energies

MDPI

Article

Do We Need Gas as a Bridging Fuel? A Case Study of the Electricity System of Switzerland

Paula Díaz *, **Oscar van Vliet** and **Anthony Patt**

Climate Policy Group, Department of Environmental Systems Science, ETH Zurich, Universitätstrasse 22, 8092 Zurich, Switzerland; oscar.vanvliet@usys.ethz.ch (O.v.V.); anthony.patt@usys.ethz.ch (A.P.)
* Correspondence: paula.diaz@usys.ethz.ch; Tel.: +41-44-632-2839

Received: 5 May 2017; Accepted: 21 June 2017; Published: 28 June 2017

Abstract: Many future electricity scenarios, including those from the International Energy Agency, use natural gas to bridge the transition to renewables, in particular as a means of balancing intermittent generation from new renewables. Given that such strategies may be inconsistent with strategies to limit climate change to below 2 °C, we address the question of whether such use of gas is necessary or cost effective. We conduct a techno-economic case study of Switzerland, using a cost optimization model. We explore a range of electricity costs, comparing scenarios in which gas is used as a source of base-load power, a source of balancing capacity, and not used at all. Costs at the high end of the range show that a complete decarbonization increases system-wide costs by 3% compared to a gas bridging scenario, and 13–46% compared to a carbon-intensive scenario, depending on the relative shares of solar and wind. Costs at the low end of the range show that system-wide costs are equal or lower for both completely decarbonized and gas bridging scenarios. In conclusion, gas delivers little to no cost savings as a bridging fuel in a system that switches to wind and solar.

Keywords: concentrating solar power; wind offshore; cost projections; decarbonization; Switzerland

1. Introduction

Countries agreed at the 21st Conference of the Parties COP21 in Paris to hold climate change to less than 2 °C global average warming. This will require the elimination of greenhouse gas emissions this century and, accordingly, countries have set national targets to decarbonize their energy systems [1,2]. Currently, several technology alternatives exist to produce electricity with reduced emissions; these include biomass, geothermal, tidal, solar, and wind power [1,3,4]. Developments of energy storage technologies, e.g., electrochemical, mechanical, and thermal contribute to the enrichment of the electricity mix of developed economies [5,6]. There is, however, a great deal of evidence to suggest that the dominant set of technologies needed to achieve this decarbonization will be modern renewable energy sources, and in particular, wind and solar power, with electricity correspondingly becoming the dominant energy carrier in the economy, replacing liquid fuels [7–10]. Investment costs for wind and solar power have declined, in particular, photovoltaic (PV), as a result of economies of scale, technological advances, learning-by-doing in the technology supply chains, and reductions in financing costs associated with these becoming reliable industries [4,11]; further declines are anticipated in the future [12–16]. For example, investment in offshore wind in Europe has grown 30% annually, and this has been associated with the cost of building an offshore wind farm falling 46% over the last five years, and 22% in 2016 alone [12].

A major challenge exists with respect to wind and solar—namely, balancing their intermittent supply in order to ensure that electricity is available where and when it is needed [17–21]. Especially in the case of batteries, such storage remains expensive at a seasonal scale, although the costs have fallen significantly for diurnal variations [22]. For example, while the levelized cost of electricity (LCOE) for wind and PV in ideal locations has fallen below €0.05 per kWh, the levelized costs of battery storage currently exceed €0.20 per kWh, assuming daily charge and discharge cycles [23]. The costs of covering intermittency rises even further in the case where there are large seasonal differences in the renewable energy supply. Dealing with such seasonality would either require large excess generation capacity during some months of the year, or large energy volumes to be stored on an annual basis, with essentially one storage cycle each year, rather than every day [6]. While storage costs are declining, it will likely take at least a decade, and potentially several decades, before these have declined far enough to make it possible to cover seasonal fluctuations in supply at an affordable cost [21,24–26].

Future electricity scenarios, such as those from the International Energy Agency (IEA), make use of natural gas in order to bridge the transition gap. These scenarios cover the intermittency of wind and solar with gas peaking plants, as well as plants that provide some part of baseload capacity during particular seasons, until grid scale storage becomes sufficiently inexpensive so as to do this job. Such scenarios suggest the possibility of increasing the total generating capacity from natural gas, even as their annual utilization gradually declines [1]. In this way, the use of natural gas need not be inconsistent with reaching relatively ambitious decarbonization targets, such as 50%–80%. However, it is also clear that, ultimately, the use of natural gas would have to be discontinued in order to reach a 100% decarbonization target [27,28].

There are reasons to believe that discontinuing the use of gas in this way would lead to a great deal of stranded assets, of two sorts. The first type of stranded assets would be the generation plants themselves. Achieving the Paris objectives would require 100% emissions reductions in the electricity sector of industrialized countries as soon as 2050 [2,29], and it is foreseeable that many of the gas plants built as bridges could still have an operational life beyond then. The second type of stranded asset would be knowledge. Greatly expanding the capacity of the natural gas power supply would result in learning how to do this reliably and inexpensively, while suddenly stopping would leave this knowledge to then go unused. On the one hand, the cost of such stranded assets could be substantial, and is better to be avoided. Moreover, it may be that the prospect of stranded assets would make it attractive to continue to use gas, resulting in greater climate impacts [30].

For both reasons, it is important to explore whether it is possible to make the transition to 100% renewables in a manner that does not require massive new investments in energy storage particularly seasonal storage, and also does not make use of new natural gas capacity. This is what we do here.

This paper explores future ranges of LCOEs to analyze if a scenario with gas as a bridging fuel brings economic benefits, in the transition towards a system with high shares of renewables. We describe the specific case studied, Switzerland, in Section 2. In Section 3, we explain the different scenarios and the cost optimization method that was utilized. In Section 5, we discuss the results presented in Section 4, and provide the main conclusions.

2. Swiss Case Study

We examine the potential to move to a 100% renewable electricity supply, with no substantial new investments into storage, in the case of Switzerland. There are several reasons why the Swiss case can inform a wider transition to a fully renewable electricity system, which we spell out in this section.

First, Switzerland is a country where the daily and seasonal storage capacity is well defined, given its extensive hydropower infrastructure. That infrastructure currently supplies the country with roughly 60% of its electricity, and also includes a number of pumped storage plants [31]. At the same time, it is clear that there is little room in Switzerland to expand the hydro-power generation infrastructure, with little market incentive to expand the storage capacity [32]. While these facts mean that the situation in Switzerland is somewhat atypical of many European countries, they carry the benefit of the storage capacity being well defined. In our analysis, we assume a continuation of the current capacities for hydropower and water storage, with no new additions.

Second, Switzerland is a country that is especially vulnerable to the problem of seasonal renewable power fluctuations. Hydropower is highly seasonal, with summer production exceeding winter by

57% [33], even when making maximum use of dam storage capacity. While wind power offers many European countries a renewable power supply that peaks in winter, for Switzerland this resource is extremely limited, given the country's mountainous topography [34,35]. This leaves solar PV as the potentially dominant new renewable, but in Switzerland this is also highly seasonal, due both to latitudinal effects and the generally cloudy winters [14,36,37]. The combination of these factors means that Switzerland faces a major winter power deficit. It also faces short-term deficits in other seasons due to its small geographical size, meaning that PV output is highly spatially correlated across the entire country, with less balanced production patterns [17].

