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Market Integration, Renewable Energy Expansion, Interconnector Capacity Investment and their Impact on the Swiss Electricity Market

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Für den Inhalt und die Schlussfolgerungen sind ausschliesslich die Autoren dieses Berichts verantwortlich.

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Zusammenfassung

Diese Studie untersucht die Marktintegration im europäischen Strommarkt mit einem Fokus auf die Schweiz. Die Schätzung des Grads an Marktintegration erfolgt unter Zuhilfenahme von unilateralen Angebot- und Nachfrageschocks wie der Stromerzeugung aus volatilen, erneuerbaren Energiequellen, die Nichtverfügbarkeit von Erzeugungsanlagen und nationalen Feiertagen. Diese exogenen Ereignisse beeinflussen den schweizerischen Strompreis und ermöglichen die Schätzung des Grads an Marktintegration, indem diese Einflüsse nach Vorliegen eines Engpasses an den jeweiligen schweizerischen Stromgrenzen zu den Nachbar-Preiszonen unterschieden werden. Mittels einer parametrischen Instrumentenschätzung können Als-Ob-Preise berechnet werden. D.h. es können für Preise aus Engpasssituationen hypothetische Preise ohne das Vorliegen von Engpasssituationen bestimmt werden. Für die Analyse werden Daten zu stündlichen Strompreisen und deren Determinanten in der Schweiz und Nachbar-Preiszonen aus den Jahren 2015 und 2016 verwendet. Die Analyse zeigt, dass Maßnahmen zur Engpassbeseitigung an der schweizerischen/deutsch-österreichischen Grenze, wie etwa der Ausbau von Interkonnektorkapazität, schweizerische Strompreise reduzieren können. Dies trifft in einem geringeren Maße ebenfalls für die schweizerische/französische Grenze zu, aber nicht für die schweizerische/italienische Grenze. Es zeigt sich für die Schweiz als Ganzes, dass Strompreise in Engpasssituationen um etwa fünf Prozent höher sind als die hypothetischen Als-Ob-Preise.

Résumé

Nous étudions l'intégration du marché de l'électricité suisse. Notre approche dans l'examen du degré d'intégration utilise des chocs unilatéraux de la demande et de l'offre tels que la génération des énergies renouvelables intermittentes, l'indisponibilité des unités de production et les congés nationaux. Ces événements exogènes affectent les prix de l'électricité en Suisse et permettent d'estimer le niveau d'intégration du marché en différenciant leurs effets dans des situations congestionnées et non-congestionnées. L'utilisation d'informations sur des situations congestionnées et non-congestionnées nous permet de calculer les “comme-si” prix dans une estimation paramétrique à l'aide de méthode des variables instrumentales. C'est-à-dire que nous pouvons simuler les prix de l'électricité suisse hypothétiques, non-congestionnées dans les situations congestionnées. En utilisant les prix horaires de l'électricité et ses déterminants concernant la Suisse et les pays voisins de 2015 et 2016, nous constatons qu'une expansion de la capacité d'interconnexion à la frontière allemande/autrichienne-suisse pourrait diminuer les prix de l'électricité suisse. D'une manière plus atténuée, il en va de même pour la frontière franco-suisse, mais pas pour la frontière italienne-suisse. Pour l'ensemble de la Suisse, les prix dans les situations congestionnées sont environ cinq pour cent plus élevés que les “comme-si” prix hypothétiques.

Abstract

We investigate market integration in European electricity markets with a focus on Switzerland. Our approach in examining the degree of integration is taking advantage of unilateral demand and supply shocks such as the generation from volatile renewable resources, the unavailability of generation units, and national holidays. These exogenous events affect electricity prices in Switzerland and allow estimating the level of market integration by disentangling their effects in congested and non-congested situations. Exploiting information on congested and non-congested situations in parametric instrumental-variable estimation permits computing but-if prices. That is, we can assess hypothetical,

non-congested Swiss electricity prices in congested situations. Using data on hourly electricity prices and its determinants regarding Switzerland and neighboring countries from 2015 and 2016, we find that an expansion of interconnector capacity at the German-Austrian/Swiss border could decrease Swiss electricity prices. In a more attenuated way, the same holds true for the French/Swiss border, but not for the Italian/Swiss border. For Switzerland as a whole, prices in congested situations are about five percent higher than hypothetical, non-congested prices.

Contents

1 Introduction

Switzerland is directly interconnected to a significant amount with the German-Austrian, French, and Italian electricity market, which account for more than one third of the European electricity consumption. The need and outcome of investment decisions, and also of policies in Switzerland and its neighbors, thus, require the consideration of current and future market integration. Even though Switzerland is technically ready for market coupling, market integration is still subject to ongoing bilateral negotiations with the European Commission. Although it is clear that integration will be eventually pushed forward, the current degree of integration still has to be analyzed in depth to evaluate the potential effect of alternative energy policies and the impact of unilateral foreign decisions on connected countries.

Our approach in examining the degree of integration is taking advantage of unilateral demand and supply shocks such as the generation from volatile renewable resources, the unavailability of generation units, and national holidays. These exogenous events affect electricity prices in Switzerland and allow estimating the level of market integration by disentangling their effects in situations where electricity prices follow the Law of One Price and where they do not. The Law of One Price (Fetter (1924)) suggests that markets of different regions are fully integrated if an akin good has the same price. Exploiting information on such congested and non-congested situations permits computing but-if prices. That is, we can calculate hypothetical, non-congested Swiss electricity prices in congested situations. By comparing the respective price levels, the congestion-induced surcharge can be assessed. Our measure, thus, evaluates the degree of integration from a policy perspective. It enables policy-makers to learn how the electricity price would react if interconnector capacities were to be increased to abolish congestion situations. Statements are, thereby, possible with respect to all and to specific borders.

This approach is novel compared to previous studies trying to assess electricity market integration by cointegration analyses (Johansen (1988, 1991)).[1] Alike our approach, these studies also rely on testing the assumption of the Law of One Price. However, they neglect modeling demand and supply and solely focus on time series of electricity prices. Our approach, in contrast, explicitly accounts for demand and supply. Thereby, we also account for simultaneity, which traditional system cost-minimizing models fall short of.

We accordingly employ a parametric instrumental-variable estimation to estimate the effect of demand and supply shocks in neighboring countries on Swiss electricity prices in non-/ congested situations. We thereby account for endogeneity of load. Our analysis draws on a rich database comprising hourly data on day-ahead electricity spot prices and its determinants (including exchange-, generation-, consumption-, production-, and outages-related information) regarding Switzerland and neighboring countries from 2015 and 2016.

Based on the congestion-driven price differentials, we find that an expansion of interconnector capacity at the German-Austrian/Swiss border could decrease Swiss electricity prices. In a more attenuated way, the same holds true for the French/Swiss border, but not for the Italian/Swiss border. For Switzerland as a whole, prices in congested situations are about five percent higher than hypothetical non-congested prices.

Furthermore, we employ market fundamentals derived from the estimation of market integration to simulate alternative Swiss policy options. We especially consider changes in Swiss consumption (due

[1] Examples include Balaguer (2011), Böckers and Heimeshoff (2012), Bosco et al. (2010), Bunn and Gianfreda (2010), Karakatsani and Bunn (2008), Robinson (2007, 2008), or De Menezes and Houllier (2016) applying fractional cointegration analysis.

to an increased deployment of heat pumps and electric vehicles or due to reductions stemming from an electricity tax), an increased Swiss generation from volatile renewables, and a Swiss nuclear phase-out and examine how these policies affect Swiss prices and power plant dispatch. We thereby apply four scenarios: (i) business-as-usual, (ii) a generation mix in neighboring countries according to EU 2020 targets, and an additional load decrease (iii) or increase (iv) in neighboring countries.

Our simulation results indicate that renewable expansion has the greatest impact on prices and leads to an increased deployment of generation technologies located on the lower end of the merit-order. Reducing nuclear generation capacities, in contrast, makes Switzerland more reliant on cross-border exchange. Changes in consumption affect prices as expected and only have a small impact on the Swiss marginal production technology. In all situations, an increase in interconnector capacity could lead to further price decreases.

The paper is organized as follows. The next section describes our approach for assessing market integration. Section 3 gives an overview about our dataset. Our results are presented in the fourth section. In section 5 we explain and show our simulations. The final section concludes.

2 Approach

Studies assessing market integration usually employ cointegration analyses. They thereby examine the speed of mean reversion of wholesale prices towards a common price. However, relying on time series analysis to test the convergence of prices necessitates the underlying series to be non-stationary, which is mostly not the case regarding electricity prices (Boissellau (2004), Karakatsani and Bunn (2008), Knittel and Roberts (2005)). Besides this inherent problem, this approach also neglects demand and supply that determine electricity prices. We, therefore, abstain from conducting cointegration analyses and rather take the approach of Grossi et al. (2015) as starting point. They suggest estimating the influence of unilateral foreign demand and supply shocks on the domestic price distinguished by non-/congested situations.

Whereas this approach explicitly accounts for electricity demand and supply, the derivation of their market integration index seems flawed by an omitted variable bias. They propose estimating two specifications: firstly without controlling for congestion situations on the respective borders, and secondly with controlling for them. However, ignoring one important variable yields biased estimates of the effects of variables that are correlated with the omitted variable. Since their measure of the degree of integration employs the ratio of the estimated impact with and without controlling for congestions, implausible indices might result. We, therefore, propose a novel measure described in the following section.

2.1 Measuring market integration

Based on the approach of Grossi et al. (2015), we make use of the different influence which unilateral demand and supply shocks in neighboring countries have on the Swiss electricity price depending on whether cross-border congestions are present or not. In contrast to them, we do not consider these situations separately but rather estimate the influence in a single regression framework. Hence, we can obtain unbiased effects in both situations.

In particular, congestion situations are presumed whenever price differences between two interconnected countries do not follow the Law of One Price. In fact, any price differential greater than zero would suggest that markets are not fully integrated. In our main analysis, we, however, assume a congestion situation if the price differential between two countries is greater than one €/MWh in order to account for, e.g., expectation errors of electricity traders.[2] Dummy variables indicating the existence of congestions are accordingly employed in our estimation and interacted with foreign demand and supply shocks. We use the generation from volatile renewable resources, the unavailability of generation units, and national holidays as unilateral demand and supply shocks that are exogenous to Switzerland. While the outage of power plants acts as a supply side shifter, the increase in generation from renewables shifts residual demand to the left. Public holidays affect the whole demand.

Such estimation then yields coefficients depicting the different influence of these exogenous shocks on the Swiss electricity price in the respective congestion situations. Using this information allows to calculate but-if prices. That is, we can compute hypothetical, non-congested Swiss electricity prices by imputing the shocks' influence in non-congestion situations to the shocks' actual realizations in congested situations. These but-if prices can then be compared to actual prices in congested, in non-congested, or in both situations. Figure 1 illustrates the idea. The upper diagram plots regression lines considering the marginal influence of renewables on prices while the lower diagram depicts respective price levels.

