally-correlated weather patterns [24–26]. Regional equity can therefore make power systems with high shares of DREG more resilient. In practice, however, the allocation of DREG is less a question of optimal spatial allocation and more dependent on local planning, political decisions and policy choices [11]. In the case of solar PV, for example, exploitable solar PV potential, regional spillover effects, economic resources, home ownership and population density [10,27–29] were found to be the key predictors of regional PV penetration.

Several studies so far assessed the implications of various spatial allocation strategies for DREG. Using spatially-explicit electricity sector modeling, most studies investigated the least-cost DREG allocations [30,31], focused on the implications of weather effects on DREG siting [23,32], or quantified the regional economic impacts of several existing DREG scenarios [4]. More recently, new electricity system models which directly incorporate energy justice principles have been developed to propose more equitable energy developments – for example regarding the equitable distribution of energy infrastructure in Germany [12] or regarding the equal access of electricity in sub-Saharan Africa [33]. In the former example, Drechsler and colleagues [12] developed a spatially-explicit model for Germany in order to, for the first time, assess the trade-off between regionally equitable and cost-efficient allocation of wind turbines and open-field solar PV. The study found a weak and hence thought-provoking tradeoff: there is only 2% difference in total generation costs between cost-efficient and regionally equitable allocation of these plants in Germany. Significant increases in regional equity can be achieved with very small increases in costs, when not all wind turbines are located in the windy North of Germany and not all solar panels in the sunnier South. While providing an essential first step of quantifying the trade-off, this study only analyzed wind and solar PV and neglected the rest of the electricity generation mix with centralized and decentralized generators. The study also focused on the case of Germany with relatively evenly distributed solar and wind resources and it is unclear whether the same conclusions of negligible trade-off would apply elsewhere.

What is lacking in the current scarce scientific evidence is a more nuanced understanding of the trade-offs between regionally equitable and cost-efficient (least-cost) allocation strategies for the rapidly growing DREG. First, especially in countries like Switzerland with spatially uneven renewable energy resources, the trade-offs can be expected not to be negligible. Second, in-depth assessments of the actual spatial patterns in DREG growth are necessary [11] in order to identify whether DREG transition is on a path to deepen regional disparities or to deviate from cost-efficient futures.

In this study, we explore the issue of where to appropriately allocate DREG in Switzerland by combining spatially-explicit electricity sector modelling with energy justice theory. Specifically, we focus on assessing the distributional trade-offs of DREG allocation in terms of cost-efficient and regionally equitable justice principles. In Section 2, we briefly introduce the key concepts of energy justice theory and propose an overall framework of distributional energy justice, in which we embed our analysis. Then, we set up a bottom-up, technology-rich electricity system model EXPANSE with Modeling to Generate Alternatives at a spatial resolution of 2’258 Swiss municipalities. Using this model, we quantify the trade-offs between cost-efficient (least-cost) and regionally equitable DREG in Switzerland in terms of electricity generation costs, investment needs, and DREG capacity requirements.

2. Overall framework of distributional energy justice

Energy justice has emerged as a new interdisciplinary research field which seeks to apply justice principles to energy policy, energy production, energy consumption, energy activism, energy security, and climate change [21]. In order to explore existing energy challenges through the lens of social justice theory, a range of conceptual frameworks has emerged. Jenkins et al. [21] propose a framework with three considerations of justice: to identify the distributional benefits and burdens of energy developments (distributional justice), to identify who they affect (recognition-based justice), and to identify strategies for remediation (procedural justice). Sovacool et al. [34] explore a wide range of energy justice issues such as energy-related human rights abuses, energy poverty and negative externalities across several dimensions, including time, economics, politics, geography, and technology. In an attempt to qualitatively evaluate the impact of replacing coal-fired power plants with wind turbines and solar panels, Chapman et al. [35] introduce an equity factor framework which enhances the standard cost mitigation approach by additionally considering equitable outcomes for society in terms of regional greenhouse gas reduction, health, employment and electricity prices.

We adapt the above-mentioned concepts to derive an own overall framework of distributional energy justice (Fig. 1). The proposed framework is an effort to conceptualize and measure the distributional impacts of DREG allocation. We include three energy justice types: distributional, procedural and recognition justice [21]. Our framework focuses in detail on distributional justice, for which we further distinguish between three dimensions: across time, society, and space. Distributional justice across time relates to intergenerational justice and injustice, such as environmental externalities caused by the energy system (e.g. impacts and mitigation of climate change, resource depletion, or nuclear waste). The societal dimension reflects justice and injustice, such as the unequal impact of energy on low- vs. high-income households or social marginalization of certain groups of society. The third dimension across time examines justice and injustice, such as regionally uneven environmental and economic developments. Within the spatial dimension, we distinguish between the main categories of equity factors: energy technology, economic costs and benefits, energy access and security, environmental impacts, health impacts and impacts on employment and income.

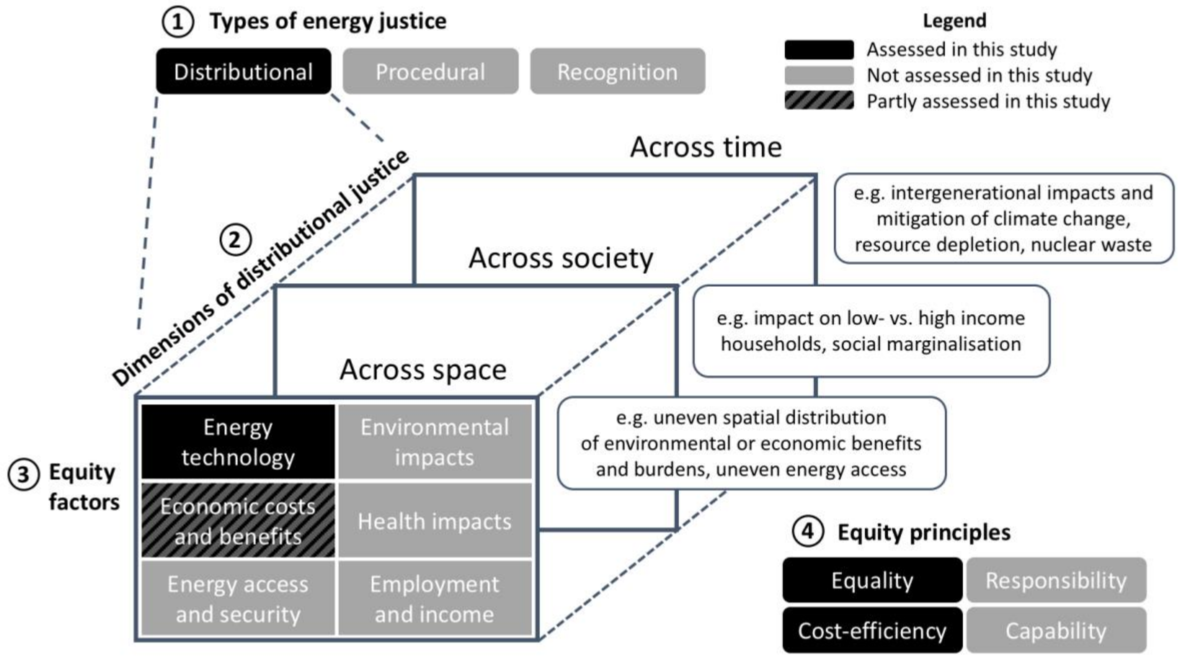


Figure 1. Energy justice framework including energy justice types (1) and dimensions (2), equity factors (3), and equity principles (4)

We include four equity principles for distributional justice as proposed by Höhne et. al. [36]: equality, cost-efficiency, capability, and responsibility. Equality (e.g. regional equity) relates to the egalitarian principle, which translates into the equal allocation of benefits and burdens across all members of society, space or time [37]. In contrast, the cost-efficiency principle relates to utilitarianism which aims to maximize the total sum of utilities of society [38,39]. The capability principle is often referred to as "capacity" or "ability to pay for mitigation" [36]. Under this principle, it is equitable if more capable regions (e.g. regions with higher gross domestic product) have, for example, more ambitious DREG adoption targets. The responsibility principle states that it is equitable if regions with, for instance, higher historical contribution to global emissions do more than others [36].

This paper attempts to enrich traditional electricity sector modelling by directly incorporating some of the before mentioned concepts of energy justice. In our model, we assess the trade-off between cost-efficient and regionally equitable allocation of DREG in terms of electricity generation cost, DREG installed capacity and capital investments. The equity indicators that are relevant for this study are shaded in black in Fig. 1. In Section 3, we briefly introduce our model, the required data and our methodological approach are described.