Third, Switzerland's location in central Europe, and in bordering the Mediterranean region, makes it possible to consider two very different sources of imported renewable power. On the one hand, through Italy and an undersea cable, Switzerland could conceivably have access to concentrating solar power (CSP) from northern Africa [38–40]. Morocco has, besides appropriate climatological characteristics (mean Normalized Direct Irradiance larger than 2000 $kWh/m^2/year$), a specific political scheme to foster CSP development [41,42]. Nevertheless, some implementation barriers need to be overcome, such as the lack of technical capacity among the civil service in solar projects [43]. Additionally, although private European investment is already in place, political support to CSP developments from European countries remains undefined. A potential benefit of CSP is that the integration of several hours' thermal storage capacity, as has become the industry standard, means that CSP can be used to cover evening power demands, typically a peak load period after most of all of the PV capacity has gone offline [44,45]. Making CSP somewhat less attractive is that it is also seasonal, with a summer peak, although this is less pronounced than for domestic PV supply. On the other hand, through Germany, Switzerland has access to offshore wind coming from the North Sea [46,47]. After a time of some uncertainty due to public opposition [48], a project of 3 high voltage direct current transmission lines (HVDC) started in 2015, aiming to transmit high loads of electricity from the North Sea wind farms to the south of Germany [49]. This is attractive because of the relatively high capacity factor of wind, which is also highest in winter. Both CSP and offshore wind offer large capacity expansion potentials. We analyze whether either or both of these options would be needed in order to reach a target of 100% renewable power without additional storage capacity.

Fourth and finally, Switzerland has a well-defined set of national energy targets, which can form the backbone of the scenarios that we develop here. Currently, a fleet of nuclear power plants supplies most of the remaining electricity, beyond that coming from hydro. The country intends to retire this fleet, replacing it with domestic renewables, primarily PV. It has spelled out the strategy for doing so in its Energy Strategy 2050 [50], and has adopted this strategy as a matter of law [32]. That strategy sets mid-term targets for 2035 towards decarbonization in 2050 consistent with the approach taken by the IEA. The strategy also makes use of gas as a bridging fuel for 2035. We can analyze these well-defined scenarios. At the same time, the analysis that gave rise to the Swiss energy strategy was relatively non-transparent, having been embedded in a technical report by a German consulting firm, Prognos [51]. While the report claims that they made use of high resolution data to model renewable intermittency, this is not well documented, and several authors have already demonstrated that the planned capacity expansions will require additional capacity to meet demand [14,52]. Importantly, neither the current Swiss government scenarios nor the other studies showing these to be unrealistic are considering the possibility of making use of large imports, from either the North Sea or North Africa. If we find that either is a feasible option, eliminating the need for gas, then our findings could be of value for political debates.

3. Method

To explore the use of gas as either a permanent addition to energy or as a bridging fuel, we examine three alternative scenarios. Our scenario (A) is carbon intensive, in which gas moves from being an extremely minor player in the Swiss energy system to being a mainstream energy carrier. Our scenario (B) foresees limited investment in gas, in order to balance the intermittency of new renewables, which themselves are scaled up, in order to replace most of the power lost from the closing of the nuclear fleet. This scenario matches Switzerland's energy strategy for 2050 [50]. We compare both of these to our scenario (C), in which no gas enters the Swiss power system and the country relies on 100% renewable sources instead.

In both scenarios (B) and (C) we focus on domestic development of photovoltaic (PV) and onshore wind, consistent with the country's energy strategy for 2050. We also supplement these resources with potential imports, either of wind power from the North Sea, or CSP from Morocco, or both. Figure 1 describes our assumption for these power plants, specifying the geographic locations and technologies involved. Both offshore wind and CSP are relatively unemployed technologies, for which issues of public acceptance could be fewer than is the case with large-scale onshore wind or PV installations in the European Union (EU) [53]. Offshore wind has the potential to grow rapidly in the EU. It accounted for 8% of new wind installed capacity in 2016 [54], driven by European and national policy targets towards carbonization [55,56]. A similar potential for growth exists in the case of CSP in North Africa. Many studies suggest the feasibility of MENA to provide up to 20% of Europe's electricity by 2050 [9,13,57–61]. Compared to PV, CSP offers the possibility of relatively low cost on-site thermal storage. Several hours storage has become the industry standard, allowing CSP to cover peak load periods in the evening.

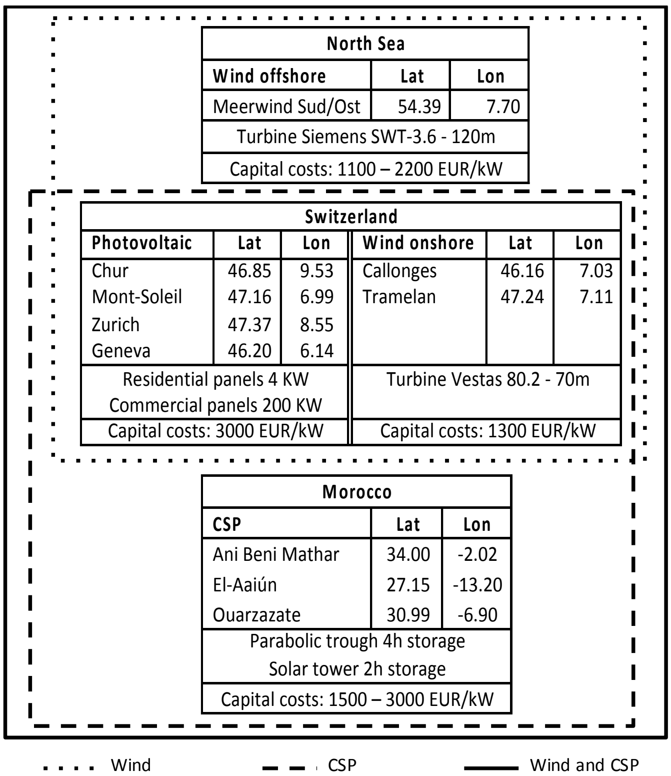


Figure 1. Technical specifications of the three configurations modeled for imports of electricity from renewables. They include high shares of Swiss domestic photovoltaic. The configurations combine imported renewables, to find the most reliable and cost-effective solution. All the locations have operational plants, except El-Aaiun, which is still under planning.

We employ a cost optimization modeling framework to cover the anticipated Swiss power demand in the years 2035 and 2050, constraining the model to match power output to demand every hour of the day. Annual electricity demand has been extracted from a previous study, used by the Swiss Federal Office of Energy to elaborate the Swiss Energy Strategy 2050, where future electricity demand is adjusted to policy measures [51]. The demand curve has been patterned after the 2014 hourly load curve, obtained from the Swiss transmission system operator, Swissgrid [62]. We use the Calliope modeling framework, which offers the needed resolution with respect to both time and space [63]. Unlike other lower resolution modeling frameworks, which constrain intermittent renewables penetration to a pre-assumed maximum, the Calliope framework allows us to investigate the requirements for over-capacity to compensate for periods during which only a small share of the intermittent renewable capacity is productive.