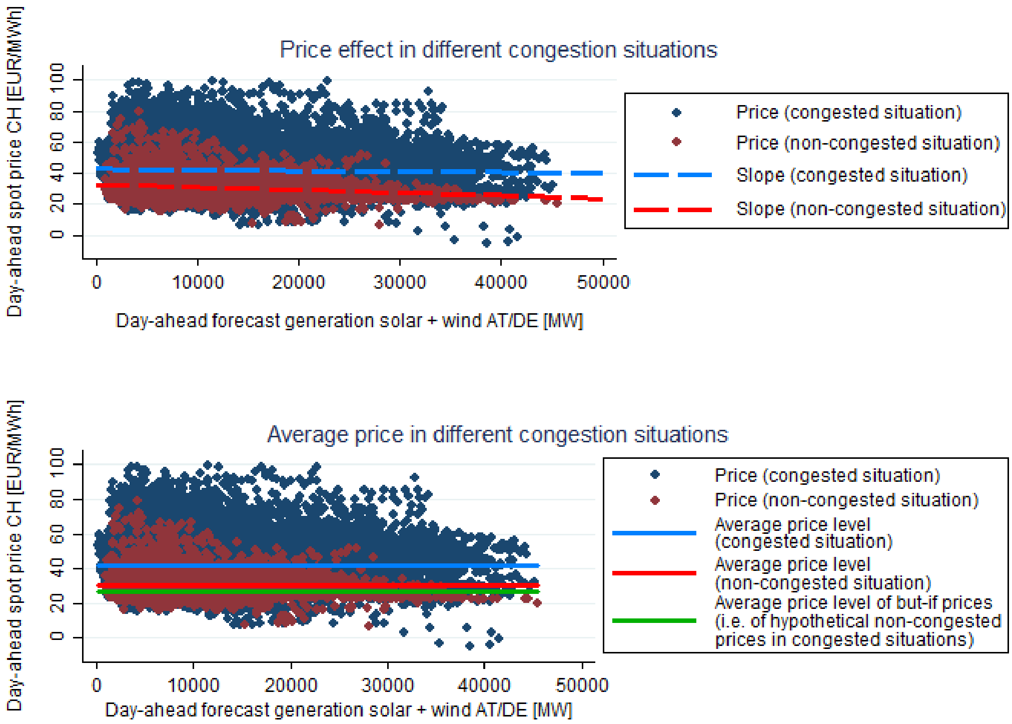

Figure 1: Illustration of but-if prices

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[2] For our sensitivity analyses we also alter this definition. Our market integration results remain largely robust.

In particular, the upper part plots hourly day-ahead Swiss electricity prices against forecasted electricity generation from volatile renewable resources in Germany distinguished by the presence of congestion (blue dots; i.e. price differential greater than one €/MWh) and non-congestion (red dots). It is obvious that German renewables tend to act price-decreasing. Remarkably, this effect seems stronger in non-congested situations as the respective red line is steeper. The lower part replicates the same plot but the blue line now represents the average price level regarding congested situations whereas the red line depicts the average price level in non-congested situations. Obviously, the average electricity price is lower in non-congested situations. The additional green line depicts the average but-if price level. It is derived by imputing the influence of German generation from renewables in non-congested situations (red slope upper part) on the actual realizations in congested situations (blue dots). That is, if congestions were absent, German renewables (in actual congested situations) would have acted as price-decreasing as in non-congested situations. The price level would accordingly have been lower (as the green line is below the blue line in the lower part of Figure 1).

Market integration can be assessed from three different angles giving rise to three different indices. Firstly, actual prices in congested situation can be compared to but-if prices (Index 1). This index indicates the congestion-induced surcharge with respect to congestion situations. Secondly, actual prices in both congested and non-congested situation can be checked against but-if prices (Index 2) thus demonstrating the overall congestion-induced surcharge. Finally, actual prices in non-congested situations can also be compared to but-if prices (Index 3). This index thus shows whether actually congested prices could also undercut the actually non-congested prices if the congestion-induced surcharge was absent.

Such comparisons of price levels allow intuitive conclusions on percentage-markups on prices due to cross-border congestion. In order to gauge integration between two neighboring markets, all foreign shocks on the domestic country should be considered when computing the indices (in contrast to the previous illustration drawing only on renewables for simplification). Assessing overall integration accordingly necessitates considering shocks from all neighboring countries. However, before we depict their computation in detail, we describe our estimation strategy as the respective coefficients build the indices' basis.

2.2 Estimation strategy

We explore the degree of integration by modelling the Swiss electricity price depending on foreign demand and supply shocks while controlling for domestic load and shocks, commodity prices and time-specific effects. Foreign shocks thereby enter distinguished by non-/congestion situation. Technically, we estimate the following equation

$$
\begin{aligned}
P_{CH,t} = {} & \alpha + \beta L_{CH,t} + \delta_1 RE_{CH,t} + \vartheta_1 cap_{unav\,CH,t} + \omega_1 holiday_{CH,t} \\
& + \sum_i \left\langle \begin{matrix} \delta_{2i}^{Cong} RE_{i,t} \times Cong_{i,t} + \delta_{2i}^{NonCong} RE_{i,t} \times NonCong_{i,t} + \\ \vartheta_{2i}^{Cong} cap_{unav\,i,t} \times Cong_{i,t} + \vartheta_{2i}^{NonCong} cap_{unav\,i,t} \times NonCong_{i,t} + \\ \omega_{2i}^{Cong} holiday_{i,t} \times Cong_{i,t} + \omega_{2i}^{NonCong} holiday_{i,t} \times NonCong_{i,t} + \\ \theta_i Cong_{i,t} \end{matrix} \right\rangle + \boldsymbol{X}_t'\varphi + \boldsymbol{Cal}_t'\sigma \\
& + \varepsilon_t,
\end{aligned}
$$

where t depicts the respective hour; $i \in \{AT/DE, FR, IT\}$ indicates the respective neighboring country; α represents the intercept; and ε_t is the idiosyncratic error term. That is, we regress day-ahead Swiss electricity spot prices ($P_{CH,t}$) on Swiss forecasted load ($L_{CH,t}$), Swiss day-ahead forecasts of generation from intermittent renewables ($RE_{CH,t}$), unavailability of Swiss generation units ($cap_{unav_{CH,t}}$), Swiss public holidays ($holiday_{CH,t}$), and a vector of commodity prices[3] ($\boldsymbol{X}_t'$), while accounting for time-specific effects[4] ($\boldsymbol{Cal}_t'$). The respective foreign shocks ($RE_{i,t}$,$cap_{unav_{i,t}}$ and $holiday_{i,t}$) are interacted with a dummy variable ($Cong_{i,t}$)[5] indicating whether a congestion is present on the respective border.

Forecasted load is considered to enter the model as an endogenous variable since the relationship between supply prices and equilibrium quantity may introduce bias due to a possible reverse causality. We thus employ an instrumental variable (IV) technique and estimate the model by the method of two-stage least squares (2SLS) as well as IV-GMM (generalized method of moments).[6] Thereby, we use industrial production as well as temperatures and their squares as excluded instruments.[7]

2.3 Computation of indices

Our indices measure market integration from three different perspectives. They relate the average level of actual prices in congested situations (ι_i^{Cong}), the average level of actual prices in both congested and non-congested situations (ι_i^{mean}), and the average level of actual prices in non-congested situations ($\iota_i^{NonCong}$) to the average level of but-if prices ($\iota_i^{NonCong\_imputed}$), respectively:

$$I_i^1 = \frac{\iota_i^{Cong}}{\iota_i^{NonCong\_imputed}}, \qquad I_i^2 = \frac{\iota_i^{mean}}{\iota_i^{NonCong\_imputed}}, \qquad I_i^3 = \frac{\iota_i^{NonCong}}{\iota_i^{NonCong\_imputed}}.$$

These indices initially focus on individual borders depicted by i. Overall indices are accordingly computed with respect to all neighboring countries simultaneously. The common denominator serving as reference is derived by imputing the coefficients of the foreign shocks in non-congested situations on the shocks' actual realizations in congested situations. We subsequently take the mean of these hypothetical values and add the intercept value:

$$\iota_i^{NonCong\_imputed} = \frac{1}{T}\sum_{t=1}^{T}\left[\hat{\alpha} + \left\langle \begin{matrix} \hat{\delta}_{2i}^{NonCong} RE_{i,t} \times Cong_{i,t} + \\ \hat{\vartheta}_{2i}^{NonCong} cap_{unav_{i,t}} \times Cong_{i,t} + \\ \hat{\omega}_{2i}^{NonCong} holiday_{i,t} \times Cong_{i,t} \end{matrix} \right\rangle\right].$$

Disregarding the effects of other variables enables a clear *ceteris paribus* interpretation stemming from the independent coefficients. The respective price levels in the numerators are calculated in the following manner also using the coefficients of our regression equation:

[3] That is, coal, gas, and oil prices – as long as they are required by the generating technology in the combined (i.e. cross-border-exchange adjusted) Swiss merit-order.
[4] That is, we employ dummy variables for hours, days, and months.
[5] Note that $NonCong_{i,t} = I(Cong_{i,t} = 0)$ for better representation.
[6] In contrast to Grossi et al. (2015) who engage in semi-parametric estimation using the partially linear Robinson (1998) double residual estimator combined with a control function approach alike Blundell and Powell (2004), we abstain from modelling the supply curve in a more flexible way since the relationship between Swiss electricity prices and load does not turn out to be nonlinear.
[7] Temperature acts as an instrument because higher temperatures increase electricity demand through the need for cooling, while lower temperatures require more electricity for heating. The squared term is included to account for a possible nonlinear relation.

$$\iota_i^{Cong} = \frac{1}{T}\sum_{t=1}^{T}\left[\hat{\alpha} + \left\langle\begin{matrix} \hat{\delta}_{2i}^{Cong} RE_{i,t} \times Cong_{i,t} + \\ \hat{\vartheta}_{2i}^{Cong} cap_{unav_{i,t}} \times Cong_{i,t} + \\ \hat{\omega}_{2i}^{Cong} holiday_{i,t} \times Cong_{i,t} + \\ \hat{\theta}_i Cong_{i,t} \end{matrix}\right\rangle\right],$$

$$\iota_i^{mean} = \frac{1}{T}\sum_{t=1}^{T}\left[\hat{\alpha} + \left\langle\begin{matrix} \hat{\delta}_{2i}^{Cong} RE_{i,t} \times Cong_{i,t} + \hat{\delta}_{2i}^{NonCong} RE_{i,t} \times NonCong_{i,t} + \\ \hat{\vartheta}_{2i}^{Cong} cap_{unav_{i,t}} \times Cong_{i,t} + \hat{\vartheta}_{2i}^{NonCong} cap_{unav_{i,t}} \times NonCong_{i,t} + \\ \hat{\omega}_{2i}^{Cong} holiday_{i,t} \times Cong_{i,t} + \hat{\omega}_{2i}^{NonCong} holiday_{i,t} \times NonCong_{i,t} + \\ \hat{\theta}_i Cong_{i,t} \end{matrix}\right\rangle\right],$$

$$\iota_i^{NonCong} = \frac{1}{T}\sum_{t=1}^{T}\left[\hat{\alpha} + \left\langle\begin{matrix} \hat{\delta}_{2i}^{NonCong} RE_{i,t} \times NonCong_{i,t} + \\ \hat{\vartheta}_{2i}^{NonCong} cap_{unav_{i,t}} \times NonCong_{i,t} + \\ \hat{\omega}_{2i}^{NonCong} holiday_{i,t} \times NonCong_{i,t} \end{matrix}\right\rangle\right].$$

3 Data and setting

The Swiss electricity market is interconnected to France, Italy (i.e. the bidding zone of North Italy) as well as Germany and Austria, which together form the German-Austrian bidding zone. The respective interconnector capacities at the German-Austrian/Swiss border amount to up to 5.2 GW for Swiss exports and 3.2 GW for Swiss imports (measured by day-ahead net transfer capacity (NTC)). For France, these numbers correspond to 1.4 GW and 3.2 GW; and for Italy 4.5 GW and 1.9 GW for Swiss exports and imports, respectively. (Note that Swiss peak demand reaches up to 10 GW.) The degree of capacity utilization is depicted in Figure A-1 in the annex. Day-ahead available transfer capacity (ATC) is allocated by means of explicit auctions on all borders since Switzerland is not part of the European internal electricity market. That is, despite being technically and operationally ready for market coupling, political agreements have not been achieved between Switzerland and the European Commission by now.