3. Methods

3.1 EXPANSE electricity system model

In this study, we use a spatially-explicit, bottom-up, technology-rich, perfect-foresight electricity system model called EXPANSE (EXploration of PAtterns in Near-optimal energy ScEnarios) [40–42]. The detailed documentation of the model can be found in the Supplementary Information. We apply EXPANSE to assess a total of 2’000 spatial DREG allocation scenarios in all 2’258 Swiss municipalities for the year 2035. In order to computationally accommodate the high spatial resolution and high number of scenarios of our model, we analyze annual demand and supply sums only. Yet, we also ensure that maximum amounts of DREG integration do not exceed the technical limits from Swiss studies with higher temporal resolution [15].

As a bottom-up model, EXPANSE relies on the linear optimization of total electricity generation costs at a municipal level with national-level constraints. In this way, EXPANSE puts municipal decisions on DREG siting at the core rather than assumes a federal-level central planner as other bottom-up models [43]. EXPANSE includes spatially-refined data on the Swiss electricity demand and generation for the key centralized technologies (large hydropower dams, large run-of-river hydropower, and gas power plants), DREG technologies (small hydropower, solar PV, wind turbines, EGS, woody biomass, biogas, and waste incineration), net import, and electricity savings through end-use efficiency measures (see Supplementary Information). We do not consider open-field solar PV in our model, as these are almost non-existent in Switzerland and are unlikely in the future due to social concerns over land use [44].

By applying state-of-the-art Modeling to Generate Alternatives (MGA) method [40,41,45], EXPANSE does not only investigate cost-efficient (least-cost) scenarios of DREG allocation but also computes 2’000 so-called near-optimal scenarios that have up to 20% higher total electricity generation costs. In this way, the trade-off between regional equity and cost-efficiency can be quantified for a very large number of scenarios that are still at reasonable costs. Regarding the predefined value of slack, existing modeling studies typically assume 10-30% [42,43,46,47]. For the study reported here, a maximum slack of 20% is assumed because the aim is any way to illustrate the gradient in terms of increasing total system costs and regional equity.

3.2 Regional equity quantification

In accordance with the equality principle described in Section 2, we define regional equity as the spatially even distribution of DREG electricity generation. Specifically, two regional equity indicators are calculated: even DREG allocation on the basis of population size or on the basis of electricity demand of each municipality. In our definition, it is perfectly regionally equitable (Equity=100%) if every municipality produces the same amount of DREG electricity per capita or per kWh of demand, and it is perfectly regionally inequitable (Equity=0%) if all DREG electricity is generated by only one municipality.

We measure the regional equity performance of each spatial allocation scenario by using an adapted Gini index, which is similar to the method described by Drechsler et al. [12]. The Gini index is a common statistical indicator for measuring the uniformity within a given distribution [48]. The graphical representation of this adapted Gini index is the Lorenz curve (Fig. 1), which shows the proportion of total DREG electricity that is generated by the cumulative municipal population share or electricity demand share. The equity index of 0% to 100% is equal to 100% minus the ratio of the area that lies between the perfect equity line and the Lorenz curve (marked as A in Fig. 1) over the total area under the perfect equity line (marked as A and B): Equity = 100% – A / (A + B).

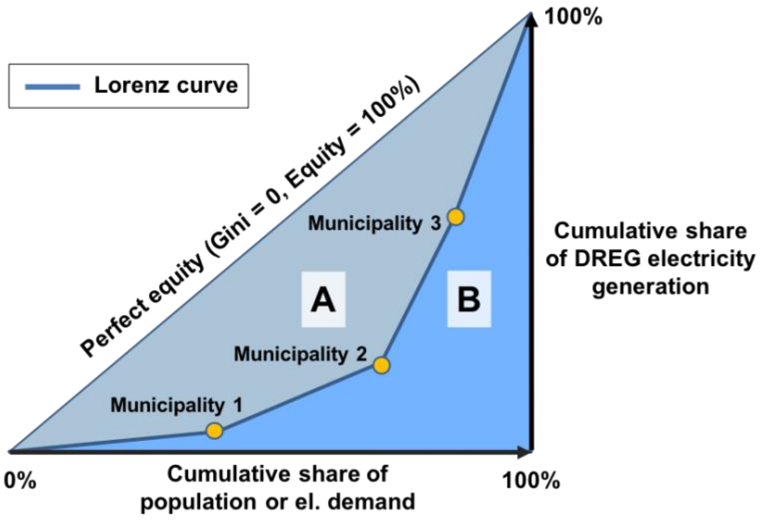


Figure 2: Graphical representation of the adapted Gini coefficient (Lorenz curve).

In contrast to the proposed method by Drechsler et al. [12], we assess the Gini index not only for solar PV and wind, but for a wider range of DREG by including biomass, EGS and small hydro generators. In addition, we do not normalize DREG electricity generation by its technical potential. Doing so would alleviate the cost-equity trade-off, as the technical potential and levelized cost of electricity are negatively correlated.

3.3 Defining the least-cost, maximum equity, and current trend scenarios

The least-cost scenario is defined as the spatial allocation scenario with the lowest total electricity generation costs and it is the first output of the optimization model EXPANSE. The optimization occurs for each municipality individually and the municipal outputs are aggregated to the national level. The maximum regional equity is defined as the scenario with the highest regional equity score (proportional to population or electricity demand) within the set of 2’000 near-optimal spatial allocation scenarios. The current trend scenario is a synthetic scenario that represents the continuation of the current trends of financially-supported DREG diffusion in Switzerland and it is constructed by applying two methods. With the first method, we extrapolate the electricity generation from woody biomass and biogas systems by applying a linear extrapolation of the latest 5-year trend (2013 – 2017) [49]. For all other DREG, we adopt the “business-as-usual” projection for 2035 from [50,51] and apply the regional proportions of the current spatial allocation. The electricity generation in each municipality will increase (or decrease) to a predicted value [50,51], mainly due to efficiency increases or due to additional installations (e.g., more solar PV panels or wind turbines). In each municipality, the maximum electricity that can be generated by each DREG remains bounded by technical, environmental, and legal limits.

3.4 Scenario modelling approach

Initially, we determine the least-cost (cost-efficient) spatial allocation of DREG on a municipal level, so that the Energy Strategy 2050 target of 11.4 TWh electricity from non-hydro DREG is reached at minimum total electricity generation cost. Next, we explore near-optimal spatial allocation scenarios by allowing electricity generation costs to be up to 20% higher than the electricity generation costs in the least-cost scenario. Using the generated set of least-cost and near-optimal spatial allocation scenarios, we finally explore the trade-offs in terms of electricity generation cost, capital investment needs, DREG capacity, and regional equity. From the 2’000 national scenarios, we also select four distinct scenarios for in-depth analysis: the least-cost scenario, two scenarios with the highest regional equity scores per person and per kWh, and the current trend scenario. For each of these four scenarios, we again analyze their total electricity generation costs, required DREG investments and capacity, and regional equity outcomes per person and per kWh.

4. Results and discussion

4.1 Trade-offs between electricity generation costs and regional equity

We find a substantial trade-off between cost-efficient (least-cost) and regionally equitable DREG allocation strategies in Switzerland (Fig. 3). The least-cost scenario is the least regionally equitable scenario, and the most regionally equitable scenarios have the highest electricity generation costs. In the least-cost scenario for 2035, where total electricity generation costs are minimized for each Swiss municipality, the total electricity generation costs for Switzerland as a whole, including DREG, centralized generation, and electricity import, are 8.54 Rp./kWh (100 Rp.≈100 US cents). The Gini-coefficient's values for regional equity are 28.6% (weighted by population) and 28.3% (weighted by electricity demand). In the most regionally equitable scenarios by population and by electricity demand, the total electricity generation costs are up to 18% higher and equal to 10.10 Rp./kWh and 10.04 Rp./kWh, respectively. The regional equity outcomes are 43.1% by population and 43.0% by demand. By comparing the least-cost and maximum equity scenarios, we find that an increase in regional equity per population by 50% from the least-cost scenario leads to an increase in electricity generation costs of 18% (+1.56 Rp./kWh). Our results suggest that at least in Switzerland, where DREG resources are not evenly distributed throughout the country, the sole focus on the cost efficiency principle in siting DREG means that DREG installations will be spatially concentrated to fewer locations. The strategy of a regionally equitable DREG distribution comes with a significant negative impact on electricity generation costs. When examining the current trend scenario, we find that it deviates from this Pareto frontier of equity-costs trade-off in terms of both, electricity generation cost and regional equity (Fig. 3). This finding, therefore, indicates that there is space for improvement in Switzerland, either in terms of lowering generation costs or improving regional equity when allocating DREG.