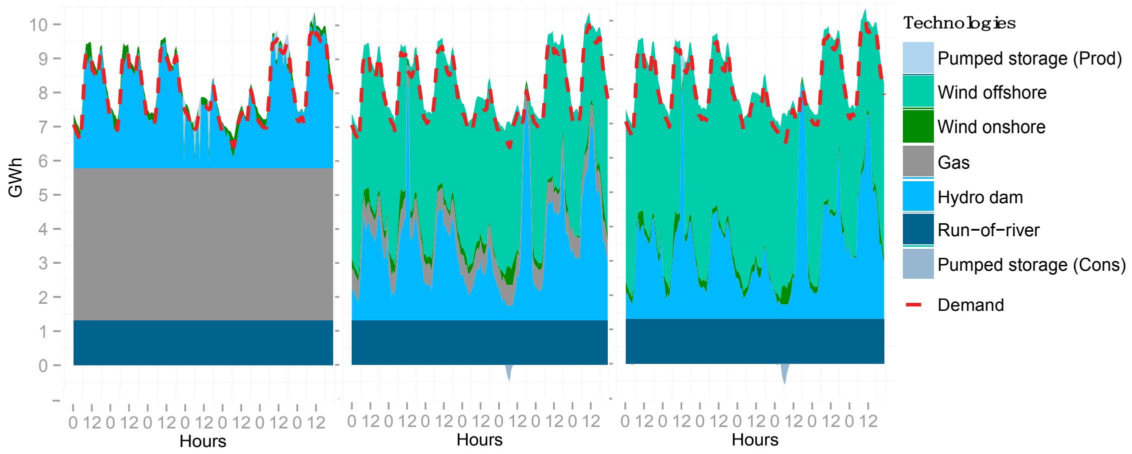
Critical to the Calliope model is the conversion of meteorological data into hourly power outputs from wind and solar facilities. Our data on solar radiation and wind speed cover a period of four years (2011–2014), using data provided by MeteoSwiss [64] for Swiss sites and the EU Joint Research Centre [65] for North Sea and Moroccan generation sites, with supplemental data also from the Research Data Archive [66]. These data have been validated through the use of power conversion data from solar and wind facilities throughout Europe [67]. To convert meteorological parameters into power output, we used the System Advisor Model (SAM) developed at the U.S. National Renewable Energy Laboratory [68]. Regarding hydropower, we disaggregated the data for run-of-river production from monthly values in historical databases to hourly values evenly distributed along the month, since more accurate resolutions are not publicly available [69]. Imports and exports are patterned on the 2014 load curve of the transmission system operator, Swissgrid [62], as a proxy for the grid balancing services that Switzerland provides to the EU grid today [62]. The connections between Switzerland and the exporting countries are assumed to be high voltage direct current transmission lines (HVDC), considering the equivalent losses of 2% per one thousand kilometers [70].

Calliope allows us to calculate LCOE for specific technologies, as well as system LCOE, weighted by volume of electricity generated. We use several technology cost components to calculate the LCOEs for our power plants in different scenarios: capital investment costs (EUR/kW), fixed operation and maintenance costs (EUR/kW/year), variable operation and maintenance costs (EUR/kWh), and variable costs, for example, fuel prices (EUR/kWh). Components of the technology cost for the technologies investigated come from sources described in Schröder, Kunz, Meiss, Mendelevitch, and Hirschhausen [15], IRENA [11] and Mehos, et al. [71]. There is uncertainty across those sources concerning future technology cost developments for both wind and CSP, and so we consider the sensitivity of our system LCOE estimates to uncertainty in wind and solar costs, specifying the sources from which varying LCOE estimates derive. The lowest CSP prices coincide with targets established, and so-far achieved, by the Sunshot initiative, with which in 2012 the U.S. Department of Energy studied the implications of making solar electricity cost-competitive with conventionally generated electricity by 2020. There is less uncertainty concerning future technology cost developments to be found in published data for gas. However, gas prices depend strongly on many factors not easy to predict, such as material opportunities, market dynamism, strategic actor behavior, focusing events, and discursive expectations about the future. Therefore, we use PSI [72] as a reference for fuel and technology costs and conduct sensitivity analysis with Combined Cycle Gas Turbines (CCGT) across this range. We apply an inflation and exchange rate to all components of technology costs, according to the reference date of publication and the projected date they are based on [73]. The resulted LCOEs include transmission costs to the extent that the model accounts for line losses, which is consistent with approaches taken in previous studies of regional energy systems [45,74,75].

Finally, we consider the possible constraints that geographic factors could impose on the scaling up of domestic renewable power in Switzerland, and imported offshore wind and CSP. With respect to domestic potentials, we base our estimated capacity constraints on figures within the country's energy strategy. With respect to offshore wind, we rely on offshore wind potential estimates made by the EEA [76], which include restrictions such as shipping routes, military use, oil and gas exploration, and tourist zones. Although these restrictions are accounted for, the amount of electricity from wind would, however, be sufficient to fulfill about 78% of the projected electricity demand in Europe in 2030 (5100 TWh/year). Regarding CSP, we use estimates made by Richts [42], Greenpeace, SolarPACES and ESTELA [61], Trieb, Schillings, Pregger, and O'Sullivan [75].

4. Results

Figure 2 illustrates the relative roles of particular technologies, according to different scenarios. All three graphs show the week in the year when gas consumption in a carbon intensive scenario would be highest, occurring in the month of January. In Figure 2a it is clear that gas is the primary source of baseload power, augmented by run-of-river hydro. Figure 2b represents the use of gas as a bridging fuel, as captured by the Swiss Energy Strategy 2050, balancing the difference between wind load and consumer demand. Figure 2c illustrates a completely decarbonized scenario. In this case, there is overcapacity of wind. On the one hand, this allows for the system to achieve complete reliability without the use of gas. On the other hand, however, in such a scenario there would be many hours of the year (977 h) when wind power is curtailed: potentially generated, but simply not used anywhere in the system. This curtailment takes place entirely in the hydropower season; run of river plants mostly produce from late March to late November, showing that wind power is used as a backup to seasonally fluctuating hydropower. This curtailment, which in average over the entire year is 11%, leads to higher costs. There is no curtailment in the scenarios utilizing gas as a bridging fuel. However, curtailment reaches about 40% of the year in in the gas intensive scenario (about 3400 h), mostly concentrated in the summer months, where Swiss hydropower is producing at its maximum availability factor.



(**a**) (**b**) (**c**)

Figure 2. Seven days with a higher requirement of gas imports (for January 2035) in the scenarios under different carbon targets: (**a**) carbon intensive; (**b**) gas as a bridging fuel as per the Swiss Energy Strategy 2050; and, (**c**) carbon free.

Not shown in Figure 2 are scenarios utilizing CSP from Morocco instead of offshore wind power. Qualitatively, the results are the same as in the North Sea scenario: in a CSP scenario gas can be reduced to a source of load-balancing power and eliminated entirely with an over-capacity in which there is substantial curtailment. Curtailment would occur primarily in summer months, to accommodate increased hydro production, although in those summer months there is a greater opportunity to store excess power in pumped storage facilities. Curtailment is more pronounced in the case of CSP import scenarios compared to those with offshore wind, because offshore wind capacity factors are highest in winter months, whereas those for CSP are highest in late spring and summer. Our model results project curtailment of 30% of CSP generation in the Moroccan import scenario, compared to 11% of wind generation in the North Sea import scenario.