Explicit auctions entail that capacities and electricity are traded on two separate markets. Thereby, trading in capacities takes place before electricity and is coordinated by the Joint Allocation Office (JAO). In coupled markets capacities are, in contrast, allocated through implicit auctions implying that cross-border capacities are bundled on the spot energy exchange. Supply and demand for electricity in two neighboring countries are balanced until the respective price differential is zero or until available capacity is exhausted. This removes uncertainty caused by the temporal separation of markets and improves the usage of capacities (Pellini (2012)). For our analysis, it is negligible whether price differences are caused by an implicit or explicit allocation of capacities. As price differences can also arise with respect to implicit allocations if capacities are exhausted, they are still indicative of less integrated markets and indices can be calculated in the described manner. The introduction of implicit allocations could, however, greatly decrease the share of congested hours through a more efficient usage of capacity.

Our dataset comprises information on electricity prices and its determinants regarding Switzerland and neighboring countries for the years 2015 and 2016. Most data is available at the transparency platform of ENTSO-E (2017). Table 1 presents summary statistics and also mentions alternative sources.

First of all, we employ hourly day-ahead spot prices for electricity in the respective bidding zones. Obviously, (North) Italy has the highest (49 EUR/MWh) and Germany/Austria the lowest average price (32 EUR/MWh). Swiss and French prices are arranged in between. Figure A-2 in the annex plots prices over time. France encounters a remarkable maximum of more than 800 euro which is due to huge residual loads and unusually low nuclear-power-plant availability in November 2016. In contrast, negative prices can be observed in the German-Austrian bidding zone caused by low demand and high power generation from volatile wind and solar energy.

Regarding the determinants of the Swiss electricity price, we use day-ahead forecasts of Swiss load. Thereby, we employ industrial production and temperature in Switzerland as instruments for load to circumvent the simultaneity of load and price in our analysis. Further determinants are demand and supply shifters in Switzerland and the neighboring electricity markets. We utilize day-ahead forecast of generation from volatile wind and solar energy, unavailable generation capacity and holidays. Obviously, (intermittent) renewable electricity generation is highest in Germany/Austria with an hourly average of 14 GW while the Swiss average is only 45 MW (FR: 3 GW, IT: 0.8 GW). Figure A-3 in the annex presents the time series in a graphical way.

The unavailable generation capacity concerns all planned outages of (non-intermittent) generation units in an aggregated way. We do not employ data on unplanned outages as Italian data is not available. Yet, with a focus on day-ahead spot prices and forecasted load such within-day shocks are dispensable. All countries encounter times where all generation units are available but, on average, many GW of capacity are unavailable. France and Germany/Austria have – clearly size-contingent – the highest means (28 and 27 GW, respectively) and Switzerland the lowest average (2.3 GW). Figure A-4 in the annex plots unavailability over time.

Public holidays act as demand shifters but only concern a minority of hours in our sample. While about 4 percent of the total hours of 2015 and 2016 are related to Swiss holidays, the percentage in the other countries is lower. This is due to our definition of counting holidays in neighboring countries only as shocks if these holidays do not coincident with a Swiss holiday.

Furthermore, we employ a variable that indicates the presence of a congestion at the specific country borders. We presume a congestion situation in a particular hour if the difference in electricity prices of two neighboring bidding zones is greater than one €/MWh. That is, by focusing on commercial flows we borrow our definition from the Law of One Price. Any deviation from a common price is thus suggestive of less integrated markets.[8] Figure 2 plots the share of congestion situations over time for each Swiss border. For each day of the years 2015 and 2016 a red bar depicts the share of congested hours while the complementing blue bar represents the non-congested hours. Regarding the summer months, less congestion is present at the German-Austrian and at the French border. The French border is, thereby, on average less congested with only 79 percent of total hours (AT/DE: 84%). The Italian border shows a somewhat different picture. While also about 85 percent of total hours are congested, less congestion is obvious regarding winter months. This is in line with the fact, that while

[8] A focus on physical flows would, in contrast, imply that congestions only arise if interconnector capacity is technically exhausted. However, this ignores that the interconnector itself (or more accurately: congestion-management through interconnectors between two disjoint bidding zones) is the reason for congestions as it introduces a friction into cross-border trade. Traders of two neighboring countries cannot behave as if they were in a single market and have to respect limited exchange possibilities, which – in a setting of explicit auctions – have to be purchased before trading. This gives rise to expectation errors so that prices can also diverge even though the interconnector is not exhausted. Furthermore, the physical necessities of electricity transport might counteract commercial trading. This study though is mainly devoted to the analysis of commercial activities. Although we cannot observe the counterfactual of fully integrated markets, focusing on situations in which prices are almost identical (i.e. respecting an error margin of 1 €/MWh (and alternative values in our sensitivity analyses)) allows to draw conclusions from situations that at least come close to this.

Switzerland is a net exporter of electricity to Italy, more congestion is accordingly caused by reduced transfer capacity in the summer months (see also Figure A-1 in the annex). In our empirical part, we also conduct sensitivity analyses to check robustness with respect to different definitions of price differences.

Finally, commodity prices are also accounted for in our analysis. Table 1 shows that crude oil is on average more expensive than natural gas and hard coal (see also Figure A-5 in the annex for a temporal development). In our regression, these input prices are only considered as determining the Swiss electricity price if the respective generation technologies are employed in the neighboring countries and if Switzerland imports electricity from the countries in the respective hours. For this, we construct merit-orders for every country in every hour using the commodity prices and available generation capacity[9] while accounting for net exports to other neighboring countries. These country merit-orders are also important for our subsequent simulations.[10] Figure A-6 in the annex plots merit-orders for the four countries using installed capacities in 2016. Obviously, the German-Austrian bidding zone has the largest generation capacity. France is heavy reliant on nuclear and Italy (North) on natural gas. Swiss capacity amounts to only one-tenth of German-Austrian capacity with the most important generation technology being hydro-related followed by nuclear.

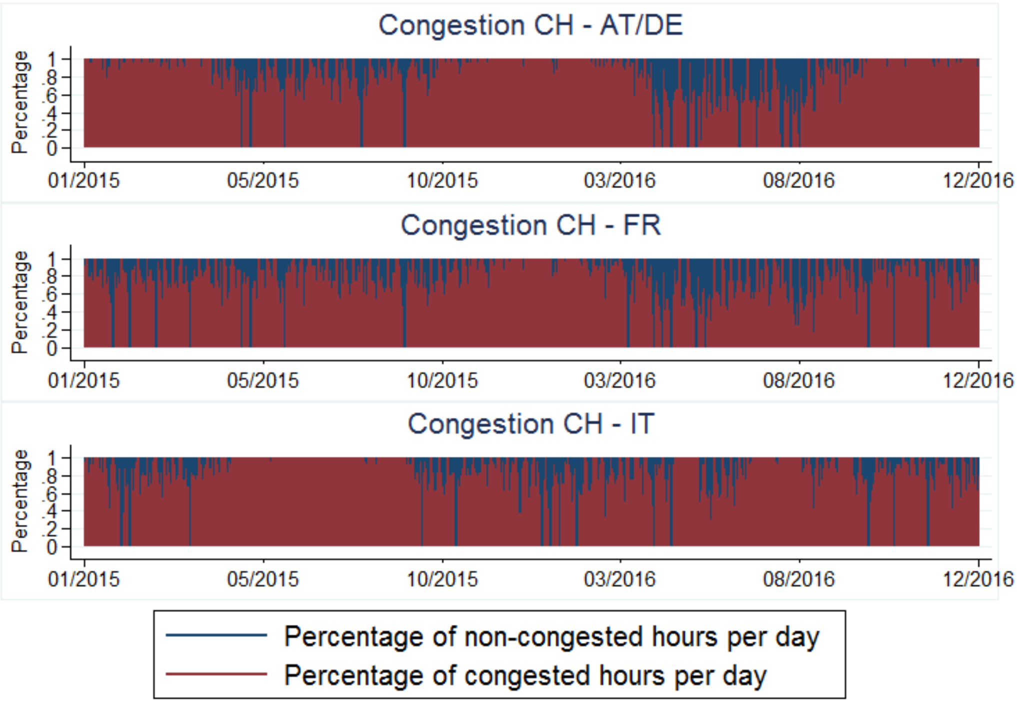

Figure 2: Congestion situations by Swiss border (congestion ≡ price differential > 1 €/MWh)

[9] Regarding hydro-related generation (i.e. run-of-river and poundage, water reservoir, and pumped storage) we do not consider available capacity but rather refer to actual generation. Hydro-related generation is placed low in the merit-order using average productions costs derived by Filippini and Geissmann (2014).

[10] Employing actual generation of water pumped storage means that we abstract from modeling profit-maximization behavior conditional on reservoir fullness. While this does not affect our analysis of market integration, it implies that our simulation studies do not take into account any changes in pump storage due to altered prices. However, our simulation studies are explicitly meant as ceteris-paribus analyses that take the generation mix as given.

Table 1: Summary statistics (all hours in 2015/2016) (continued on next page)

Variable	Mean	Std. Dev.	Min	Max	Unit, resolution	Source, notes
Electricity prices						
CH day-ahead spot price	40.94	13.90	-5.45	120.90	EUR/MWh, hourly	ENTSO-E (2017)
AT/DE day-ahead spot price	31.56	10.93	-67.09	104.96	EUR/MWh, hourly	ENTSO-E (2017)
FR day-ahead spot price	40.00	18.62	1.70	874.01	EUR/MWh, hourly	ENTSO-E (2017)
IT day-ahead spot price	48.72	14.86	10.00	150.00	EUR/MWh, hourly	ENTSO-E (2017), bidding zone IT north
Variables CH						
CH load forecast	7040.08	1025.54	4836.48	10653.47	MW, hourly	ENTSO-E (2017)
CH temperature	10.44	7.62	-7.80	33.50	°C, hourly	wunderground.com, country average
CH industrial production	105.75	1.59	103.50	108.70	Index, quarterly	Swiss Federal Statistical Office (2010=100)
Day-ahead renewables generation forecast	45.16	58.01	0.02	337.64	MW, hourly	ENTSO-E (2017), wind and solar
Unavailable generation capacity	2359.82	1154.35	0.00	8598.00	MW, hourly	ENTSO-E (2017)
Holiday	0.04	0.19	0.00	1.00	Dummy, daily	Own research
Shocks AT/DE						
Day-ahead renewables generation forecast	14049.65	8873.78	657.01	45493.84	MW, hourly	ENTSO-E (2017), wind and solar
Unavailable generation capacity	27122.41	10038.89	0.00	55065.50	MW, hourly	ENTSO-E (2017)
Holiday	0.01	0.10	0.00	1.00	Dummy, daily	Own research (if not a holiday in CH)
Shocks FR						
Day-ahead renewables generation forecast	3082.54	1770.68	280.23	10973.49	MW, hourly	ENTSO-E (2017), wind and solar
Unavailable generation capacity	28313.18	12646.86	0.00	59798.40	MW, hourly	ENTSO-E (2017)
Holiday	0.01	0.12	0.00	1.00	Dummy, daily	Own research (if not a holiday in CH)
Shocks IT						
Day-ahead renewables generation forecast	831.74	1233.29	0.00	5507.00	MW, hourly	ENTSO-E (2017), bidding zone IT north, wind and solar
Unavailable generation capacity	6425.55	4068.20	0.00	17886.00	MW, hourly	ENTSO-E (2017), bidding zone IT north
Holiday	0.01	0.10	0.00	1.00	Dummy, daily	Own research (if not a holiday in CH)

Table 1: Summary statistics (continued)

Variable	Mean	Std. Dev.	Min	Max	Unit, resolution	Source, notes
Congestion						
CH - AT/DE	0.84	0.36	0.00	1.00	Dummy, hourly	Price difference > 1
CH - FR	0.79	0.41	0.00	1.00	Dummy, hourly	Price difference > 1
CH - IT	0.85	0.35	0.00	1.00	Dummy, hourly	Price difference > 1
Commodity prices						
Hard coal	6.45	1.36	4.67	10.80	EUR/MWh, daily	Datastream (2017): EEX-COAL ARA Future
Natural gas	16.93	3.61	10.60	24.02	EUR/MWh, daily	EEX: TTF Daily Reference Price
Crude oil	32.78	5.88	17.34	46.56	EUR/MWh, daily	Datastream (2017): Crude Oil-Brent

Observations: 17544 hours, i.e. years 2015 and 2016

4 Results

In this section we describe our estimation results, the respective indices measuring market integration, and provide robustness checks.