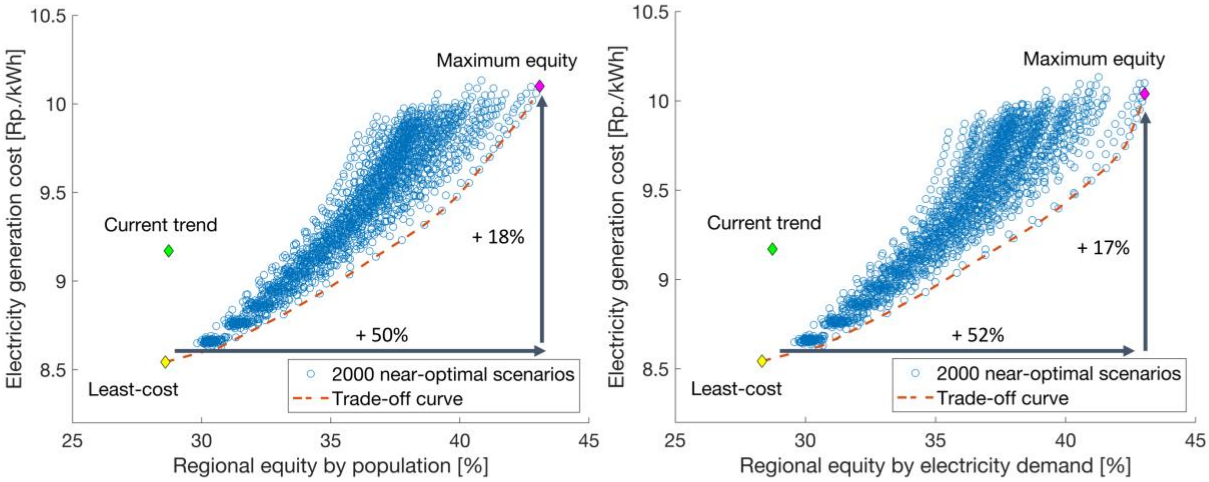


Figure 3: Trade-off between regional equity and total electricity generation cost for 2’000 spatial scenarios of DREG allocation in Switzerland in 2035. Note: 100 Rp.≈100 US cents

4.2 DREG share in the electricity generation mix and spatial DREG distribution

We further analyze the share and composition of DREG in the electricity generation mix for the four selected scenarios: least-cost, current-trend, and maximum regional equity by population and by electricity demand (Fig. 4). In all scenarios, solar PV is the most dominant DREG technology due to the expected decrease in its costs by 2035. With increasing regional equity, DREG increases, and we especially find an increasing share of electricity generated by solar PV (8% in the least-cost scenario vs. 20% in the maximum equity scenarios). This result suggests that solar PV is the key technology in Switzerland for achieving as regionally equitable transition as possible at reasonable costs. The reason is that PV panels are far less technically and economically confined to particular regions in contrast to biomass, wind, small hydro or EGS. In the case of Switzerland, they can be deployed in any inhabited area and hence follow the same pattern as our regional equity indicators by population or by electricity demand (open-field PV is not considered in the Energy Strategy 2050). In fact, we find that both of the maximum regional equity scenarios do not differ considerably in terms of the share and composition of DREG and non-hydro DREG can generate up to 19.9 TWh of electricity per year as compared to 11.4 TWh in the least-cost scenario. This result indicates that regionally equitable scenarios with up to 20% higher total costs than in the least-cost case can even exceed the Energy Strategy 2050 target of 11.4 TWh of non-hydro DREG electricity by 75%.

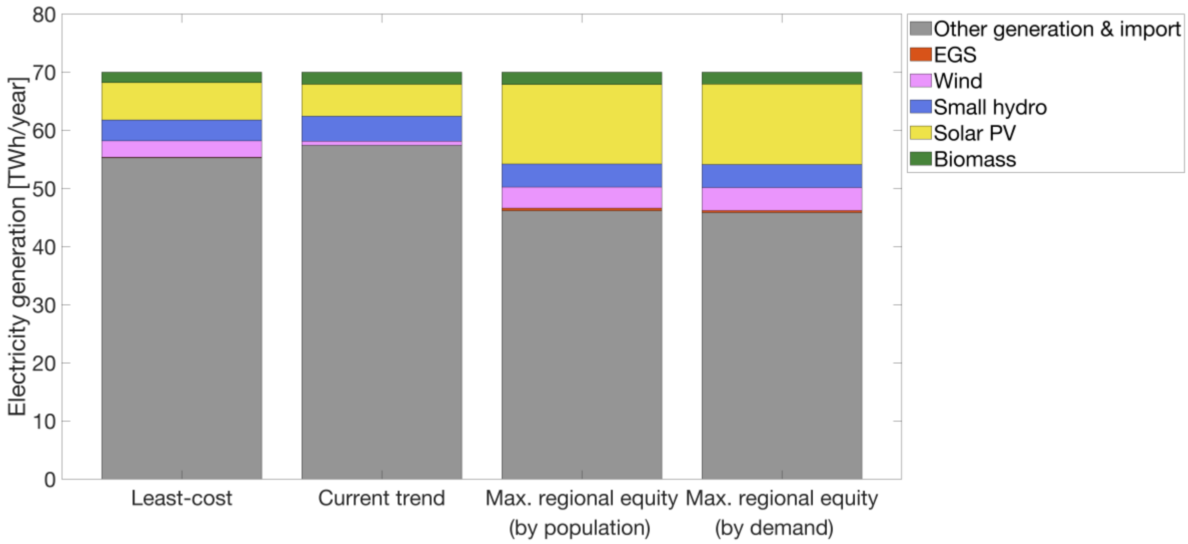


Figure 4. DREG share in the total electricity generation mix in 2035

Fig. 5 shows the spatial distribution of the cumulative installed capacity of DREG in Switzerland from 2016 to 2035 in all four scenarios. In the least-cost scenario, up to 500MW of installed wind capacity is concentrated in the canton of Vaud (Fig. 5a), where there are relatively strong winds and relatively low legislative land constraints for wind turbine installations. In our analysis, wind turbines in canton of Vaud can competitively generate up to 1.37 TWh of electricity per year. With increasing regional equity, mostly solar PV is installed evenly per capita or per consumed kWh across all the Swiss cantons due to comparatively low variations in PV costs, solar irradiation, and available rooftop area. Regionally equitable scenarios weighted by population see a stronger uptake of solar PV in highly populated urban cantons of Zurich and Geneva (Fig. 5c). If regional equity is weighted by electricity demand instead (Fig. 5d), a more substantial uptake in solar PV is required in highly industrialized cantons such as Basel-City (+500MW) and Vaud (+400MW), while less is required in Zurich (-200MW) and Geneva (-400MW). In the current trend scenario, most additional DREG capacity is allocated to more rural areas in the Northeast of German-speaking Switzerland (Fig. 5b). This is neither fully in line with cost efficiency nor with regional equity allocation principles because new DREG is built in locations with relatively lower population, lower electricity demand, lower electricity generation potential, and higher electricity generation costs.