Building on these results, Figure 3 shows projected least-cost system parameters for the different scenarios, with Figure 3a focusing on installed capacities, and Figure 3b on electricity production. In scenario A, which is carbon intensive, gas essentially compensates for the loss of nuclear power;

the fact that the gas capacity would have to be slightly higher in 2035 than for today's nuclear fleet (seen in Figure 3a) reflects a slightly lower projected capacity factor for gas than for nuclear. It also becomes clear that the substantially lower capacity factors for CSP than for offshore wind would require a correspondingly greater capacity investment, in order to achieve roughly the same energy output. The wind and CSP scenarios also differ in terms of investment into domestic PV. Projected costs for PV lie in between those of wind and CSP. The result of this is that in a least-cost scenario involving offshore wind, there would be no investment into PV. In the case of a CSP scenario, by contrast, domestic PV would be built up to the fullest extent possible. Finally, it is evident in Figure 3b that total energy production rises slightly from carbon intensive to wind, and then to CSP scenarios. This reflects a greater utilization of pumped storage—which has a net demand on energy—in the scenarios that are not carbon intensive. Within the wind and CSP scenarios, the slight rise from the gas bridging to carbon free scenarios reflects the effect of energy curtailment.

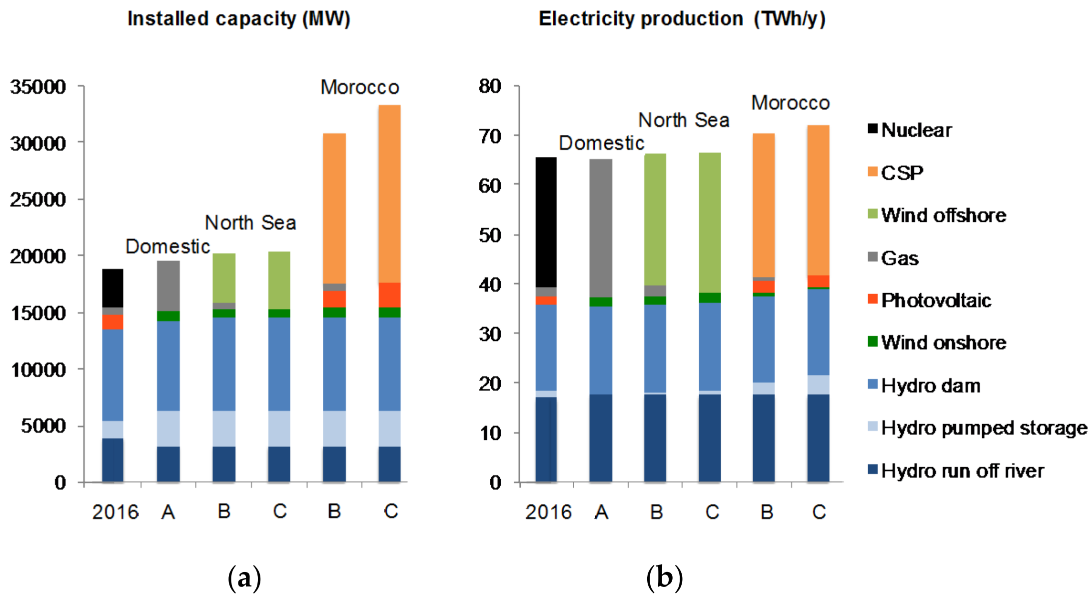


Figure 3. Installed capacity (**a**) and electricity production (**b**) per technology in each scenario in 2035, and installed capacity in Switzerland in 2016. These capacities ensure reliability, avoiding electricity shortfalls in all three scenarios: (A) carbon intensive; (B) gas as bridging fuel as per the Swiss Energy Strategy 2050; and, (C) carbon free.

It is clear from Figure 3 that the utilization of generation capacity would be greater in the wind import scenarios than in those with CSP, and as we show in subsequent figures, this corresponds as well to a likelihood of lower costs in the wind than in the CSP scenarios. We do not address the issue in this paper, but there is also reason to believe that the political constraints associated with importing power from Morocco would be greater than from Northern Europe. All of these factors beg the question of why Swiss policy makers might want to consider CSP from Morocco at all. Figure 4 provides a rationale, and that is the constraint on the total economic potential of offshore wind power in the North Sea. Current and planned wind capacities would provide an annual production of 380 TWh, whereas the estimate of the economic potential is close to ten times more, 3400 TWh. Compared to this, our model results project imports of North Sea wind to Switzerland of up to 30 TWh annually, in the case of the carbon free wind scenario. Clearly 30 TWh is substantially less than either 380 or 3400 TWh. However, were the whole of Europe to utilize North Sea wind at a level comparable to that of Switzerland, the differences between potential supply and demand would be much smaller, and give cause for concern. Scaled up to the entire European population, the Swiss carbon free wind import scenario would correspond to 2800 TWh annually, roughly 92%

of the total potential. In such a situation, it is unclear whether the countries controlling the North Sea wind resource would be enthusiastic about selling their resource, and might demand substantial resource rents. Modeling how large such rents could be is highly speculative, and we do not do so here. Their possibility, however, provides a rationale to explore the costs of Moroccan import scenarios, either as a substitute or complement to North Sea wind estimates. Previous work has demonstrated that the economic potential of CSP in North Africa exceeds total power demand in Europe by at least an order of magnitude.

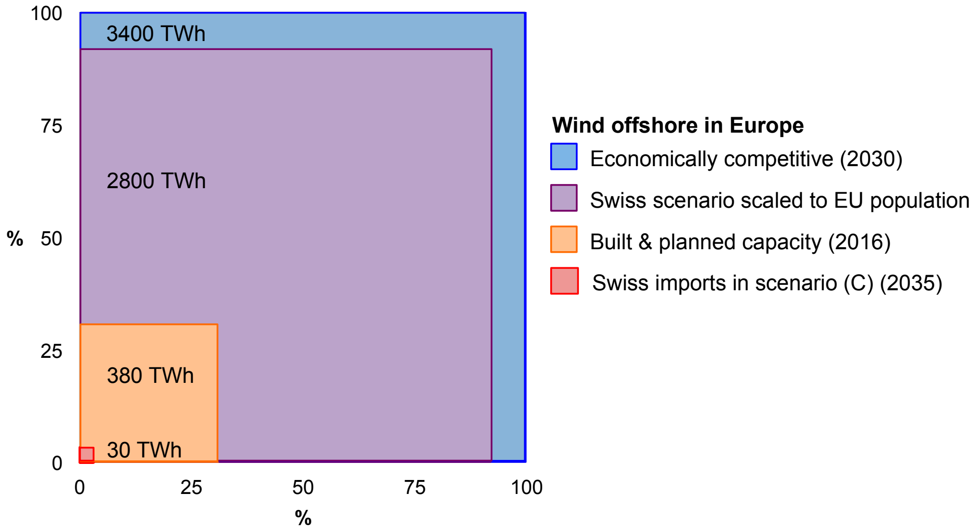


Figure 4. European energy economic potential of offshore wind, in perspective to the Swiss imports from North Sea in the carbon free scenario (C); planned production in 2016; and the Swiss consumption in the wind scenario scaled to the European level. Restrictions to the future technical potential development are applied according to economic, spatial planning, and social limitations. Data sources are [42,61,75].