4.1 Estimation results

Table 2 presents the results of our estimation using the method of two-stage least squares (2SLS) as well as IV-GMM. The F-statistic of the first-stage regression exceeds the weak ID critical values from Stock-Yogo suggesting that load is identified by the instruments (industrial production, temperature and temperature squares). All variables show expected signs. Higher demand in Switzerland in terms of higher load increases the Swiss electricity price (i.e. an increase in Swiss load by 1 MW raises the electricity price by about 0.02 euro). An increased generation from volatile wind and solar energy acts price-decreasing while more unavailable generation capacity leads to a price increase. The presence of a public holiday in Switzerland also reduces the electricity price through a decreased demand. However, this effect is not statistically significant in contrast to the previously mentioned variables.

Before turning to the effects of foreign shocks, we comment on the congestion dummies themselves. Regarding the German-Austrian and French border, prices in congestion situations are, on average, about 5 and 3 euro higher than in non-congested situations, respectively. Congestions on the Italian border only amount to an increase of about 0.5 euro, which is, however, statistically insignificant. Increased generation from volatile wind and solar energy in the German-Austrian bidding zone significantly decreases the Swiss electricity price. The obligatory in-feed thus exports cheap electricity to Switzerland (“merit-order effect”) and thus Swiss prices decrease. Thereby, the influence is more than twice as large in non-congested than in congested situations. Unavailable German generation capacity acts price-increasing, which is intuitive as less conventional, German generation capacity is compensated by more expensive conventional generation capacity being exported to Switzerland. Whenever German-Austrian holidays are present, Swiss prices are higher, which should not be interpreted directly causal. This somehow counter-intuitive relationship can be explained by German holidays being negatively correlated with German renewables production in our sample period: Less German renewables had been available to serve demand, which in turn acts like a positive German demand shock increasing Swiss prices. Furthermore, the price-increasing effects of unavailable, German-Austrian generation capacity as well as German-Austrian holidays are also reinforced in congested situations.

Table 2: Estimation results

Dependent variable: CH electricity spot price	**Coefficient**	**Std. Err.**
CH load	0.01655***	(0.00176)
CH renewables generation	-0.03624***	(0.00629)
CH unavailable generation capacity	0.00046**	(0.00021)
CH holiday	-1.94505	(1.38845)
AT/DE renewables generation (congestion)	-0.00013***	(0.00003)
AT/DE renewables generation (no congestion)	-0.00029***	(0.00005)
AT/DE unavailable generation capacity (congestion)	0.00006	(0.00005)
AT/DE unavailable generation capacity (no congestion)	0.00020***	(0.00005)
AT/DE holiday (congestion)	1.27880	(2.33801)
AT/DE holiday (no congestion)	5.93277**	(2.69586)
FR renewables generation (congestion)	-0.00062***	(0.00016)
FR renewables generation (no congestion)	-0.00050**	(0.00022)
FR unavailable generation capacity (congestion)	0.00021***	(0.00005)
FR unavailable generation capacity (no congestion)	0.00029***	(0.00005)
FR holiday (congestion)	-3.67203	(3.64103)
FR holiday (no congestion)	-1.26226	(2.28119)
IT renewables generation (congestion)	-0.00095**	(0.00038)
IT renewables generation (no congestion)	-0.00126**	(0.00050)
IT unavailable generation capacity (congestion)	-0.00042***	(0.00009)
IT unavailable generation capacity (no congestion)	-0.00026**	(0.00012)
IT holiday (congestion)	-1.56986	(1.63666)
IT holiday (no congestion)	-1.23312	(1.94218)
Hard coal price	0.04616***	(0.00986)
Natural gas price	0.06520**	(0.02699)
Crude oil price	-0.01670*	(0.00930)
AT/DE congestion	5.25036***	(1.31059)
FR congestion	3.15133***	(1.18518)
IT congestion	0.53115	(0.88258)
Constant	-79.46498***	(12.25961)
Obs.	15696	
R^2	0.565	
First Stage F-Test (CH load)	270.042	

Notes: 2SLS estimation. The first-stage F-statistic exceeds the weak ID critical values from Stock-Yogo (5%: 13.91) suggesting that load is identified by the instruments. Newey-West standard errors robust to heteroscedasticity and autocorrelation. *,**,***: significant at 10%, 5% and 1% respectively.

While the coefficients of French renewables generation and unavailable generation capacity can be interpreted similarly, the negative sign of French holidays can be explained in the following way. As France is strongly reliant on nuclear generation, a decrease in demand due to a public holiday is unlikely to result in the shutdown of nuclear plants; instead the accordingly still generated, rather cheap electricity is then exported to neighboring countries.

Regarding Italian shocks, increased renewables generation also acts more price-decreasing in non-congested than in congested situations. Concerning the effect of unavailable generation capacity, the sign is, however, reversed so that less available capacity reduces the Swiss price. This observation shows that prices in Switzerland are lower when plant capacity in Italy suffers from greater unavailability. This might be induced by e.g. having low price phases in Italy when plants shut down allowing exporting cheaper electricity to Switzerland. By the same token, exporting from Switzerland to Italy, when there are plant failures in Italy, decreases prices during the inspection period.

Finally regarding the influence of commodity prices, hard coal and natural gas prices exhibit a positive influence on the Swiss electricity price while a higher oil price acts price-decreasing. This corresponds to the intuitive interpretation of an inward shift of the supply curve for the first two variables, whereas the weak negative statistical significance of the oil price stems from only few observations – oil is rarely price setting – and results from coincidence with low price situations, thus rather measures artificial correlation.

4.2 Market integration results

Based on the estimated effects of foreign shocks in non-/congested situations, we derive indices measuring market integration as described in Section 2.3. That is, we compute hypothetical, non-congested Swiss electricity prices by imputing the estimated influence of foreign shocks in non-congestion situations to the shocks' actual realizations in congested situations. The average level of the resulting but-if prices is then compared to actual prices in congested (index 1), in non-congested (index 3), or in both situations (index 2). Table 3 presents the respective results distinguished by border as well as the overall perspective.

Table 3: Integration indices

	Index 1 $\left(\frac{\iota_i^{Cong}}{\iota_i^{NonCong\_imputed}}\right)$	**Index 2** $\left(\frac{\iota_i^{mean}}{\iota_i^{NonCong\_imputed}}\right)$	**Index 3** $\left(\frac{\iota_i^{NonCong}}{\iota_i^{NonCong\_imputed}}\right)$
AT/DE	1.047	1.042	1.019
FR	1.007	1.008	1.014
IT	0.997	0.997	0.999
Overall	1.051	1.050	1.004

Regarding the German-Austrian/Swiss border, we find that both the actual average price levels in congested situations (index 1) as well as the actual overall average price level (regardless of a congestion/non-congestion situation; index 2) are above the level of hypothetical, non-congested Swiss electricity prices in congested situations (‘but-if’), i.e. compared to prices in a situation as if all congestion was relieved. The presence of congestion-induced surcharges implies that reducing congestion on the German-Austrian/Swiss border to zero could yield price reductions in Switzerland. Cheaper German electricity from intermittent renewables being a main driver for congestion, the resulting price level might also be lower than the actual average price level in non-congested situations (as indicated by index 3).

With respect to the French/Swiss border, each index suggests that the average price levels of the different actual prices (in congested situations, in non-congested situations, and in both situations) are above the level of but-if prices in congested situations, but less pronounced than at the German-Austrian/Swiss border. This suggests that removing congestion on the French/Swiss border could also yield price reductions in Switzerland.

Regarding the Italian/Swiss border, we find indices slightly below one. But-if prices are thus slightly above the respective actual price levels and congestion-induced surcharges are not present, which seems to be driven by the fact that Switzerland is generally a net electricity exporter to Italy so that Italian shocks do not retroact to Swiss electricity prices. From a policy perspective, Swiss prices could slightly increase when abolishing congestion on the Italian/Swiss border as more (cheaper) electricity would be exported to Italy. It makes sense to distinguish the indices conditional on Switzerland being net exporter to or net importer from the respective countries. However, before doing so we note that, from an overall perspective, each average price level of actual prices is above the hypothetical price level suggesting that Swiss prices would decrease if any congestion was absent. Electricity prices in congested situations could be cheaper by roughly 5% in Switzerland if congestion was removed. Switzerland is, thus, not fully integrated with its neighboring electricity markets.

Table 4 presents the indices with a distinction conditional on Switzerland being net electricity ex- or importer to the respective countries. It is obvious that in situations where Switzerland exports electricity to the German-Austrian or French bidding zone all indices are lower than in the general case. Index 1 and 2 suggest that removing congestions at the German-Austrian/Swiss border could reduce Swiss prices. The but-if price level would, however, remain above the level of actually non-congested prices (see index 3). There would hardly be any price change at the French/Swiss border indicated by indices being not different from one.

In situations where Switzerland is a net importer, removing congestion would, in contrast, result in reduced Swiss electricity prices at the German-Austrian or French border as all indices are greater than one and also higher than in the general case (Table 3). Regarding Italy, the results in Table 4 are close to identical to the general case for situations where Switzerland net exports electricity to Italy. However, when Switzerland net imports from Italy indices 1 and 2 are still quite similar to the general case and remain below one implying that also in such cases Swiss prices would rather increase if congestion situations were abolished. However, such price increases would still remain below the level of actually non-congested prices as suggested by index 3.

Table 4: Integration indices distinguished by export situation

	Index 1	Index 2	Index 3
When Switzerland net exports to:			
AT/DE	1.020	1.011	0.993
FR	1.000	1.000	1.001
IT	0.997	0.997	0.998
When Switzerland net imports from:			
AT/DE	1.052	1.047	1.017
FR	1.009	1.011	1.018
IT	0.994	0.997	1.007

On more general grounds, these results mirror recent developments of European electricity sector policy. In contrast to the European “Energy Union” goal of free cross-border trade, German unilateral renewable capacity extension led to an enormous growth of cheap short-run variable cost production difficult to export when reaching interconnector capacity limits. Interconnector capacity extension is lagging behind leading to substantial price differences. This is in particular true when cheap renewable electricity could be imported through the German-Austrian interconnectors, but interconnector capacity limits transmission wishes. The power plant mixes in France and Italy, in contrast, changed less dynamically and are still mainly built on dispatchable generation capacity. The differences in price levels are much less dramatic, the national markets are less often decoupled. The three markets remained closer to their long-run stationary equilibrium.

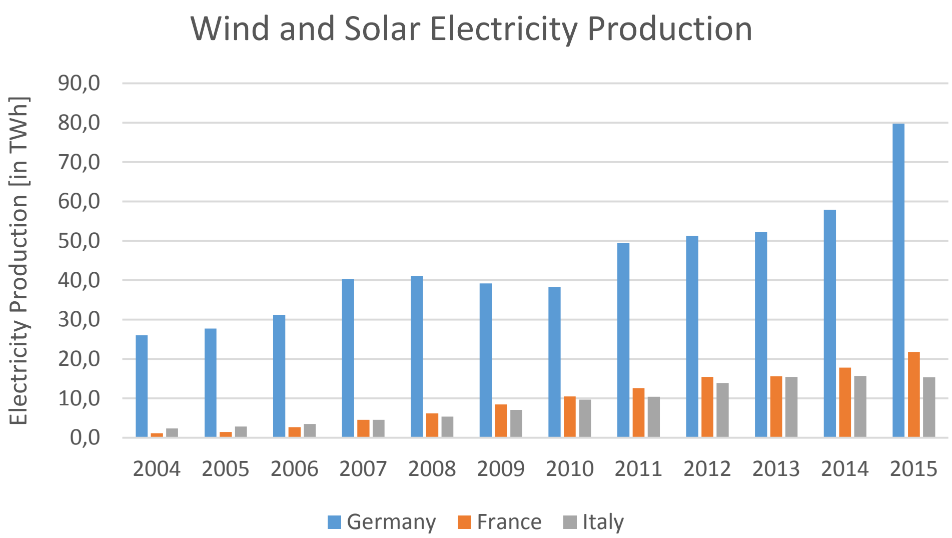

Figure 3: New renewable extension in neighboring countries of Switzerland (source: Eurostat)

The choice of optimal interconnector capacity though depends on the trade-off between the sum of short-run gains from trade and long-run interconnector capacity cost. Thinking about the German-Austrian/Swiss interconnector it will then not be optimal to implement copper plate capacity levels removing all trade price differences: At a certain point long-run marginal cost are simply too high to justify exploiting all potential gains from trade. Therefore, the new renewables' low short-run marginal cost for electricity in Germany will also lead to less market coupling in the long run. Depending on the cost of available interconnector capacity extension projects and the cost-/revenue sharing agreements with neighbors[11], the optimal capacity levels will still have to be determined. This is a complex task, because it includes forecasts on the future sector development comprising power plant investment.