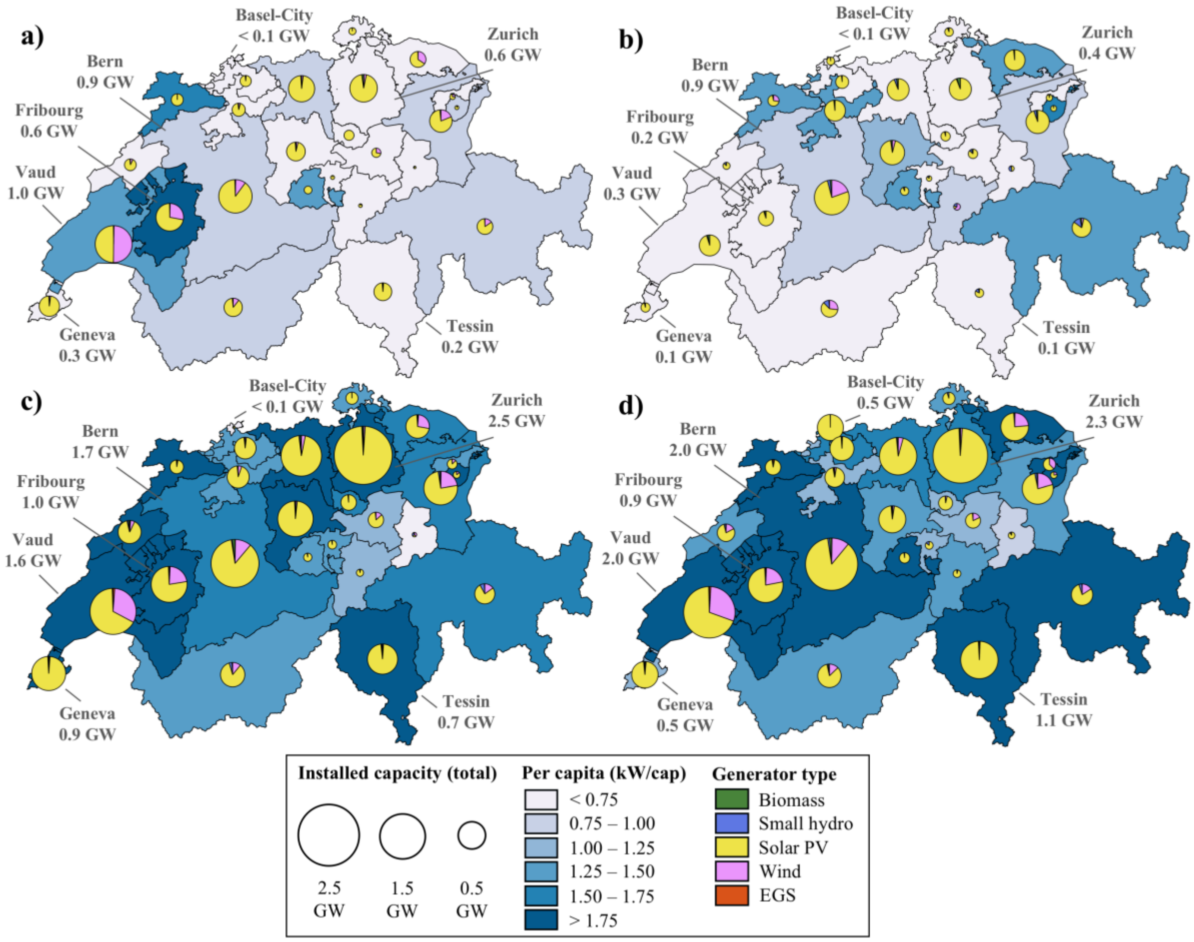


Figure 5. Cantonal distribution of cumulative DREG installed capacity in 2016-2035 for: a) the least-cost scenario, b) current trend scenario, c) maximum regional equity scenario by population and d) maximum regional equity scenario by electricity demand.

4.3 Spatial distribution of DREG investments and regional equity

Fig. 6 shows the cantonal distribution of cumulative capital investments that are needed for DREG in Switzerland in 2016-2035 in the four scenarios. In the least-cost case (Fig. 6a) the total required investment for DREG is CHF 10.0bn (1 CHF ≈ 1 USD). The largest share is allocated in the canton of Vaud (CHF 1.7bn = 17% of the total investment in the country) due to the need to install wind turbines in this region. In order to achieve maximum regional equity, total investment needs for DREG increase considerably to CHF 24.5bn (Fig. 6c) and CHF 24.6bn (Fig. 6d). Such a substantial increase occurs because DREG is investment-intensive as compared to the centralized generation or electricity import (Fig. 4). If regional equity is weighted by population (Fig. 6c), more investments should be allocated to highly populated cantons of Zurich (17%, CHF 4.1bn) and Geneva (6%, CHF 1.4bn). If regional equity is weighted by electricity demand (Fig. 6d), higher shares of investment should go to more industrialized cantons such as Vaud (13%, CHF 3.3bn), Tessin (7%, CHF1.7bn), and Basel-City (3%, CHF 0.8bn). The current trend scenario (Fig. 6b) sees similar total investment needs as in the least-cost case (CHF 8.8bn in total), but with a very different spatial allocation pattern. This is especially notable in the canton of Vaud, where only 7% of total DREG investments are located (CHF 0.6bn). In this case, the highest share of investments is dedicated to the canton of Bern (18%, CHF 1.6bn).

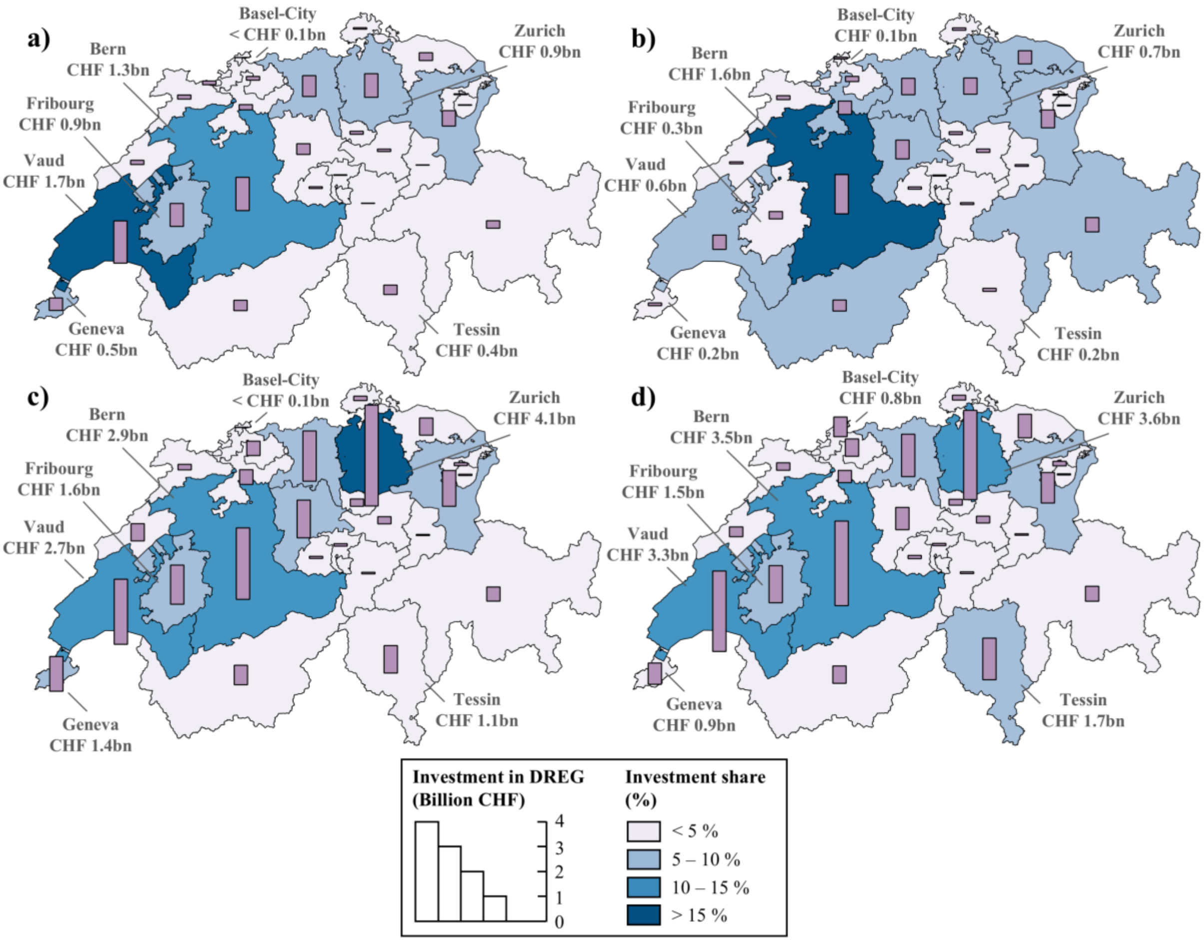


Figure 6. Cantonal distribution of cumulative DREG investment needs in 2016 – 2035: a) the least-cost scenario (CHF 10.0bn in total), b) current trend scenario (CHF 8.8bn), c) maximum regional equity scenario by population (CHF 24.5bn) and d) maximum regional equity by el. demand (CHF 24.6bn). Note: 1 CHF ≈ 1 USD.

Fig. 7 depicts the trade-off curve between regional equity and required DREG investments until 2035 for all 2’000 spatial allocation scenarios. We again find a significant trade-off: in the least-cost case, the DREG investment needs amount to CHF 10.0bn and regional equity is 28.3%. In the maximum regional equity case, the DREG investments amount to CHF 24.5bn (weighted by population) and CHF 24.6bn (weighted by demand), whereas regional equity is

43.1% and 43.0%, respectively. Comparing the least-cost and maximum regional equity scenarios, we find that an increase of 50% in regional equity per population requires 145% higher investments (CHF 14.5bn). In comparison, the DREG investment in the current trend scenario is CHF 8.8bn with a regional equity score of 28.7% by population and by demand. Therefore, the current allocation trend is just slightly more regionally equitable (+1.3%) than the least-cost spatial allocation of DREG, but it is still one of the least regionally equitable scenarios in our scenario set. This current-trend scenario also has the lowest additional DREG investments of all scenarios. But unlike all other scenarios, it does not achieve the Energy Strategy 2050 target of 11.4 TWh non-hydro DREG per year and hence it needs 12% lower investment than in the least-cost scenario. This finding suggests that the current DREG investments could be in the future allocated either in a more cost-efficient way with similar regional equity outcomes or in a way that also improves regional equity.