Our final two figures address the issue of costs, including the issue of uncertainty. Figure 5 shows the projected levelized costs of electricity (LCOE) for the entire system, contrasting the carbon intensive with the carbon free scenarios. For all scenarios, we have constructed a Base Case with respect to costs, which represents the median of all calculated LCOEs for the different technologies. In the case of gas, there is very low diversity in LCOE estimates because of the smaller uncertainty in the cost of future gas turbines, so we present only the Base Case value. In the case of wind and even more in CSP, there is a much greater range of credible cost projections. We compare the Base Case with the credible LCOE that lies below the median for each technology. This low-end estimate is based not only on advocacy organizations such as Greenpeace, but also on governmental research labs (e.g., NREL) and intergovernmental agencies (IRENA, IEA, and the EC). In most cases, the technology-specific fraction of the system LCOE is lower than the system LCOE, meaning that dispatchable technologies raise the costs of the system. In the case of IRENA technology costs projections, the CSP fraction of LCOE is more expensive than the system LCOE, leading to an increase in the system costs. Estimating the relative likelihood or confidence in these different projections lies outside of the scope of our analysis. It is clear, however, that if the lower cost estimates prove to be accurate, then the carbon free scenarios can be had at costs equal to or lower than those for the Base Case carbon intensive estimates.

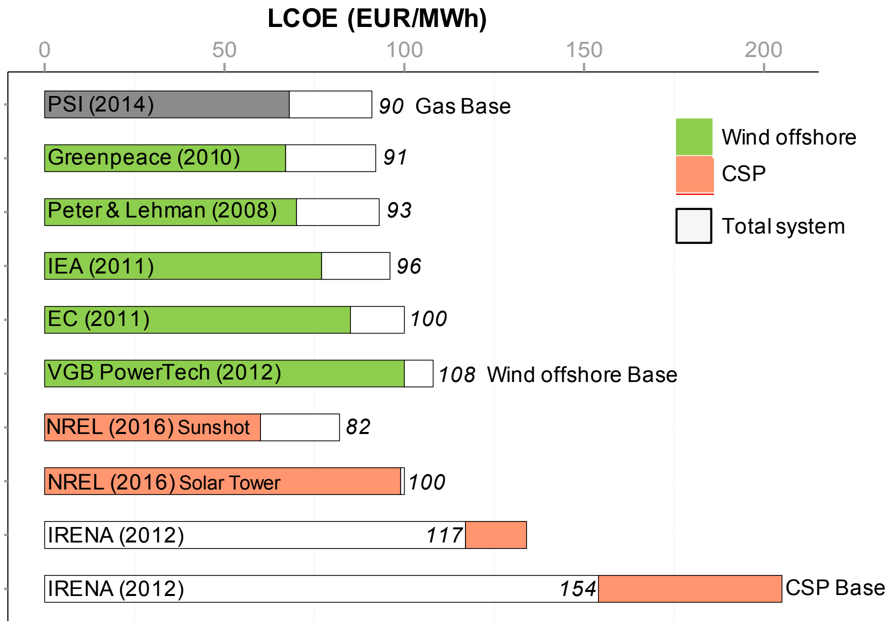


Figure 5. Lowest system levelized cost of electricity (LCOE) for the Swiss electricity system (2035) for the carbon free configuration (C) in comparison to the Base Cases. LCOEs are calculated using technology costs projections of offshore wind and CSP from the authors named in the bars. The fraction of the system LCOE that the technology-specific LCOE represents is depicted in color. Data sources, from top to bottom, are references [72], [77], [78], [79], [56], [80], [71] and [11].

Figure 6 provides the full set of cost information for the different scenarios. In the case of the carbon intensive scenario, which relies exclusively on domestic power generation involving a large proportion of gas, the range of projected LCOE values lies between €89–90 per MWh. As previously noted, the narrowness of this range reflects the limited number of credible estimates for future gas costs, combined with the fact that the balance of the system is already largely in place, and therefore highly certain. The two scenarios involving North Sea wind imports, either to reduce the use of gas to that of a bridging fuel or eliminate it entirely, range from a low of €91 per MWh to highs of €106–108 per MWh. We make three observations: first, the lower ends of both wind ranges are comparable to those for the carbon intensive scenario; second, the upper end of the right-hand range is 20% higher in terms of energy costs, which compares favorably to the much higher volatility observed in energy prices in recent years; and third, the move from the gas bridging scenario implicit in the Swiss Energy Strategy 2050 to a carbon free scenario, in the case of wind imports, carries virtually no cost implications. While the carbon free scenario would entail curtailment of wind power, this has a negligible effect on overall power costs.

Moving further to the right in Figure 6, it is clear that the uncertainty associated with CSP imports is much greater, with the range of credible cost projections lying both somewhat below those for carbon intensive and wind, and also extending substantially higher. Moreover, the added costs of achieving a carbon free outcome compared to a gas bridging case are greater in the case of CSP imports than for wind, although if in fact the lower technology cost projections for CSP turn out to be accurate, there would be no added cost. Finally, the two bars to the right present results for least-cost scenarios, making use of both wind and CSP. The precise ratios of wind to CSP in these scenarios differ according to their location within the uncertainty bars. In the carbon free scenario, 70% of the imported energy comes from wind, and 30% from CSP. It is noteworthy that in these scenarios the range of uncertainty is lower than for either the wind-only or CSP-only scenarios, as the model is able to take advantage of the flexibility to adjust capacities between the two locations to account for differences in costs.

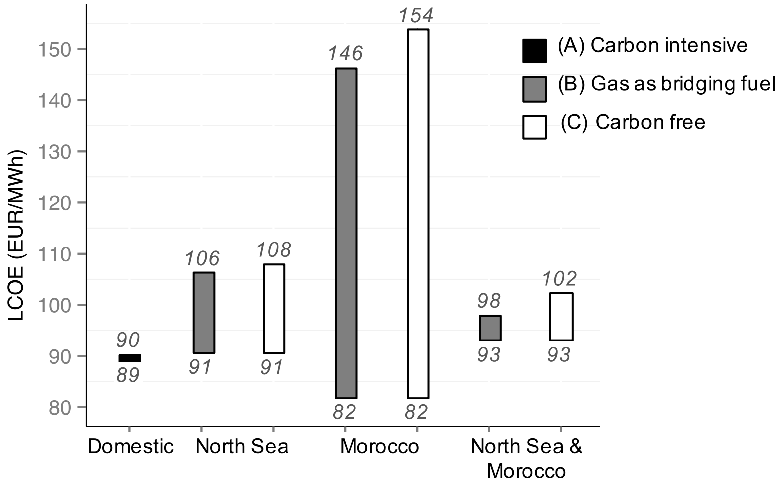


Figure 6. Ranges of weighted LCOE for the scenarios in the short term (2035). The costs have been calculated using technology cost projections of various authors for renewable technologies (shown in Figure 5), and may be open to some degree of debate. The costs in importing scenarios (North Sea and Morocco) are calculated for two levels of carbon consumption: (B) gas as a bridging fuel, as per the Swiss Energy Strategy 2050, and (C) carbon free. The Domestic scenario is gas intensive and does not include imports. LCOE does not include externalities.

5. Discussion and Conclusions

We modeled the total costs of three policy scenarios for the Swiss power system: carbon intensive, gas as a bridging fuel to balance the intermittency of high shares of solar and wind power, and completely carbon free. Our results are somewhat sensitive to alternative assumptions about the future costs of solar and wind power. Assuming costs are at the high end of the range for either technology, complete decarbonization increases system-wide LCOE values by 3% compared to the bridging scenario, and 13–46% compared to a carbon intensive scenario, depending on the relative shares of solar and wind. Assuming solar and wind costs at the low end of their respective ranges, system-wide LCOE values are identical across completely decarbonized and gas bridging scenarios. Moreover, the additional cost of either relative to the carbon intensive scenario is less than 2% in the case of a wind dominated system, whereas in a system relying on CSP with thermal storage the completely decarbonized system delivers almost close to a 10% cost reduction. Previous studies have quantified cost reductions for single renewable technologies [13,16,71,81], and we have shown this to also be the case for a national electricity system with multiple technologies.