4.3 Sensitivity analysis

We conduct two kinds of sensitivity analyses in order to check the robustness of our results. First of all, we alter the method of estimation. On the one hand, we abstain from accounting for endogeneity of load by means of an alternative ordinary least square (OLS) estimation. On the other hand, we employ a two-step feasible GMM estimation through which efficiency gains might be possible. Our estimation results are depicted Table A-1 in the annex while Table A-2 in the annex contains the respective market integration indices. Regarding OLS results, strong deviations from our IV-regression results are obvious. Hence, failing to account for the simultaneity of price and quantity does not only result in biased estimates but also yields significantly different indices. GMM estimation results, in contrast, are largely comparable to our IV-regression results suggesting that our initial results are robust, which is also reflected in similar indices.

As a second robustness check, we employ different congestion definitions. That is, we no longer assume congestions to be present if the price differential between two neighboring markets is greater than 1 euro. In contrast, we use price differentials of 0.5, 2, 3, 4 or 5 euro. Table A-3 in the annex encloses the respective indices confirming the impression derived from using the initial definition. Regarding the German-Austrian/Swiss and the French/Swiss border as well as with respect to the overall perspective, market integration indices keep their sign but increase in magnitude with higher definitions of price differences. In contrast, regarding the Italian/Swiss border possible gains in terms of price reductions become possible when increasing the definitions of price differences.

5 Simulation

In this section, we simulate alternative Swiss policy options. We give details about our approach and scenarios and subsequently describe our results.

5.1 Approach and scenarios

The simulation of Swiss policy options draws on market fundamentals derived from the previous estimation of market integration. In particular, we employ the estimated effects and realizations of variables included in our IV-regression (Table 2) to analyze Swiss electricity prices while altering respective variables that are affected by policy options and scenarios. Note that our approach entails a ceteris-paribus perspective: When prices are analyzed, everything else is held fixed apart from variables that are captured by the simulated policy options. We thus examine how the respective policies would have affected the actual Swiss electricity prices on average if they had been implemented already in 2015 and 2016. Thereby, any adjustments in the economic conditions and generation mixes are not accounted for; commodity prices and the production from other renewable resources remain as in

[11] This includes the outcome of the political process on market coupling.

2015 and 2016. Interconnector capacity is neither adjusted. Resulting prices are then evaluated in terms of average level, volatility, peak/off-peak spread and are also compared to hypothetical, non-congested prices (like index 2). In addition, we examine how power plant dispatch is affected. For this, we compute the yearly share of production technologies supplying Swiss demand (taking into account cross-border exchange and (hourly) merit-orders in the neighboring countries).

For our simulations we use the following policy options in four different scenarios. Firstly, we investigate the effects of decreasing and increasing Swiss consumption caused by an increased electricity price, or by an increased deployment of heat pumps and electric vehicles, respectively. In particular, a decreased consumption is modeled using demand reductions that would arise if electricity prices were to be increased by 30 or 50 percent in each hour, respectively (i.e. comparable to a value-added electricity tax). For this, we employ hourly price elasticities of demand derived by Bigerna and Bollino (2015). An increased deployment of heat pumps and electric vehicles is modelled by using standard hourly load profiles as deployed by Probst (2014) and SMN (2012). We thereby assume that an increased heat pump deployment leads to a yearly consumption increase of 0.65 TWh[12] while an increased usage of electric vehicles is assumed to increase yearly consumption by 0.5 TWh[13] in Switzerland.

Secondly, we study the impact of increasing Swiss generation from volatile renewables. Simulations are based on an increased yearly generation of 1, 2, 3, and 4 TWh. Thirdly, a potential Swiss nuclear phase-out is simulated. While we also consider full availability of installed capacity as one case, other simulations comprise the stepwise deactivation of most plausible nuclear power plants (i.e. Mühleberg and Beznau) as well as a full deactivation of all plants. Table 5 summarizes the simulated cases.

Table 5: Labels and description of simulation cases

Policy option	Case 1	Case 2	Case 3	Case 4
Load: change in Swiss consumption	**50% 'tax':** reduction in load due to 50% price increase	**30% 'tax':** reduction in load due to 30% price increase	**heat pumps:** increased deployment of heat pumps	**heat pumps + e-vhc.:** increased deployment of heat pumps and electric vehicles
RES expansion: increased Swiss generation from volatile renewables	**1000 GWh:** yearly generation	**2000 GWh:** yearly generation	**3000 GWh:** yearly generation	**4000 GWh:** yearly generation
Nuclear phase-out: deactivation of Swiss nuclear plants	**3333 MW:** full availability of all installed capacity	**2960 MW:** full availability of all installed capacity without plant Mühleberg	**2230 MW:** full availability of all installed capacity without plants Mühleberg and Beznau	**0 MW:** no availability of any nuclear plants

[12] This value is derived using the only available value regarding anticipated heat pump deployment in Germany. Consumption by heat pumps is assumed to amount to 6 TWh in 2030 (i.e. an increase by 2m pumps with an average yearly consumption of 3 MWh; see 50Hertz Transmission GmbH et al. (2017)). The respective share on current German total load is then imputed on the Swiss load leading to about 0.65 TWh.
[13] This value is based on forecasts for 2020 by SFOE (2010).

These policy options are evaluated against the background of different developments in neighboring countries depicted in four different scenarios (summarized in Table 6). The first scenario comprises a business-as-usual assumption in the neighboring countries so that no change in the respective consumption pattern or generation mix is presumed (compared to the actual situation in 2015 and 2016). Secondly, we consider an updated generation mix in the neighboring countries according to EU 2020 targets and individual nuclear/coal phase-out targets.[14] In the third scenario, we additionally presume a load reduction in the neighboring countries besides the updated generation mix. The hourly consumption reductions are derived as above in reaction to an assumed electricity price increase of 30 percent. The final scenario, in contrast, entails a load increase in the neighboring countries due to an increased deployment of both heat pumps and electric vehicles while also assuming the updated generation mix in the neighboring countries. We thereby employ the same load profiles as above while adjusting the yearly consumption increases.[15]

Table 6: Description of simulation scenarios

Scenario	Description
1	No change in consumption pattern and generation mix in neighboring countries
2a	Generation mix in neighboring countries according to EU 2020 targets and individual nuclear/coal phase-out targets
2b	Generation mix in neighboring countries according to EU 2020 targets and individual nuclear/coal phase-out targets; reduction in load due to 30% price increase in neighboring countries
2c	Generation mix in neighboring countries according to EU 2020 targets and individual nuclear/coal phase-out targets; load increase due to an increased deployment of both heat pumps and electric vehicles in neighboring countries

[14] See Table A-4 in the annex for a detailed list.
[15] For Germany/Austria we assume the aforementioned increase of 6 TWh due to heating pumps. For France and Italy, we obtain yearly increases of 4.9 TWh and 1.6 TWh, respectively, using the aforementioned derivation. Load increases due to electric vehicles are based on official German (1m cars) and French (2m cars) 2020 targets. For Italy (North) we assume that yearly consumption increases similarly to Switzerland due to a lack of official statements.

5.2 Simulation results

5.2.1 Scenario 1

In scenario 1, we investigate the effects of Swiss policy options while considering a business-as-usual development in the neighboring countries. Table 7 entails price statistics for alternative load cases while Figure 4 shows respective annual price duration curves. Obviously, rising consumption leads to price increases while decreasing consumption yields lower prices. In particular, load reduction due to a simulated tax that increases the hourly electricity price by 50 percent results in a decrease of the (pre-tax) average price level by 14 percent compared to the base case. An increased deployment of heat pumps and electric vehicles, in contrast, raises the average price – but only to a small extent by 0.5 percent. In a similar vein, load reductions and augmentations deplete and raise standard deviation, volatility and peak/off-peak spread, respectively. Remarkably, the relatively high volatility in case “50% ‘tax’” might be caused by rather strong load reductions in certain hours while in other hours load is not as much reduced so that greater price jumps are imaginable. Table 7 also includes a column depicting the average level of hypothetical, non-congested prices. Compared to the average price level, further price reductions of about 3 euro seem possible if congestion was abolished.

Figure 5 shows the yearly share of production technologies supplying Swiss demand. Note that the base case already indicates the import dependency of Switzerland as lignite, hard coal, and oil together serve as marginal production technology almost every third time even though no such technology is installed in Switzerland. The share of “n.a.” is due to inevitable statistical discrepancies and includes imports to satisfy Swiss demand. Regarding the simulated load cases, a consumption reduction results in a reduced import dependency and increases the share of nuclear generation. Increased consumption, in contrast, reduces the share of nuclear generation (as the cheapest technology to cover demand) while increasing import dependency.

Table 7: Price statistics: load (scenario 1)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	40.032	14.200	0.173	6.002	37.001
50% 'tax'	34.381	13.402	2.655	4.983	31.351
30% 'tax'	36.641	13.707	0.507	5.391	33.611
heat pumps	41.152	14.870	0.156	6.432	38.122
heat pumps + e-vhc.	42.088	15.013	0.147	6.788	39.058

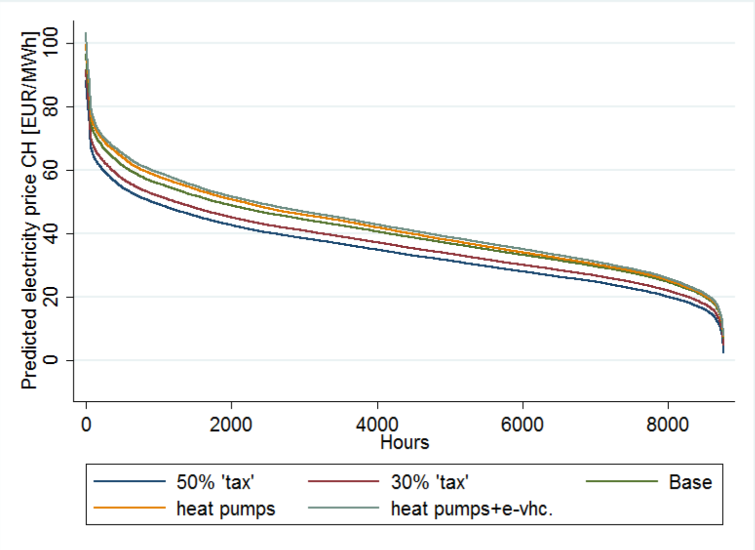

Figure 4: Annual price duration curves: load (scenario 1)

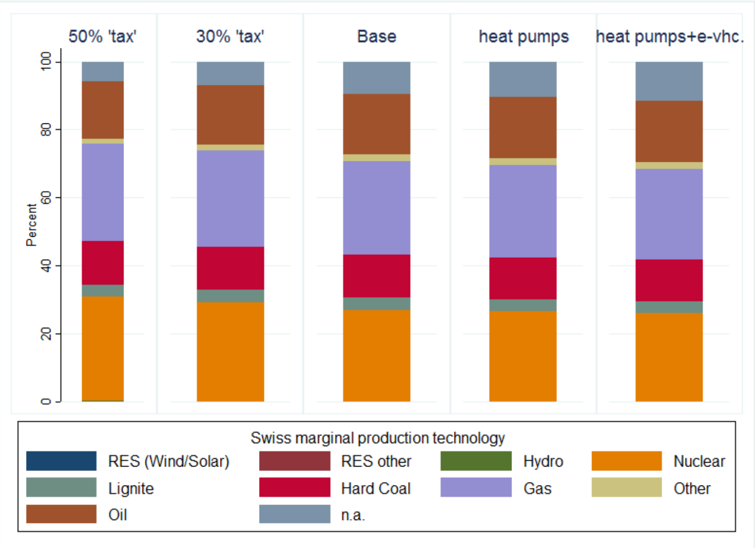

Figure 5: Share of production technology: load (scenario 1)

Regarding an increased generation from volatile renewables in Switzerland, Table 8 comprises the respective price statistics. The average price level is strongly affected and decreases with an increased generation from volatile renewables. Increasing yearly generation up to 4000 GWh (which corresponds to a nine-fold increase of generation in 2016) reduces the average price level by about 35 percent. This result is driven by the estimated, relatively high price-decreasing effect of renewables generation so that the simulated price reductions are indicatively strong. Increasing yearly generation can lead to negative electricity prices.[16] Figure 6 shows that this might even concern up to 800 hours. An increased generation from volatile renewables increases price volatility but reverses the peak/off-peak spread. It also reduces Swiss import dependency while pronouncing the significance of rather cheap generation technologies (Figure 7).