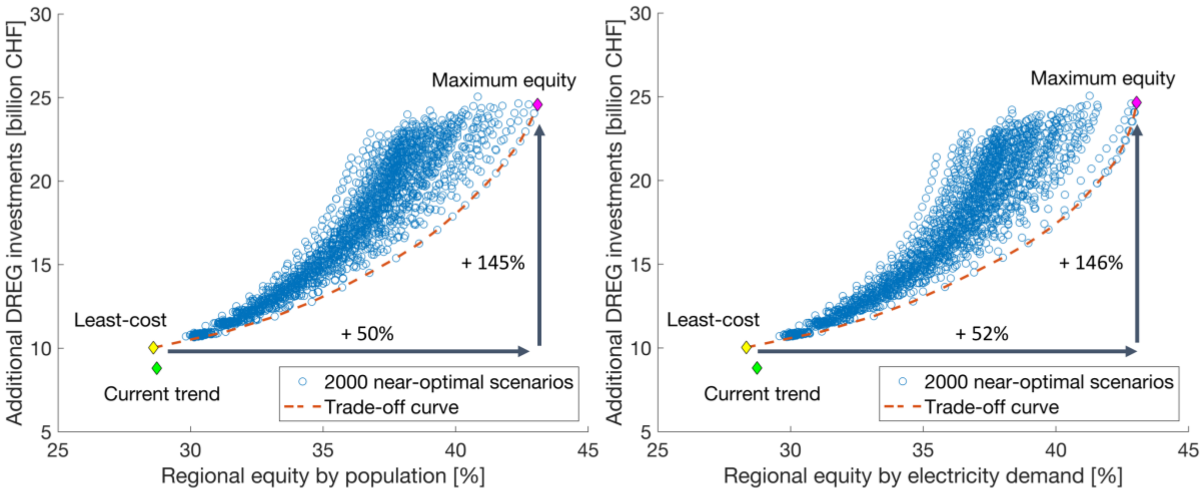


Figure 7: Trade-off between regional equity and required DREG investments in 2016 – 2035 for 2’000 scenarios of spatial DREG allocation in Switzerland. Note: 1 CHF ≈ 1 USD.

4.4. Limitations and future research needs

With the methods shown in this work, we were able to quantify the trade-offs of regionally equitable and least-cost distributions of DREG systems regarding electricity generation cost, capacity requirements and investment needs. Despite the valuable and first-of-the-kind insights gained, some limitations may impact the outcome of our results. First, our model optimizes for each municipality individually which does not happen in reality. Instead, electricity is managed by utilities on a regional level (with multiple municipalities) and by a transmission system operator (TSO) on a national level. Therefore, in the future, it would be more realistic to aggregate the individual municipalities in utility service zones or to apply a national-level optimization. Second, at this stage, we do not include the transmission and distribution (T&D) grid and we do not model the required grid and storage expansion costs. Our study, therefore, for the first time quantifies only the impacts of regional equity on electricity generation, whereas these considerations on T&D and storage should be included in the future versions of the model. On the one hand, this has already been modelled in a different study on Switzerland [15], which found that the overall net economic benefits for the whole electricity system (such as from reduced electricity and fuel imports) outweigh the storage and grid expansion costs, and that these expansions are economically and technically feasible even for scenarios with high amounts of wind and solar electricity. Regarding the spatial allocation of DREG, Drechsler and colleagues [12] show, that the inclusion of the transmission grid would encourage a more equitable allocation of DREG installations to areas with high population and high electricity demand. Third, due to constraints of computing time, we did not consider the volatility of electricity demand and generation and considered only annual sums, but we checked that all of the EXPANSE scenarios would be feasible in light of other existing studies with higher temporal resolution.

Lastly, the trade-off concerning regional equity largely depends on how the equity is defined. As indicated in the proposed distributional energy justice framework (Fig. 1), our quantitative modelling and equity trade-off analysis are by no means exhaustive, as we focus only on few equity indicators. Further research should follow this framework and thus expand the assessment to other distributional impacts, such as on energy poverty, income inequality, job creation, greenhouse gas reductions, or health impacts. Nevertheless, we show that by assessing trade-offs between cost-efficient and regionally equitable DREG allocation in terms of generation cost, capacity requirements and investment needs, researchers can already add significant contextual relevance for policy makers and widen the understanding of distributional impacts.

5. Conclusions

The rapid transition from centralized electricity generation to DREG will inevitably change the spatial fingerprint of the electricity sector and it could lead to land use conflicts, public acceptance issues, and new regional disparities. In theory, any form of transformation should benefit society as a whole and all its regions, not just where it is most cost-effective or convenient. While most electricity sector models rely on cost-effective allocation of DREG, researchers have indicated the need for a broader recognition of equitable distributional impacts arising from DREG diffusion [11,12,34]. In this study, we briefly introduced an energy justice framework that could guide quantitative analysis. In terms of regional distributional trade-offs of DREG allocation, we find that in countries like Switzerland, where the energy resources can vary quite significantly from location to location, there is a significant and direct trade-off between regional equity in DREG allocation and total electricity generation costs. The higher generation costs are acceptable – the more regionally equitable DREG transition can be ensured. If the aim is to keep electricity generation costs as low as possible, then electricity generation needs to be concentrated in the most productive locations only. The technology with relatively low trade-off is solar PV due to its expected significant decreases in costs as well as the relatively low regional variation in electricity generation potential and investment costs. There is no surprise that solar PV is often researched in social scientific literature on inclusive and just transition.

We find that the policy focus on cost efficiency would lead to large concentrations of DREG to few locations in Switzerland and hence would encourage an uneven regional distribution. Currently, the federal economic incentives in the form of feed-in tariffs and one-time subsidies risk fortifying the observed regional disparities but may eventually keep the energy transition closer to the least-cost path. However, the current trend is that the actual transition deviates from both, least-cost and regionally-equitable paths (Fig. 3). Current economic incentives typically do not include mechanisms to additionally incentivize regionally equitable DREG diffusion, if DREG would not always perform at its best in terms of generation costs. Whether policy adjustments are needed and how much weight should be given to regional equity versus generation costs are ultimately the questions of values, as our trade-off curves show (Fig. 3). In any case, due to the rapid growth of DREG and the fact that DREG systems are difficult to reallocate once they are built, now is the right time to reflect on the appropriate spatial DREG allocation and the incentive mechanisms.

Even with its scarce and uneven energy resources, Switzerland has a realistic chance to reach its Energy Strategy 2050 target and cover 20% of its electricity demand with DREG by 2035 in both cases: focusing on cost efficiency or focusing on regional equity. In fact, a regionally equitable strategy would lead to a higher adoption of DREG of up to 33% of total electricity demand. Up to 20% of total electricity demand could be supplied by cost-effective solar PV. This would be a win for the sustainable energy vision. In any other country that can allow some leeway to deviate from the cost efficiency principle, the focus on increasing regional equity performance would also have positive impacts on the diffusion of DREG, especially solar PV.

Acknowledgements

This work was funded by the Swiss National Science Foundation Ambizione Energy grant (No. 160563) and the partnership between Industrial Services of Geneva (SIG) and the University of Geneva.

References

[1] REN21. Renewables 2018 Global Status Report. Paris: 2018.

[2] IRENA. Renewable Capacity Statistics 2018. Abu Dhabi: International Renewable Energy Agency (IRENA); 2018.

[3] Staffell I, Jansen M, Chase A, Lewis C. Energising Britain: Progress, impacts and outlook for transforming Britain's energy system. Selby: Drax Group; 2018.

[4] Li FGN, Pye S, Strachan N. Regional winners and losers in future UK energy system transitions. Energy Strateg Rev 2016;13–14:11–31. doi:10.1016/j.esr.2016.08.002.

[5] Bridge G, Bouzarovski S, Bradshaw M, Eyre N. Geographies of energy transition: Space, place and the low-carbon economy. Energy Policy 2013;53:331–40. doi:10.1016/j.enpol.2012.10.066.

[6] Balta-Ozkan N, Watson T, Mocca E. Spatially uneven development and low carbon transitions: Insights from urban and regional planning. Energy Policy 2015;85:500–10. doi:10.1016/j.enpol.2015.05.013.