An important caveat to this finding is that our range of cost estimates for natural gas are extremely narrow, representing the difficulty of forecasting these markets in a quantitatively robust manner, as well as the fact that significant price changes for gas could alter our relative cost estimates. Subject to this caveat, however, it is clear that utilizing gas as a bridging fuel, to balance intermittency in a system dominated by wind and solar, delivers little to no benefit in terms of cost savings. Our results present an alternative to previous electricity scenarios, such as those from the IEA [1], that made use of natural gas to bridge the energy transition. Whether or not using gas as a source of baseload power delivers cost savings relative to a system in which renewables take on this function, is sensitive to current uncertainties about future technology costs. As other studies have shown, for example, for CSP in Sub-Saharan Africa [41], it is important to note that today's policy choices can determine whether the conditions under which a renewables' dominated system is less expensive than a carbon intensive system come to exist. Policy support today for CSP with thermal storage is the precondition for this outcome [71]. It is also important to note that none of our estimates include measures that internalize the social cost of carbon, such as through an emissions tax.

The results in this study apply to the specific case of Switzerland. Switzerland is similar to many other mountainous European countries–in Scandinavia, the Alpine regions, and the Balkans–in terms of having a large hydropower capacity or potential relative to its solar and wind resources. Such countries have the benefit of compensating the fluctuations of intermittent renewables with their hydro resource, either through the use of storage dams or pumped storage facilities [82–84]. For example, in the CSP scenario, curtailment can be reduced by using the overcapacity to pump water to storage for production on demand. This has a direct effect on the need for thermal storage capacity in the Swiss scenarios, which is relatively low: 2 to 4 h. This would ultimately translate in a reduction of generation costs, depending on the costs of both CSP and pumped storage. Other authors have shown little cost increase, with high penetration of renewables for different electricity systems, for example in the UK [63]. In the case of Switzerland, the flexibility provided by gas is not necessary to compensate supply fluctuations. Other electricity systems would probably benefit from CSP with a higher thermal storage capacity [41,63].

It is also possible to imagine, but difficult to predict, that the costs of other storage technologies, such as batteries or compressed air, could fall to be comparable with that of hydro [26]. In such a situation, our results would apply more generally. In the absence of such conditions, countries like Switzerland would continue to provide services to balance the wider European transmission grid, as they do today and as we have modeled [82–84]. Indirectly, then, our results suggest that Switzerland could continue to provide these services, at no additional cost, while also making the transition to 100% renewable power for its own domestic market.

Our results are qualitatively consistent with the results from modeling studies at a much greater geographic scale and lower temporal resolution (e.g., [23,85]). These reports of international institutions show incremental costs of single technologies to be at the same level as fossil fuel systems. We show this to be the case for the electricity costs of a single country, focusing on a single power system and corresponding to the hourly weather data of specific locations. Our results are also consistent with authors who have concluded that balancing patterns of anti-correlated wind and solar power increases the stability of power production [17]. Our scenarios show that investing in renewable capital costs reductions, for offshore wind and/or CSP, would provide a reliable and competitive source of electricity, alternative to carbon intensive systems.

Acknowledgments: The study was carried out as part of the New Risks project, funded as part of the National Research Program 70 of the Swiss National Science Foundation. The authors would like to thank Stefan Pfenninger and Beat Faas for their invaluable technical assistance. We are also very grateful to several experts, who provided us with generous information and recommendations.

Author Contributions: Oscar van Vliet and Anthony Patt conceived and designed the experiments; Paula Díaz performed the experiments and analyzed the data; Paula Díaz, Oscar van Vliet, and Anthony Patt wrote the paper.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. International Energy Agency (IEA). *Energy and Climate Change: World Energy Outlook Special Report*; IEA: Paris, France, 2015.
2. United Nations Framework Convention on Climate Change (UNFCCC). Adoption of the Paris Agreement. In Proceedings of the 2015 United Nations Climate Change Conference, Paris, France, 30 November–12 December 2015.
3. Kyriakopoulos, G.L.; Arabatzis, G.; Chalikias, M. Renewables exploitation for energy production and biomass use for electricity generation. A multi-parametric literature-based review. *AIMS Energy* **2016**, *4*, 762–803. [CrossRef]
4. Renewable Energy Policy Network for the 21st Century (REN21). *Renewables Global Futures Report: Great Debates Towards 100% Renewable Energy*; REN21: Paris, France, 2017.
5. Kyriakopoulos, G.L.; Arabatzis, G. Electrical energy storage systems in electricity generation: Energy policies, innovative technologies, and regulatory regimes. *Renew. Sustain. Energy Rev.* **2016**, *56*, 1044–1067. [CrossRef]