Table 8: Price statistics: RES expansion (scenario 1)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	40.032	14.200	0.173	6.002	37.001
1000 GWh	37.812	14.788	2.486	2.534	30.512
2000 GWh	33.882	16.956	2.317	-3.610	26.582
3000 GWh	29.951	20.143	12.955	-9.754	22.651
4000 GWh	26.021	23.945	7.503	-15.897	18.721

[16] Note that we abstract from modeling profit-maximization behavior of water pumped storage conditional on reservoir fullness. Otherwise there would be fewer negative prices.

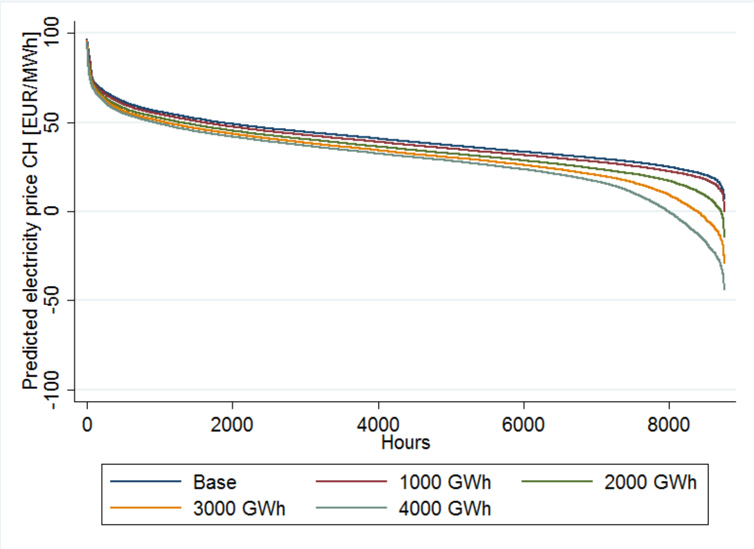

Figure 6: Annual price duration curves: RES expansion (scenario 1)

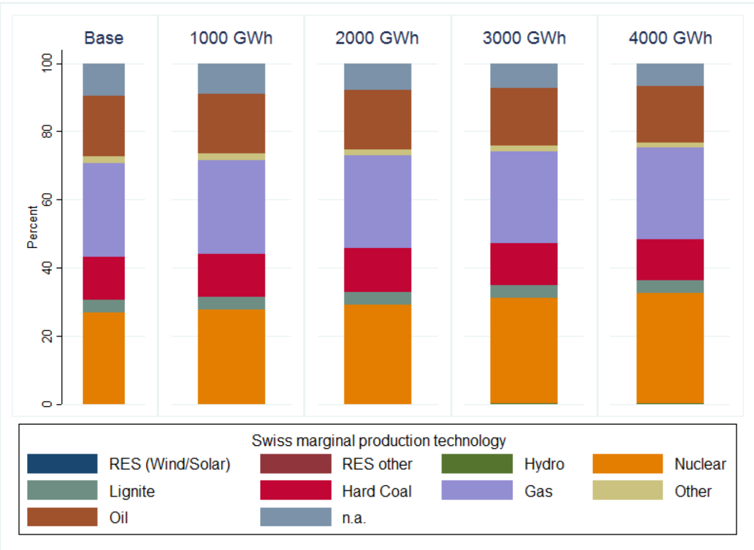

Figure 7: Share of production technology: RES expansion (scenario 1)

Table 9 provides the price statistics with respect to the simulation of a Swiss nuclear phase-out. Price effects are very small. The annual price duration curves depicted in Figure 8 are close to each other. Note that the base case considers actual non-availability. Full availability of all Swiss nuclear power plants (3333 MW) thus leads to a smaller average price. A stepwise reduction of (fully) available capacity increases the average price. This is also reflected in Figure 9 showing the yearly share of production technologies covering Swiss demand. In the case of full availability of nuclear power plants, the share of nuclear increases by 34 percent compared to the base case. It subsequently decreases, however, with less installed nuclear capacity thereby increasing import dependency. In the case of full deactivation, Switzerland becomes strongly dependent on imports. Technologies that are not installed in Switzerland have to be employed in more than 80 percent of cases. This huge increase in import dependency cannot be accounted for in our model representing the reason for only small effects on the average price.

While the standard deviation, volatility and peak/off-peak spread of the simulated electricity prices are also hardly different from the base case, remediating congestion is still resulting in additionally decreased average prices (the same holds true for the simulations of expanded renewables generation).

Table 9: Price statistics: nuclear phase-out (scenario 1)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	40.032	14.200	0.173	6.002	37.001
3333 MW	39.707	14.120	0.191	6.002	32.407
2960 MW	39.874	14.120	0.174	6.002	32.573
2230 MW	40.210	14.120	0.168	6.002	32.910
0 MW	41.227	14.120	0.149	6.002	33.927

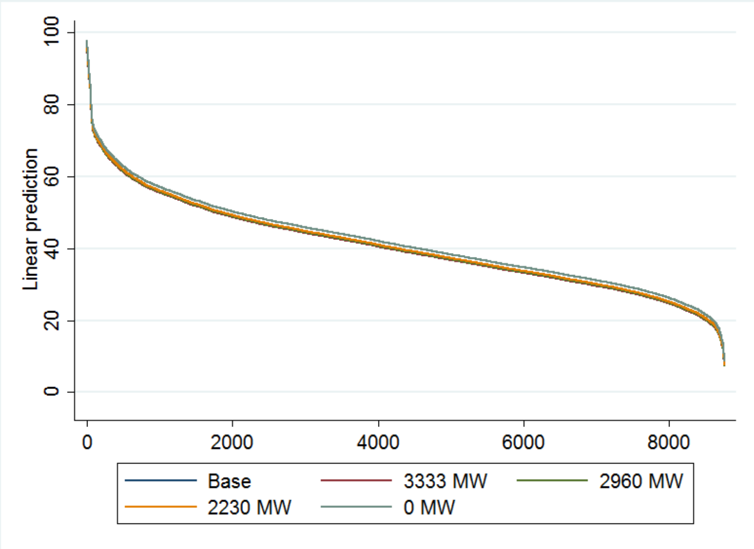

Figure 8: Annual price duration curves: nuclear phase-out (scenario 1)

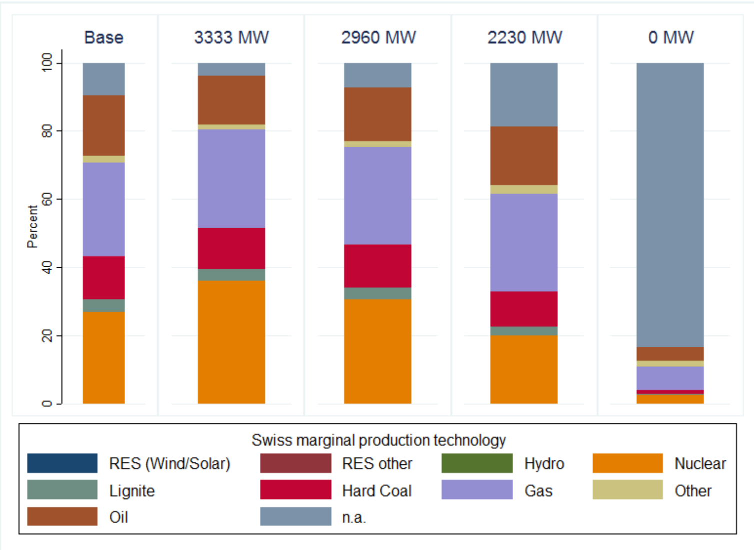

Figure 9: Share of production technology: nuclear phase-out (scenario 1)

5.2.2 Scenario 2a

In scenario 2a, we examine the effects of policy options while adjusting the generation mix in neighboring countries according to EU 2020 targets and individual nuclear/coal phase-out targets. Glancing at the tables and graphs on the following pages (Table 10, Table 11, and Table 12 contain price statistics, while Figure 10, Figure 12, and Figure 14 plot annual price curves and Figure 11, Figure 13, and Figure 15 show Swiss marginal production technologies for load, renewables and nuclear simulations, respectively) reveals that the individual effects of simulated policy cases compared to the respective base cases remain comparable to scenario 1. It accordingly makes sense to investigate more closely how all effects relate to the respective cases in scenario 1.

We especially observe level effects meaning that the average price levels seem to be reduced by about 7 euro in all cases (the same holds true for but-if prices) while standard deviations and volatilities are scaled upwards. The peak/off-peak spread is also reduced and even reverts in all cases. This development seems to be caused mainly by the increased generation from volatile renewables in the neighboring countries. This is also reflected in the yearly shares of production technologies supplying Swiss demand. Due to nuclear and coal phase-outs in the neighboring countries, these technologies accordingly lose shares. In contrast, gas and oil shares increase. Remarkably, however, the share of "n.a." increases strongly. This category mainly contains imports to Switzerland that are not assignable to specific technologies. That is, our model cannot fully model the dispatch in neighboring countries implying that the newly employed technologies also appear in this category. Disentangling changes in shares compared to the respective base cases and to scenario 1 reveals that import dependency increases only marginally and that most of the increase in "n.a." shares is due to an unknown imported technology.[17]

Finally, it is noteworthy that concerning the simulations of increased Swiss generation from volatile renewables more negative hours can be observed in the annual price duration curves. In the highest expansion case an increase of about 700 hours is observable (see Figure 12).

[17] This leaves the interpretation in the previous scenario unaffected. Decreasing "n.a." share also implies a reduced import dependency while strongly increased shares as in the nuclear simulations still depict an increasing import dependency. This is due to the fact that our simulation leaves interconnector capacities untouched implying that "n.a." also absorbs all discrepancy between domestic generation capacity and load in Switzerland.