[7] Swiss Federal Council. Bundesratsbeschluss über das Ergebnis der Volksabstimmung vom 21. Mai 2017. Energiegesetz [EnG] 2017. https://www.admin.ch/opc/de/federal-gazette/2017/4865.pdf (accessed April 25, 2019).

[8] Swiss Federal Office of Energy. Schweizerische Elektrizitätsstatistik 2017. 2018.

[9] Swiss Federal Council. Energiegesetz (EnG). Energiegesetz (EnG) 2016. https://www.admin.ch/opc/de/official-compilation/2017/6839.pdf (accessed April 25, 2019).

[10] Thormeyer C, Sasse J-P, Trutnevyte E. Spatially-explicit models should consider real-world diffusion of renewable electricity: Solar PV example in Switzerland. Renew Energy 2020;145:363–74. doi:10.1016/j.renene.2019.06.017.

[11] Grunewald P. Renewable deployment: Model for a fairer distribution. Nat Energy 2017;2:17130. doi:10.1038/nenergy.2017.130.

[12] Drechsler M, Egerer J, Lange M, Masurowski F, Meyerhoff J, Oehlmann M. Efficient and equitable spatial allocation of renewable power plants at the country scale. Nat Energy 2017;2:17124. doi:10.1038/nenergy.2017.124.

[13] Pfenninger S, Hawkes A, Keirstead J. Energy systems modeling for twenty-first century energy challenges. Renew Sustain Energy Rev 2014;33:74–86. doi:10.1016/j.rser.2014.02.003.

[14] Budischak C, Sewell D, Thomson H, Mach L, Veron DE, Kempton W. Cost-minimized combinations of wind power, solar power and electrochemical storage,

powering the grid up to 99.9% of the time. J Power Sources 2013;225:60–74. doi:10.1016/j.jpowsour.2012.09.054.

[15] Fuchs A, Demiray T, Panos E, Kannan R, Kober T, Bauer C, et al. ISCHESS – Integration of stochastic renewables in the Swiss electricity supply system 2017. https://www.psi.ch/ta/PublicationTab/Final-Report-ISCHESS-Project.pdf (accessed April 25, 2019).

[16] Klagge B, Brocke T. Decentralized electricity generation from renewable sources as a chance for local economic development: a qualitative study of two pioneer regions in Germany. Energy Sustain Soc 2012;2:5. doi:10.1186/2192-0567-2-5.

[17] Fell MJ, Pye S, Hamilton I. Capturing the distributional impacts of long-term low-carbon transitions. Environ Innov Soc Transitions 2019;In Press. doi:10.1016/j.eist.2019.01.007.

[18] Hau E. Wind Turbines - Fundamentals, Technologies, Application, Economics. Springer-Verlag Berlin Heidelberg; 2006.

[19] Tsoutsos T, Frantzeskaki N, Gekas V. Environmental impacts from the solar energy technologies. Energy Policy 2005;33:289–96. doi:10.1016/S0301-4215(03)00241-6.

[20] Knoblauch TAK, Trutnevyte E. Siting enhanced geothermal systems (EGS): Heat benefits versus induced seismicity risks from an investor and societal perspective. Energy 2018;164:1311–25. doi:10.1016/j.energy.2018.04.129.

[21] Jenkins K, McCauley D, Heffron R, Stephan H, Rehner R. Energy justice: A conceptual review. Energy Res Soc Sci 2016;11:174–82. doi:10.1016/j.erss.2015.10.004.

[22] Langer K, Decker T, Roosen J, Menrad K. A qualitative analysis to understand the acceptance of wind energy in Bavaria. Renew Sustain Energy Rev 2016;64:248–59. doi:10.1016/j.rser.2016.05.084.

[23] Collins S, Deane P, Ó Gallachóir B, Pfenninger S, Staffell I. Impacts of Inter-annual Wind and Solar Variations on the European Power System. Joule 2018;2:2076–90. doi:10.1016/j.joule.2018.06.020.

[24] Grams CM, Beerli R, Pfenninger S, Staffell I, Wernli H. Balancing Europe’s wind-power output through spatial deployment informed by weather regimes. Nat Clim Chang 2017;7:557–62. doi:10.1038/NCLIMATE3338.

[25] Kempton W, Pimenta FM, Veron DE, Colle BA. Electric power from offshore wind via synoptic-scale interconnection. Proc Natl Acad Sci 2010;107:7240–5. doi:10.1073/pnas.0909075107.

[26] Delucchi MA, Jacobson MZ. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies. Energy Policy 2011;39:1170–90. doi:10.1016/j.enpol.2010.11.045.

[27] Tidemann C, Engerer N, Markham F, Doran B, Pezzey JC V. Spatial disaggregation clarifies the inequity in distributional outcomes of household solar PV installation. J Renew Sustain Energy 2019;11:035901. doi:10.1063/1.5097424.

[28] Allan GJ, McIntyre SG. Green in the heart or greens in the wallet? The spatial uptake of small-scale renewable technologies. Energy Policy 2017;102:108–15. doi:10.1016/j.enpol.2016.12.005.

[29] Yu J, Wang Z, Majumdar A, Rajagopal R. DeepSolar: A Machine Learning Framework to Efficiently Construct a Solar Deployment Database in the United States. Joule 2018;2:2605–17. doi:10.1016/j.joule.2018.11.021.

[30] Zappa W, Junginger M, van den Broek M. Is a 100% renewable European power system feasible by 2050? Appl Energy 2019;233–234:1027–50. doi:10.1016/j.apenergy.2018.08.109.

[31] Yazdanie M, Densing M, Wokaun A. The nationwide characterization and modeling of local energy systems: Quantifying the role of decentralized generation and energy resources in future communities. Energy Policy 2018;118:516–33. doi:10.1016/j.enpol.2018.02.045.

[32] Zeyringer M, Price J, Fais B, Li PH, Sharp E. Designing low-carbon power systems for Great Britain in 2050 that are robust to the spatiotemporal and inter-annual variability of weather. Nat Energy 2018;3:395–403. doi:10.1038/s41560-018-0128-x.

[33] Trotter PA, Cooper NJ, Wilson PR. A multi-criteria, long-term energy planning optimisation model with integrated on-grid and off-grid electrification – The case of Uganda. Appl Energy 2019;243:288–312. doi:10.1016/j.apenergy.2019.03.178.

[34] Sovacool BK, Sidortsov R V., Jones BR. Energy Security, Equality and Justice. London: Routledge; 2013.

[35] Chapman AJ, McLellan BC, Tezuka T. Prioritizing mitigation efforts considering co-benefits, equity and energy justice: Fossil fuel to renewable energy transition pathways. Appl Energy 2018;219:187–98. doi:10.1016/j.apenergy.2018.03.054.

[36] Höhne N, den Elzen M, Escalante D. Regional GHG reduction targets based on effort sharing: a comparison of studies. Clim Policy 2014;14:122–47. doi:10.1080/14693062.2014.849452.

[37] Dworkin R. Sovereign Virtue: Equality in Theory and Practice. Cambridge: Harvard

University Press; 2000.

[38] Bentham J. An Introduction to the Principles of Morals and Legislation. Oxford: Clarendon Press; 1789.

[39] Mill JS, Crisp R. Utilitarianism. Oxford University Press; 1998.

[40] Trutnevyte E, Stauffacher M, Schlegel M, Scholz RW. Context-specific energy strategies: Coupling energy system visions with feasible implementation scenarios. Environ Sci Technol 2012;46:9240–8. doi:10.1021/es301249p.

[41] Berntsen PB, Trutnevyte E. Ensuring diversity of national energy scenarios: Bottom-up energy system model with Modeling to Generate Alternatives. Energy 2017;126:886–98. doi:10.1016/j.energy.2017.03.043.

[42] Trutnevyte E. Does cost optimization approximate the real-world energy transition? Energy 2016;106:182–93. doi:10.1016/j.energy.2016.03.038.

[43] DeCarolis J, Daly H, Dodds P, Keppo I, Li F, McDowall W, et al. Formalizing best practice for energy system optimization modelling. Appl Energy 2017;194:184–98. doi:10.1016/j.apenergy.2017.03.001.

[44] Bauer C, Hirschberg S, Bauerle Y, Biollaz S, Calbry-Muzyka A, Cox B, et al. Potentials, costs and environmental assessment of electricity generation technologies. Swiss Fed Energy Off 2017:1–783.

[45] DeCarolis JF. Using modeling to generate alternatives (MGA) to expand our thinking on energy futures. Energy Econ 2011;33:145–52. doi:10.1016/j.eneco.2010.05.002.