6. Jülch, V. Comparison of electricity storage options using levelized cost of storage (LCOS) method. *Appl. Energy* **2016**, *183*, 1594–1606. [CrossRef]
7. Patt, A. *Transforming Energy: Solving Climate Change with Technology Policy*; Cambridge University Press: Cambridge, UK, 2015.
8. Global Energy Assessment (GEA). *The Global Energy Assessment*; Cambridge University Press: Cambridge, UK, 2012.
9. European Climate Foundation (ECF). *Roadmap 2050: A Practical Guide to a Prosperous, Low-Carbon Europe*; European Climate Foundation: The Hague, The Netherlands, 2010.
10. International Energy Agency (IEA). *Energy Technology Perspectives 2014: Harnessing Electricity's Potential*; International Energy Agency: Paris, France, 2014.
11. International Renewable Energy Agency (IRENA). *Irena Working Paper: Renewable Energy Technologies: Cost Analysis Series. Power Sector. Concentrating Solar Power*; International Renewable Energy Agency: Abu Dhabi, UAE, 2012.
12. Shankleman, J.; Parkin, B. Wind power blows through nuclear, coal as costs drop at sea. *Bloomberg*, 9 March 2017.
13. European Academies Science Advisory Council (EASAC). *Concentrating Solar Power: Its Potential Contribution to a Sustainable Energy Future*; European Academies Science Advisory Council: Cardiff, UK, 2011; p. 58.
14. Densing, M.; Hirschberg, S.; Turton, H. *Review of Swiss Electricity Scenarios 2050*; Paul Scherrer Institute (PSI): Villigen, Switzerland, 2014.
15. Schröder, A.; Kunz, F.; Meiss, J.; Mendelevitch, R.; Hirschhausen, C.V. *Current and Prospective Costs of Electricity Generation Until 2050*; DIW-Deutsches Institut für Wirtschaftsforschung: Berlin, Germany, 2013.
16. Hobohm, J.; Krampe, L.; Peter, F.; Gerken, A.; Heinrich, P.; Richter, M. *Cost Reduction Potentials of Offshore Wind Power in Germany*; Prognos AG & Fichtner GmbH & Co. KG: Berlin, Germany, 2013.
17. Santos-Alamillos, F.J.; Pozo-Vázquez, D.; Ruiz-Arias, J.A.; von Bremen, L.; Tovar-Pescador, J. Combining wind farms with concentrating solar plants to provide stable renewable power. *Renew. Energy* **2015**, *76*, 539–550. [CrossRef]
18. Grave, K.; Paulus, M.; Lindenberger, D. A method for estimating security of electricity supply from intermittent sources: Scenarios for Germany until 2030. *Energy Policy* **2012**, *46*, 193–202. [CrossRef]
19. Hall, P.J.; Bain, E.J. Energy-storage technologies and electricity generation. *Energy Policy* **2008**, *36*, 4352–4355. [CrossRef]
20. Fthenakis, V.; Mason, J.E.; Zweibel, K. The technical, geographical, and economic feasibility for solar energy to supply the energy needs of the us. *Energy Policy* **2009**, *37*, 387–399. [CrossRef]
21. Krajačić, G.; Duić, N.; Zmijarević, Z.; Mathiesen, B.V.; Vučinić, A.A.; da Graça Carvalho, M. Planning for a 100% independent energy system based on smart energy storage for integration of renewables and CO_2 emissions reduction. *Appl. Therm. Eng.* **2011**, *31*, 2073–2083. [CrossRef]
22. Brouwer, A.S.; Broek, M.V.D.; Zappa, W.; Turkenburg, W.C.; Faaij, A. Least-cost options for integrating intermittent renewables in low-carbon power systems. *Appl. Energy* **2016**, *161*, 48–74. [CrossRef]
23. International Renewable Energy Agency (IRENA). *Renewable Power Generation Costs in 2014*; International Renewable Energy Agency: Masdar, UAE, 2015.
24. Giannakopoulou, E.; Henbest, S. *New Energy Outlook 2016 (NEO). Long-Term Projections of the Global Energy Sector. Executive Summary*; Bloomberg New Energy Finance: New York, NY, USA, 2016.
25. Diorio, N.; Dobos, A.; Janzou, S. *Economic Analysis Case Studies of Battery Energy Storage with SAM*; National Renewable Energy Laboratory: Golden, CO, USA, 2015.
26. Bundesamt für Energie (BFE). *Energiespeicher in der Schweiz*; Bundesamt für Energie: Bern, Switzerland, 2013.
27. Schaeffer, M.; Rogelj, J.; Roming, N.; Sferra, F.; Hare, B.; Serdeczny, O. *Feasibility of Limiting Warming to 1.5 and 2 °C*; Climate Analytics: Berlin, Germany, 2015; p. 20.
28. Intergovernmental Panel on Climate Change (IPCC). *Climate Change 2007 the Physical Science Basis*; Cambridge University Press: Cambridge, UK, 2007.
29. International Energy Agency (IEA). *CO_2 Emissions from Fuel Dombustion-2016 Edition-Key CO_2 Emissions Trends*; International Energy Agency: Paris, France, 2016.
30. Piot, M. Energiestrategie 2050 der schweiz. In *13 Symposium Energieinnovation*; TU Graz: Graz, Austria, 2014; p. 28.
31. Bundesamt für Energie (BFE). *Schweizerische Elektrizitätsstatistik 2015*; Bundesamt für Energie (BFE): Bern, Switzerland, 2016; p. 52.
32. Anon. Energiegesetz. In *EnG*; Bundeskanzlei: Bern, Switzerland, 2016; pp. 7683–7730.

33. Bundesamt für Energie (BFE). *Gesamte Erzeugung und Abgabe Elektrischer Energie in der Schweiz*; Bundesamt für Energie (BFE): Bern, Switzerland, 2016.
34. Hübner, G.; Löffler, E.; Hampl, N.; Wüstenhagen, R. *Wirkungen Von Windkraftanlagen Auf Anwohner in der Schweiz*; Einflussfaktoren und Empfehlungen-Abschlussbericht: Halle, Germany, 2013.
35. Kruyt, B.; Lehning, M.; Kahl, A. Potential contributions of wind power to a stable and highly renewable Swiss power supply. *Appl. Energy* **2017**, *192*, 1–11. [CrossRef]
36. Marcucci, A.; Turton, H. Swiss energy strategies under global climate change and nuclear policy uncertainty. *Swiss J. Econ. Stat.* **2012**, *148*, 317–346.
37. Weidmann, N.O. Transformation Strategies Towards a Sustainable Swiss Energy System: An Energy-Economic Scenario Analysis. Ph.D. Thesis, ETHZ, Zürich, Switzerland, 2013.
38. Trieb, F.; Kern, J.; Caldés, N.; Rua, C.D.L.; Frieden, D.; Tuerk, A. Rescuing the concept of solar electricity transfer from North Africa to Europe. *Int. J. Energy Sect. Manag.* **2016**, *10*, 448–473. [CrossRef]
39. Battaglini, A.; Lilliestam, J.; Haas, A.; Patt, A. Development of supersmart grids for a more efficient utilisation of electricity from renewable sources. *J. Clean. Prod.* **2009**, *17*, 911–918. [CrossRef]
40. Purvins, A.; Wilkening, H.; Fulli, G.; Tzimas, E.; Celli, G.; Mocci, S.; Pilo, F.; Tedde, S. A european supergrid for renewable energy: Local impacts and far-reaching challenges. *J. Clean. Prod.* **2011**, *19*, 1909–1916. [CrossRef]
41. Lilliestam, J.; Labordena, M.; Patt, A.; Pfenninger, S. Empirically observed learning rates for concentrating solar power and their responses to regime change. *Nat. Energy* **2017**, *2*. [CrossRef]
42. Richts, C. The moroccan solar plan. A Comparative Analysis of CSP and PV Utilization Until 2020. Master's Thesis, University of Kassel, Kassel, Germany, 15 February 2012.
43. Komendantova, N.; Patt, A.; Barras, L.; Battaglini, A. Perception of risks in renewable energy projects: The case of concentrated solar power in north Africa. *Energy Policy* **2012**, *40*, 103–109. [CrossRef]
44. Pfenninger, S.; Gauche, P.; Lilliestam, J.; Damerau, K.; Wagner, F.; Patt, A. Potential for concentrating solar power to provide baseload and dispatchable power. *Nat. Clim. Chang.* **2014**, *4*, 689–692. [CrossRef]
45. Labordena, M.; Lilliestam, J. Cost and transmission requirements for reliable solar electricity from deserts in China and the United States. *Energy Procedia* **2015**, *76*, 77–86. [CrossRef]
46. Fairley, P. Germany takes the lead in HVDC. New developments in high-voltage DC electronics could herald an epic shift in energy delivery. *IEEE Spectrum*, 29 April 2013.
47. Weigt, H.; Jeske, T.; Leuthold, F.; Hirschhausen, C.V. "Take the long way down": Integration of large-scale north sea wind using HVDC transmission. *Energy Policy* **2010**, *38*, 3164–3173. [CrossRef]
48. Neukirch, M. Protests against german electricity grid extension as a new social movement? A journey into the areas of conflict. *Energy Sustain. Soc.* **2016**, *6*, 4. [CrossRef]
49. Amprion. Ultranet-projektbeschreibung. Available online: http://netzausbau.amprion.net/projekte/ultranet/downloads (accessed on 12 May 2016).
50. Bundesamt für Energie (BFE). *Botschaft Zum Ersten Massnahmenpaket der Energiestrategie 2050 (Revision des Energierechts) und Zur Volksinitiative*; Bundesamt für Energie (BFE): Bern, Switzerland, 2013.
51. Prognos AG. *Die Energieperspektiven Für die Schweiz Bis 2050. Energienachfrage und Elektrizitätsangebot in der Schweiz 2000–2050*; Bundesamt für Energie (BFE): Basel, Switzerland, 2012; p. 842.
52. Gunzinger, A. *Kraftwerk Schweiz: Plädoyer Für Eine Energiewende Mit Zukunft*; Zytglogge: Basel, Switzerland, 2015.
53. Hanger, S.; Komendantova, N.; Schinke, B.; Zejli, D.; Ihlal, A.; Patt, A. Community acceptance of large-scale solar energy installations in developing countries: Evidence from Morocco. *Energy Res. Soc. Sci.* **2016**, *14*, 80–89. [CrossRef]
54. Nghiem, A.; Mbistrova, A. *Wind in Power. 2016 European Statistics*; WindEurope: Brussels, Belgium, 2017.
55. Klessmann, C.; Nabe, C.; Burges, K. Pros and cons of exposing renewables to electricity market risks—A comparison of the market integration approaches in Germany, Spain, and the UK. *Energy Policy* **2008**, *36*, 3646–3661. [CrossRef]
56. European Commission (EC). *Communication from the Commission to the Council, the European Parliament, the European Economic and Social Committee and the Committee of the Regions on Energy Roadmap 2050*; COM(2011) 885 Final; European Commission (EC): Brussels, Belgium, 2011.
57. Zickfeld, F.; Wieland, A. *Desert Power 2050. Perspectives on a Sustainable Power System for Eumena*; Dii GmbH: Munich, Germany, 2012.