Table 10: Price statistics: load (scenario 2a)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.547	15.731	1.612	-2.384	30.330
50% 'tax'	27.897	15.147	9.614	-3.404	24.679
30% 'tax'	30.157	15.366	3.728	-2.996	26.940
heat pumps	34.668	16.352	3.894	-1.954	31.450
heat pumps + e-vhc.	35.604	16.559	4.151	-1.599	32.387

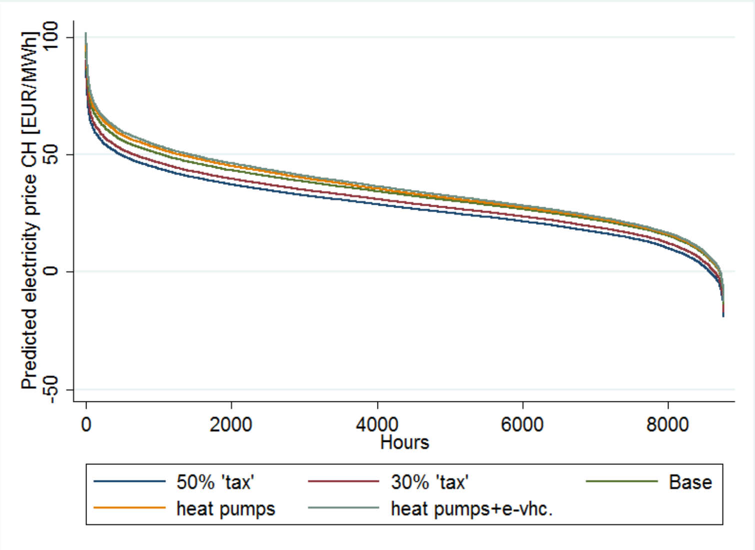

Figure 10: Annual price duration curves: load (scenario 2a)

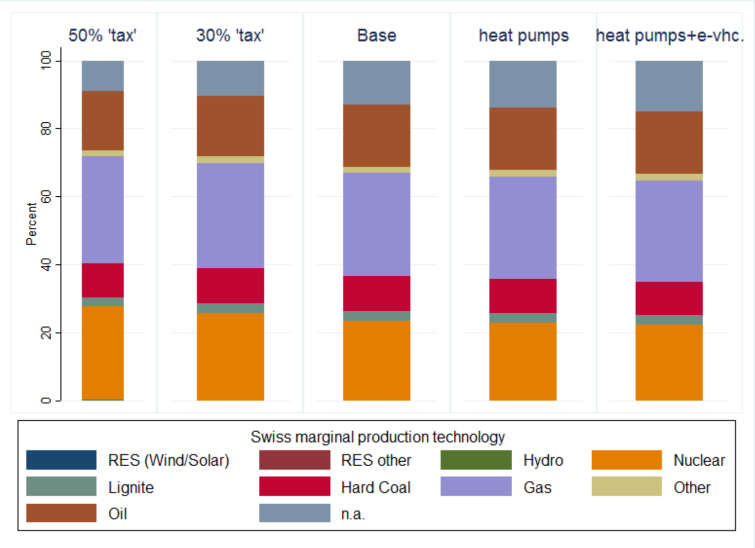

Figure 11: Share of production technology: load (scenario 2a)

Table 11: Price statistics: RES expansion (scenario 2a)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.547	15.731	1.612	-2.384	30.330
1000 GWh	31.328	17.135	4.839	-5.853	28.111
2000 GWh	27.398	20.347	10.018	-11.997	24.180
3000 GWh	23.467	24.162	11.094	-18.140	20.250
4000 GWh	19.537	28.337	13.682	-24.284	16.319

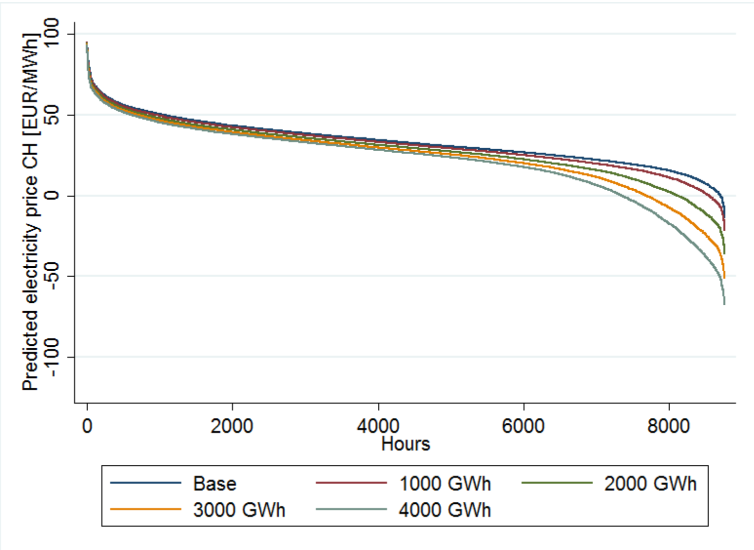

Figure 12: Annual price duration curves: RES expansion (scenario 2a)

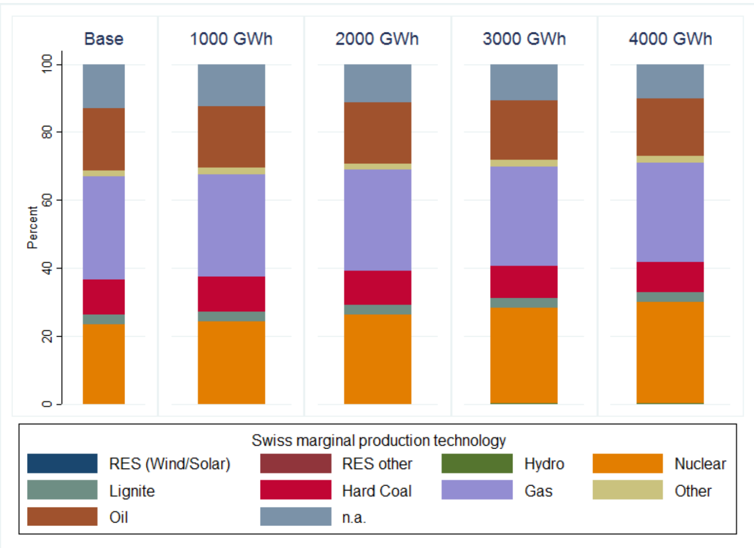

Figure 13: Share of production technology: RES expansion (scenario 2a)

Table 12: Price statistics: nuclear phase-out (scenario 2a)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.547	15.731	1.612	-2.384	30.330
3333 MW	33.223	15.647	3.678	-2.385	30.005
2960 MW	33.389	15.647	1.784	-2.385	30.172
2230 MW	33.726	15.647	1.101	-2.385	30.508
0 MW	34.743	15.647	1.317	-2.385	31.526

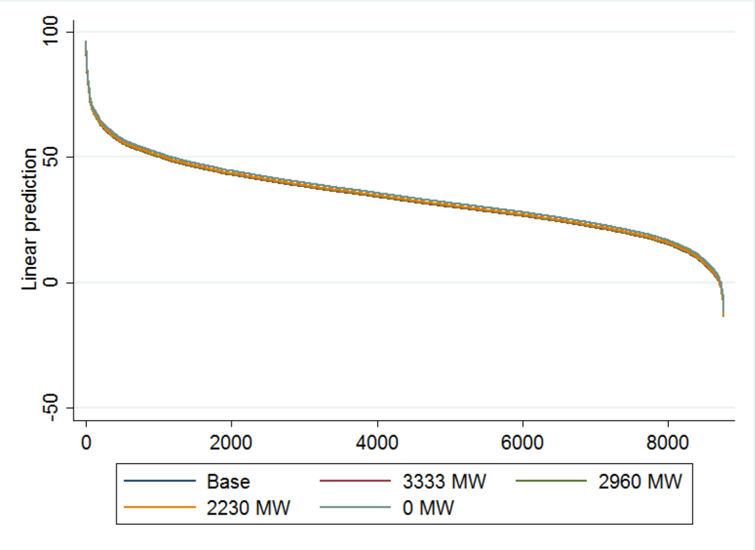

Figure 14: Annual price duration curves: nuclear phase-out (scenario 2a)

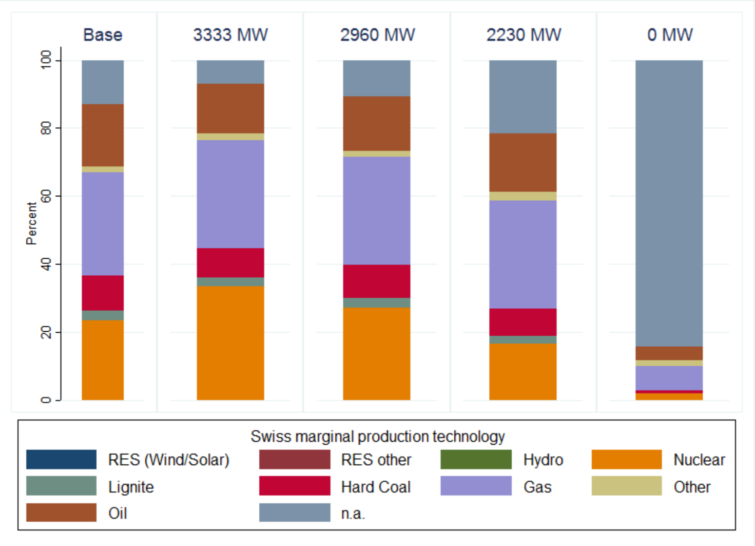

Figure 15: Share of production technology: nuclear phase-out (scenario 2a)

5.2.3 Scenario 2b

In scenario 2b, we study the effects of policy options while both adjusting the generation mix in neighboring countries according to EU 2020 targets and assuming an additional load reduction in these countries. Again, the tables and graphs on the following pages (Table 13, Table 14, and Table 15 contain price statistics, while Figure 16, Figure 18, and Figure 20 plot annual price curves and Figure 17, Figure 19, and Figure 21 show Swiss marginal production technologies for load, renewables and nuclear simulations, respectively) suggest that the individual effects of simulated policy cases compared to the respective base cases are alike scenario 1. We thus abstain from describing them and rather examine more closely how the effects relate to the respective cases in both scenarios 1 and 2a.

While a general reduction in nuclear and coal shares and an increase in gas and “n.a.” could be observed in scenario 2a compared to scenario 1, in scenario 2b the shares of nuclear and coal remain comparable to scenario 1. A strong increase is obvious regarding gas while oil and “n.a.” decrease in importance as technology covering Swiss demand. This suggests that even though the generation mixes in the neighboring countries are altered, the simultaneous load reductions emphasize the export character of foreign nuclear, coal, and especially gas. This is confirmed when focusing on the change of shares from scenario 2a to 2b: the share of nuclear, coal, and gas increases while oil and “n.a.” decrease.

Regarding the price statistics, a similar general price reduction is present as in scenario 2a compared to scenario 1. However, the average price levels are additionally reduced by about 10 percent when comparing scenario 2b and 2a. The reduced consumption in the neighboring countries thus additionally reduces Swiss prices by the import of cheaper generation technologies. However, the respective consumption reductions do not seem to be very influential since Swiss prices are not affected in a greater extent.

Finally, it is to note that the increased amount of hours with negative prices in the highest renewables expansion case observed in scenario 2a is comparable in scenario 2b.