[46] McJeon HC, Clarke L, Kyle P, Wise M, Hackbarth A, Bryant BP, et al. Technology interactions among low-carbon energy technologies: What can we learn from a large number of scenarios? Energy Econ 2011;33:619–31. doi:10.1016/j.eneco.2010.10.007.

[47] Trutnevyte E. EXPANSE methodology for evaluating the economic potential of renewable energy from an energy mix perspective. Appl Energy 2013;111:593–601. doi:10.1016/j.apenergy.2013.04.083.

[48] Gini C. Variabilità e mutabilità. Rome: Libreria Eredi Virgilio Veschi; 1912.

[49] Swiss Federal Office of Energy. Schweizerische Statistik der erneuerbaren Energien: Ausgabe 2017. Bern: 2018.

[50] Prognos AG. Die Energieperspektiven für die Schweiz bis 2050. Energienachfrage und Elektrizitätsangebot in der Schweiz 2000-2050. Basel: 2012.

[51] Swiss Federal Office of Energy. Potentials, costs, and environmental effects of electricity generation technologies. Synthesis. Bern: 2017.

SUPPLEMENTARY INFORMATION

Distributional trade-offs between regionally equitable and cost-efficient allocation of renewable electricity generation

Authors: **Jan-Philipp Sasse[1,2]*, Evelina Trutnevyte[1]**

[1] Renewable Energy Systems, Institute for Environmental Sciences (ISE), Section of Earth and Environmental Sciences, University of Geneva, Switzerland

[2] Institute for Environmental Decisions (IED), Department of Environmental Systems Science, ETH Zurich, Switzerland

Email: jan-philipp.sasse@unige.ch

Tel: +41 22 379 06 03

S.1 Nomenclature

n	total number of electricity generation, net import and electricity savings technologies;
N	number of technologies to be optimized;
i	set of indices of any electricity generation, net import and electricity savings technology, $i = 1,2,\dots,n$;
D	total electricity demand per municipality, in MWh/year;
x_i	generated electricity by technology i in the municipality, in MWh/year;
θ_i	own electricity use by technology i, in % (see Table SM.1);
$P_{max,i}$	maximum annual potential of generated electricity of each technology i in the municipality, in MWh/year;
$P_{min,i}$	minimum annual potential of generated electricity of each technology i in the municipality, in MWh/year, defined by currently existing (2016) electricity generators and the least-cost spatial allocation of DREG to reach the Swiss Energy Strategy 2050 target;

α_i randomly drawn number from a uniformly distributed set {-1,1} for each technology i;

c_i levelized cost of electricity, including investment, operation and maintenance, resource or fuel costs and heat credits over the technology-specific lifetime and discount factor of each technology i, in CHF/MWh (see Table SM.1);

C_{slack} the cost constraint (moving slack), which varies between 0% and 20% above minimum costs in the municipality, in CHF/MWh;

C_{min} minimum costs in the municipality, in CHF/MWh;

S.2 Mathematical formulation

This section presents the mathematical formulation of the EXPANSE model. EXPANSE is a linear programming model that generates, for each municipality individually, a diverse set of technically-feasible and cost-effective electricity supply scenarios that meet environmental, technical and cost constraints. This is achieved by applying the Modeling to Generate Alternatives (MGA) method called Efficient Random Generation (ERG) of feasible alternatives [1, 2]. This MGA technique allows EXPANSE to sample a wanted number of scenarios on the vertices of the pre-defined scenario space.

Each scenario is defined by $x, x \in R^n$, where $x_i = x_1, x_2, \dots, x_n$ is the use of each technology i in MWh/year in each municipality. The analysis is done for annual sums of electricity demand and supply. Each scenario is generated by optimizing a linear function in three steps [1, 2]. First, a random number N is drawn from a uniform distribution, where $1 \leq N \leq n$ (for example $N = 3$). N is the number of technologies that will be optimized out of n available technologies (in our case $n = 13$). In the second step, the indices i, where $1 \leq i \leq n$, are randomly drawn from a uniform distribution until the indices of a total number of N technologies are selected. This means that the technologies to be optimized are randomly selected for N number of technologies. As a result, we obtain a random set I of randomly selected indices i, for example $I = [3,5,11]$. The exact technologies are thus specified for the optimization, in this case x_3, x_5 and x_{11}. In the third step, the variables with the indices of the set I are multiplied with a randomly drawn number α_i from a uniform distribution {-1,1} and summed to form the objective function. The obtained objective function is optimized for each municipality for 2’000 times (i.e. to create a set of 2’000 scenarios):

$$max \sum_{i=1}^{n} \alpha_i x_i \quad (1)$$

subject to

$$P_{min,i} \leq x_i \leq P_{max,i} \quad (2)$$

$$\sum_{i=1}^{n} \theta_i x_i = D \quad (3)$$

$$\sum_{i=1}^{n} c_i\, x_i \leq C_{slack} \quad (4)$$

The equation (1) shows the optimization function. The equations (2) and (3) guarantee that the generated scenario is technically feasible and meets the demand constraints. Equation (4) allows for selecting only the scenarios that are cost-optimal or near cost-optimal [3, 4].

The cost constraint (called “moving slack”) limits the total costs to a certain plausible level above cost-optimal costs. C_{slack} is calculated for each municipality as follows:

$$C_{min} \leq C_{slack} \leq 1.2 \cdot C_{min} \quad (5)$$

$$C_{min} = min \sum_{i=1}^{n} c_i x_i \text{ , subject to Eq. (2-3)} \quad (6)$$

For each scenario the moving slack C_{slack} is randomly drawn from a uniform distribution and bounded between 0% and 20% above cost-optimal cost for each municipality, as shown in equation (5). The minimum cost C_{min} is calculated by optimizing the objective function (6) subject to equations (2) – (3).

S.2 Input assumptions

Electricity demand

The total Swiss electricity demand is assumed to increase from 58.2 TWh in 2016 to 70.0 TWh in 2035, as defined by the business-as-usual reference scenario of the Swiss Federal Office of Energy [5]. In order to spatially allocate the electricity demand to each municipality, GIS dataset for end-user sectors is used, including the spatial data on the number of employees in commercial sector, industries, and agriculture [6]. We further segregate these three main sectors into 20 sub-sectors (e.g., pharmaceutical industry, paper, textile) in order to account for the diversity of electricity-use intensity across these sub-sectors. Next, we allocate the electricity demand to each municipality depending on the total electricity demand shares per sector [7], sub-sector [8], and the number of employees [6]. The demand allocation for households and transport is conducted by using electricity demand shares of these sectors [7] and the population size of each municipality [9].

Electricity generation

Next, we assess the location and characteristics of the currently existing electricity generation [10, 11, 12, 13, 14] and potential for new centralized and DREG generators, net import and electricity savings due to end-use efficiency measures. The spatially-explicit electricity generation potentials of each technology are modeled individually with the following described methods.

Solar PV electricity potential is calculated based on results from the Sonnendach study [15], which estimates the maximum electricity generation potential of each building in Switzerland assuming that all rooftops can be filled with solar PV panels. In this study, we exclude the solar electricity potential from facades due to the much lower capacity factor and therefore much higher LCOE [16]. Open-field solar PV are almost non-existent in Switzerland [16] and are therefore also excluded. In order to provide a more realistic estimation for solar rooftop PV potential, we ignore rooftops smaller than $10m^2$ and apply correction factors [17] in order to account for unusable spaces, which depend on the building type (single-family, multi-family, schools, etc.) [18] and the rooftop slope (flat or slanted) [15].

Wind electricity generation potential is calculated by assessing eligible areas where wind turbines can be physically and legally installed [19]. We allocate a maximum recommended number of 1 wind turbine per 1 km^2 [20] in order to avoid the 'park effect' [21] (a downstream wind turbine within a wind park receives slower and more turbulent air flow) in order to obtain the maximum number and location of turbines. We assume the installation of popular Vestas V112 turbines and apply its power curve [22] to wind speed data at hub height with 100m by 100m spatial resolution in the form of Weibull parameters [23]. This allows us to obtain the yearly electricity generation of each potential wind turbine.

EGS electricity generation potential is estimated by evaluating available areas that are non-alpine industrial zones with low to medium seismic risk [24]. We assume 5MW plants with a yearly electricity generation capacity of 30GWh and a bore hole depth of 5km [16].

Electricity generation from biogas and woody biomass is estimated by evaluating the resource potential [25] from wet biomass (e.g., animal manure, sewage sludge) and dry biomass (e.g., forest wood, wood residues). Then, a maximum sourcing range of 30km is applied in order to account for the economic mobility of biomass resources. We assume that potential biogas plants are limited to the areas that have access to the natural gas grid [26] for methane injection.