58. Broesamle, H.; Mannstein, H.; Schillings, C.; Trieb, F. Assessment of solar electricity potentials in north Africa based on satellite data and a geographic information system. *Sol. Energy* **2001**, *70*, 1–12. [CrossRef]
59. International Energy Agency (IEA). *Technology Roadmap. Concentrating Solar Power*; International Energy Agency: Paris, France, 2010.
60. German Aerospace Center (DLR). *Trans-csp Trans-Mediterranean Interconnection for Concentrating Solar Power*; DLR: Köln, Germany, 2006.
61. Richte, C. *Concentrating Solar Power. Global Outlook 09. Why Renewable Energy is Hot*; Greenpeace: Amsterdam, The Netherlands; SolarPACES: Tabernas, Spain; ESTELA: Brussels, Belgium, 2009.
62. Swissgrid. *Aggregated Energy Data of the Control Block Switzerland*; Transmission System Operator of Switzerland: Laufenburg, Switzerland, 2015.
63. Pfenninger, S.; Keirstead, J. Renewables, nuclear, or fossil fuels? Scenarios for great britain's power system considering costs, emissions and energy security. *Appl. Energy* **2015**, *152*, 83–93. [CrossRef]
64. MeteoSwiss. *Idaweb Swiss Meteorological Data*; Federal Office of Meteorology and Climatology: Zurich, Switzerland, 2015.
65. JRC. *Photovoltaic Geographical Information System (PVGIS)*; Joint Research Centre. European Commission: Ispra, Italy, 2015.
66. Saha, S.; Moorthi, S.; Wu, X.; Wang, J.; Nadiga, S.; Tripp, P.; Behringer, D.; Hou, Y.T.; Chuang, H.Y.; Iredell, M.; et al. *Ncep Climate Forecast System Version 2 (CFSV2) Selected Hourly Time-series Products*; Research Data Archive at the National Center for Atmospheric Research, Computational and Information Systems Laboratory: Boulder, CO, USA, 2011.
67. Pfenninger, S.; Staffell, I. Long-term patterns of european PV output using 30 years of validated hourly reanalysis and satellite data. *Energy* **2016**, *114*, 1251–1265. [CrossRef]
68. National Renewable Energy Laboratory (NREL). *System Advisor Model (SAM)*; NREL: Golden, CO, USA, 2014.
69. Thürler, G. *Statistik der Wasserkraftanlagen der Schweiz*; Bundesamt für Energie (BFE): Ittigen, Switzerland, 2014.
70. ENTSO-E. *Regional Investment Plan 2014. Continental Central South. Final*; European Network of Transmission System Operators for Electricity: Brussels, Belgium, 2014; p. 274.
71. Mehos, M.; Turchi, C.; Jorgens, J. *On the Path to Sunshot: Advancing Concentrating Solar Power Technology, Performance, and Dispatchability*; National Renewable Energy Laboratory: Golden, CO, USA, 2016.
72. PSI. *Switzerland Energy Transition Scenarios–Development and Application of the Swiss Times Energy System Model (stem)*; PSI: Villigen, Switzerland, 2014; p. 126.
73. Eurostat. *Hicp–Annual Percentage Changes, Breakdown by Purpose of Consumption*; Eurostat: Luxembourg, 2016.
74. Czisch, G.; Giebel, G.; Keramane, A. Totally renewable electricity supply: A European/trans-European example. *Medenergie* **2008**, *27*, 1–19.
75. Trieb, F.; Schillings, C.; Pregger, T.; O'Sullivan, M. Solar electricity imports from the middle east and north africa to Europe. *Energy Policy* **2012**, *42*, 341–353. [CrossRef]
76. European Environment Agency (EEA). *Europe's Onshore and Offshore Wind Energy Potential. An Assessment of Environmental and Economic Constraints*; European Environment Agency's European Topic Centre for Air and Climate Change (ETC/ACC): Luxembourg, 2009; p. 85.
77. Greenpeace. *Energy (R) Evolution-A Sustainable World Energy Outlook*; Primavera Quint: Amsterdam, The Netherlands, 2010.
78. Peter, S.; Lehmann, H. *Renewable Energy Outlook 2030. Energy Watch Group Global Renewable Energy Scenarios*; Energy Watch Group & Ludwig-Boelkow-Foundation: Berlin, Germany, 2008.
79. International Energy Agency (IEA). *World Energy Model–Methodology and Assumptions*; International Energy Agency: Paris, France, 2011.
80. VGB PowerTech. *Investment and Operation Cost Figures–Generation Portfolio*; VGB PowerTech: Essen, Germany, 2012.
81. Bolinger, M.; Wiser, R. Understanding wind turbine price trends in the U.S. Over the past decade. *Energy Policy* **2012**, *42*, 628–641. [CrossRef]
82. Brugger, E.A.; Dietrich, P.; Gessler, R.; Kaiser, T.; Vellacott, T.; Wokaun, A.; Zepf, N.; Wettstein-Strässle, D. *Energie-strategie 2050. Impulse Für die Schweizerische Energiepolitik*; Energie Trialog Schweiz: Zürich, Switzerland, 2009.
83. Hildmann, M.; Ulbig, A.; Andersson, G. Electricity grid in-feed from renewable sources: A risk for pumped-storage hydro plants? In Proceedings of the 2011 8th International Conference on the European Energy Market (EEM), Zagreb, Croatia, 25–27 May 2011; pp. 185–190.

84. Singh, A.; Willi, D.; Chokani, N.; Abhari, R.S. Optimal power flow analysis of a Switzerland's transmission system for long-term capacity planning. *Renew. Sustain. Energy Rev.* **2014**, *34*, 596–607. [CrossRef]
85. Fischedick, M.; Schaeffer, R.; Adedoyin, A.; Akai, M.; Bruckner, T.; Clarke, L.; Krey, V.; Savolainen, I.; Teske, S.; Ürge-Vorsatz, D.; et al. *Mitigation Potential and Costs*; Cambridge University Press: Cambridge, UK, 2011.