The electricity generation potential of all other technologies (i.e., hydropower, nuclear, large gas, waste incineration) in each municipality is evaluated by adding generators that are currently planned until 2035 [13, 16] and by extrapolating the remaining predicted electricity generation potential to match future projections [16].

For all technologies except solar PV and wind, the capacity factors (see Table SM1) are obtained from current projections for the year 2035 [16] in order to calculate the yearly electricity generation based on the installed capacity. The capacity factors of wind and solar PV are spatially explicit and depend on the locally available wind and solar resources. By applying the previously described bottom-up model for solar PV and wind, we can calculate the electricity generation of each generator in each municipality and the resulting capacity factor based on the installed capacity.

Levelized costs of electricity (LCOE) and investment costs

The levelized cost of electricity of each electricity generator is given by c_i and includes investment, operation and maintenance (O&M), resource or fuel costs and heat credits discounted over each electricity generators lifetime and discount rate (Table SM1 provides the values for the year 2035, which have been estimated in other studies specifically for Switzerland [16, 24]). The levelized cost of electricity for solar PV and wind turbines are spatially-explicit, due to varying local availability of solar and wind resources. We do not consider economic incentives in our calculations. For small hydro plants, we include an additional water tax of 0.016 CHF/kWh. In the case of biogas combined and heat power (CHP), wood CHP, waste incineration, and EGS systems, we account for available district heating networks in the region, where it is possible to sell the excess heat. For these electricity generators, in addition to wind and solar PV, the LCOE are spatially explicit. Waste incinerators receive gate fees for accepting waste materials and therefore have negative fuel costs. The capital cost of EGS plants includes plant costs, pump costs, fracturing costs and well costs, where the latter contributes significantly to the total capital costs. For all LCOE calculations, we apply the currently projected technology-specific discount rates and lifetimes [16].

	Wind	*Solar PV*	*Small hydro*	*Biogas CHP*	*Wood CHP*	*Waste*	*EGS*	*Large hydro dams*	*Large run-of-river hydro*	*Large gas power plants*
Capital cost (CHF/kW$_e$)	2’160	1’410	6’750	11’600	6’350	6'000	19’400	5’995	5’995	940
Fixed O&M cost (CHF/kW$_e$/year)	102	65	169	598	742	911	600			23
Variable O&M cost (CHF/kWh$_e$)			0.016				0.07	0.013	0.015	0.22
Fuel cost (CHF/kWh$_e$)				0.076	0.209	-0.23				0.85
Heat credits (CHF/kWh$_e$)				0.034	0.22	0.006	0.203			
Capacity factor	0.06-0.36*	0.07-0.15*	0.57	0.76	0.4	0.57	0.68	0.27	0.51	0.62
Lifetime (years)	20	30	60	15	20	20	30	60	60	30
Discount rate (%)	5	5	6	3	2	2	5	6	6	6
Own electricity use (%)	0	0	1	0	0	0	5	5	1	10

** Spatially-explicit values because the electricity yield varies with the regional wind speed distribution and solar irradiation*

Table SM1. Costs, lifetimes, capacity factors and discount rates of DREG systems and key centralized technologies [16, 24]

References

[1] Chang, S. -Y, Brill, E. D., & Hopkins, L. D. (1982). Efficient random generation of feasible alternatives: a land use example. *Journal of Regional Science*, ***22***(3), 303–314.

[2] Chang, S. -Y, Brill, E. D., & Hopkins, L. D. (1982). Use of mathematical models to generate alternative solutions to water resources planning problems. *Water Resources Research*, ***18***(1), 58–64.

[3] DeCarolis, J. F. (2011). Using modeling to generate alternatives (MGA) to expand our thinking on energy futures. *Energy Economics*, ***33***(2), 145–152.

[4] Trutnevyte, E., Stauffacher, M., & Scholz, R. W. (2012). Linking stakeholder visions with resource allocation scenarios and multi-criteria assessment. *European Journal of Operational Research*, ***219***(3), 762–772.

[5] SFOE. (2013). *Energieperspektiven 2050*. Bern: Swiss Federal Office of Energy (SFOE).

[6] FSO. (2016). *Statistik der Unternehmensstruktur (STATENT), Beschäftigte und Arbeitsstätten: Geodaten*. Neuchâtel: Federal Statistical Office (FSO). Retrieved on April 25, 2019, from http://www.geostat.admin.ch

[7] SFOE. (2016). *Schweizerische Elektrizitätsstatistik - Statistik 2016*. Bern: Swiss Federal Office of Energy (SFOE).

[8] SFOE. (2016). *Energieverbrauch in der Industrie und im Dienstleistungssektor*. Bern: Swiss Federal Office of Energy (SFOE).

[9] FSO (2018). *Regional portraits 2018: key data of all communes*. Neuchâtel, Switzerland: Swiss Federal Statistical Office (FSO).

[10] SFOE. (2018). *Hydropower plants: statistics*. Bern, Switzerland: Swiss Federal Office of Energy (SFOE).

[11] SFOE (2017). *Liste aller KEV-Bezüger im Jahr 2017*. Bern, Switzerland: Swiss Federal Office of Energy (SFOE).

[12] SFOE (2018). *Wind energy plants: Geodata*. Bern, Switzerland: Swiss Federal Office of Energy (SFOE).

[13] VSE (2018). *Gaskombikraftwerk (GuD)*. Aarau, Switzerland: Verband Schweizerischer Elektrizitätsunternehmen (VSE).

[14] VBSA (2018). *Kehricht-Verwertungs-Anlagen (KVA)*. Bern, Switzerland: Verband der Betreiber Schweizerischer Abfallverwertungsanlagen (VBSA).

[15] SFOE (2016). *Solarpotentialanalyse für Sonnendach.ch – Schlussbericht*. Bern, Switzerland: Swiss Federal Office of Energy (SFOE).

[16] Bauer, C., Hirschberg, S., Bäuerle, Y., Biollaz, S., Calbry-Muzyka, A., Cox, B., Heck, T. Lehnert, M., Meier, A., Prasser, H.-M., Schenler, W., Treyer, K., Vogel, F., Wieckert, H.C., Zhang, X., Zimmermann, M., Burg, V., Bowman, G., Erni, M., Saar, M., Tran, M.Q. (2017). *Potentials, costs and environmental assessment of electricity generation technologies*. PSI, WSL, ETHZ, EPFL. Paul Scherrer Institut, Villigen PSI, Switzerland.
[17] SFOE (2016). *Sonnendach.ch: Berechnung von Potenzialen in Gemeinden*. Bern, Switzerland: Swiss Federal Office of Energy (SFOE).
[18] FSO. (2017). Register of buildings and dwellings. Neuchâtel, Switzerland: Federal Statistical Office (FSO).
[19] ARE. (2017). *Konzept Windenergie - Hinweiskarte auf Bundesinteressen für die Planung von Windenergieanlagen*. Bern: Swiss Federal Office of Spatial Development (ARE).
[20] Denholm, P., Hand, M., Jackson, M., Ong, S. (2009). *Land-Use Requirements of Modern Wind Power Plants in the United States*. Golden, USA: National Renewable Energy Laboratory (NREL).
[21] DWIA Danish Wind Industry Association. (2003). *Park Effect*. Retrieved Jan. 23, 2019 from http://drømstørre.dk/wp-content/wind/miller/windpower%20web/en/tour/wres/park.htm
[22] Vestas. (2013). *3MW Platform*. Retrieved Jan. 23, 2019 from https://www.vestas.com/
[23] SFOE. (2017). *Windatlas Schweiz: Jahresmittel der modellierten Windgeschwindigkeit und Windrichtung in 125 m Höhe über Grund*. Bern: Swiss Federal Office of Energy (SFOE). Retrieved Jan. 23, 2019 from http://www.uvek-gis.admin.ch/BFE/storymaps/EE_Windatlas/
[24] Hirschberg, S., Wiemer, S. & Burgherr, P. (2015). *Energy from the Earth – Deep Geothermal as a Resource for the Future?*. Zurich, Switzerland: vdf Hochschulverlag AG.
[25] Mohr, L., Burg, V., Thees, O., & Trutnevyte, E., Spatial hot spots and clusters of bioenergy combined with socioeconomic analysis in Switzerland, *Renewable Energy* (under review)
[26] VSG. (2018). *Verzeichnis der mit Erdgas versorgten Gemeinden und Ortschaften in der Schweiz*. Zürich, Switzerland: Association of the Swiss Gas Industry (VSG).