Table 13: Price statistics: load (scenario 2b)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.250	15.717	11.544	-2.408	29.649
50% 'tax'	27.600	15.139	4.184	-3.427	23.998
30% 'tax'	29.860	15.355	2.814	-3.019	26.258
heat pumps	34.371	16.336	9.587	-1.978	30.769
heat pumps + e-vhc.	35.307	16.543	10.060	-1.622	31.705

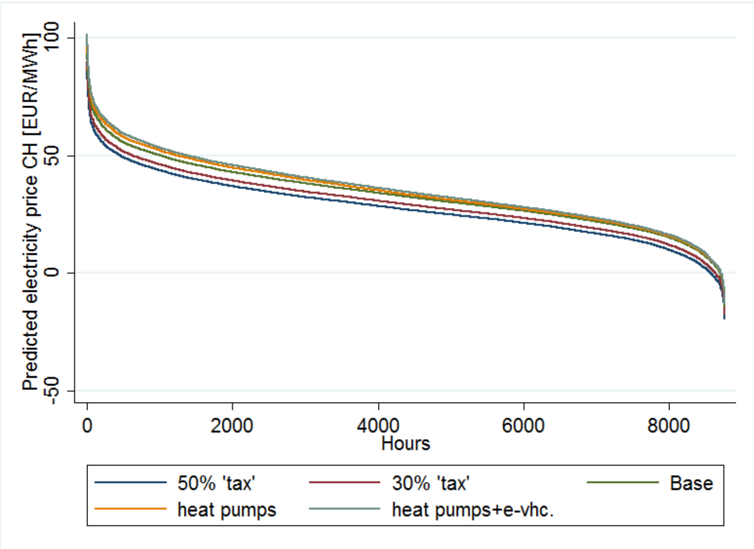

Figure 16: Annual price duration curves: load (scenario 2b)

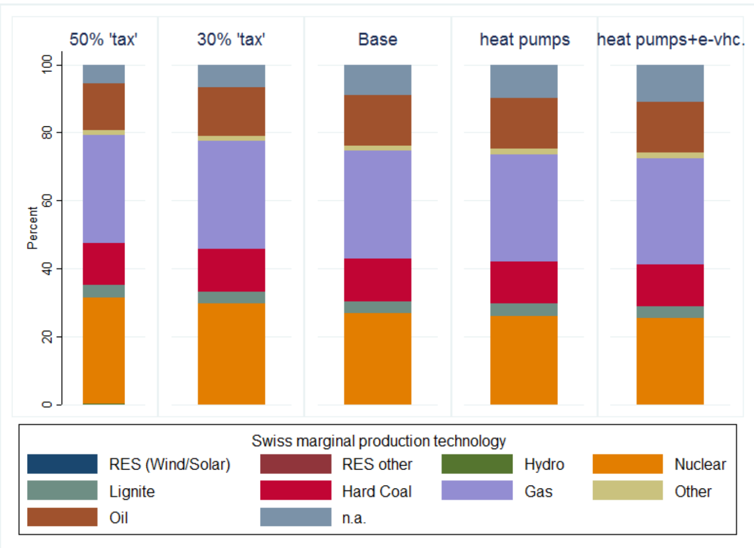

Figure 17: Share of production technology: load (scenario 2b)

Table 14: Price statistics: RES expansion (scenario 2b)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.250	15.717	11.544	-2.408	29.649
1000 GWh	31.031	17.122	3.373	-5.876	27.430
2000 GWh	27.101	20.336	9.255	-12.020	23.499
3000 GWh	23.170	24.152	6.991	-18.163	19.569
4000 GWh	19.240	28.328	9.663	-24.307	15.638

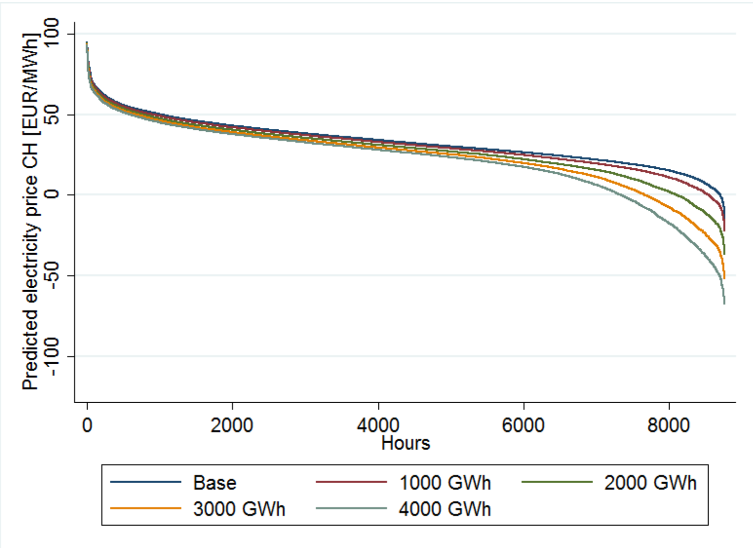

Figure 18: Annual price duration curves: RES expansion (scenario 2b)

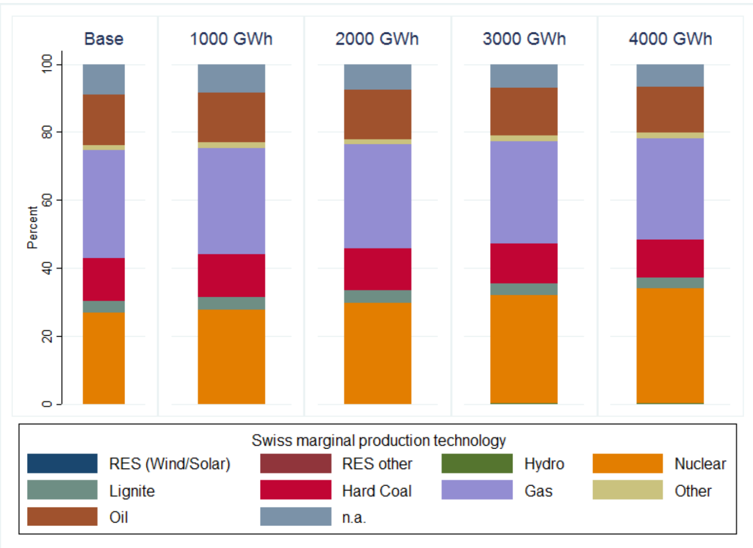

Figure 19: Share of production technology: RES expansion (scenario 2b)

Table 15: Price statistics: nuclear phase-out (scenario 2b)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.250	15.717	11.544	-2.408	29.649
3333 MW	32.926	15.632	6.126	-2.408	29.324
2960 MW	33.092	15.632	4.952	-2.408	29.491
2230 MW	33.429	15.632	3.313	-2.408	29.827
0 MW	34.446	15.632	3.105	-2.408	30.844

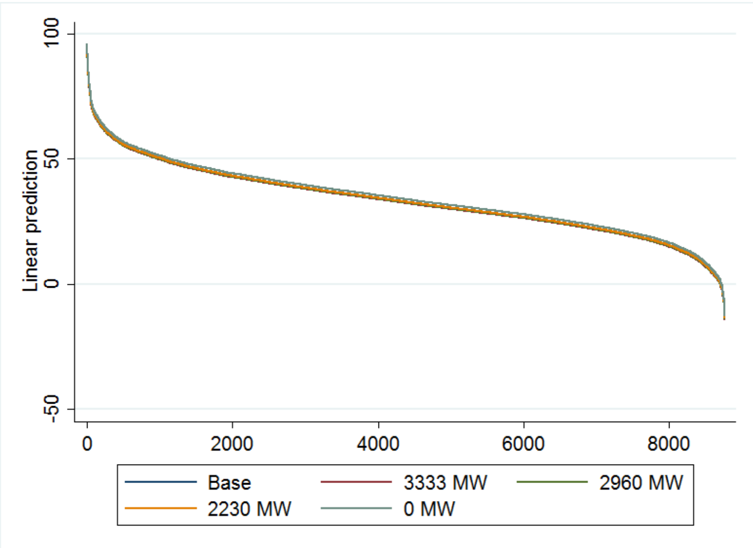

Figure 20: Annual price duration curves: nuclear phase-out (scenario 2b)

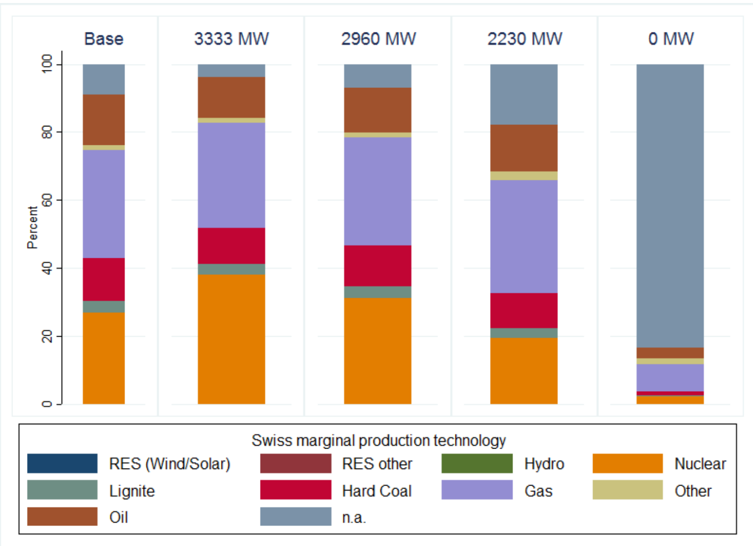

Figure 21: Share of production technology: nuclear phase-out (scenario 2b)

5.2.4 Scenario 2c

In scenario 2c, we examine the effects of policy options while both adjusting the generation mix in neighboring countries according to EU 2020 targets and assuming an additional load increase in these countries. As before, the individual effects of simulated policy cases compared to the respective base cases are alike scenario 1 as indicated by the tables and graphs on the following pages (Table 16, Table 17, and Table 18 contain price statistics, while Figure 22, Figure 24, and Figure 26 plot annual price curves and Figure 23, Figure 25, and Figure 27 show Swiss marginal production technologies for load, renewables and nuclear simulations, respectively). We, therefore, focus again on the relation of effects to the respective cases in both scenarios 1 and 2a.

In scenario 2b, we observe a similar development as in scenario 2a compared to scenario 1: nuclear and coal shares are reduced while shares increase with respect to gas, oil, and “n.a.”. However, these reductions and gains are stronger than from scenario 1 to 2a. This is also confirmed when focusing on the change of shares from scenario 2a to 2b. Hence, the increased consumption in the neighboring countries is supplied domestically implying that the marginal production technology supplying exports to Switzerland cannot be entirely identified.

Regarding the price statistics, a similar general price reduction is also present as in scenario 2a compared to scenario 1. In contrast to scenario 2b, the average price levels are additionally increased by about 6 percent when comparing scenario 2c and 2a. The increased consumption in the neighboring countries thus only marginally affects Swiss prices. Standard deviations, volatilities, and peak/off-peak spread remain comparable to scenario 2a. Abolishing congestion situations also leads to further reductions in the average price level. (The same also applies to scenario 2b).

Table 16: Price statistics: load (scenario 2c)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.741	15.792	1.258	-2.312	30.720
50% 'tax'	28.090	15.205	2.146	-3.331	25.070
30% 'tax'	30.351	15.425	7.525	-2.923	27.330
heat pumps	34.861	16.417	2.002	-1.882	31.841
heat pumps + e-vhc.	35.798	16.629	1.301	-1.526	32.777

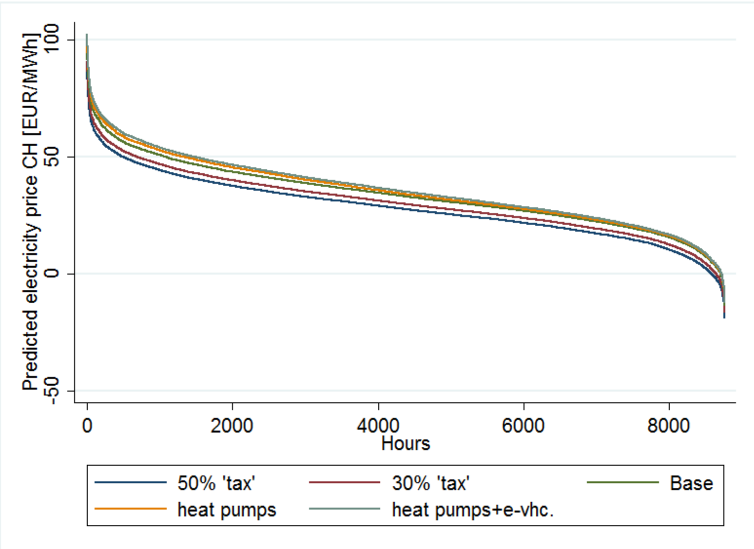

Figure 22: Annual price duration curves: load (scenario 2c)

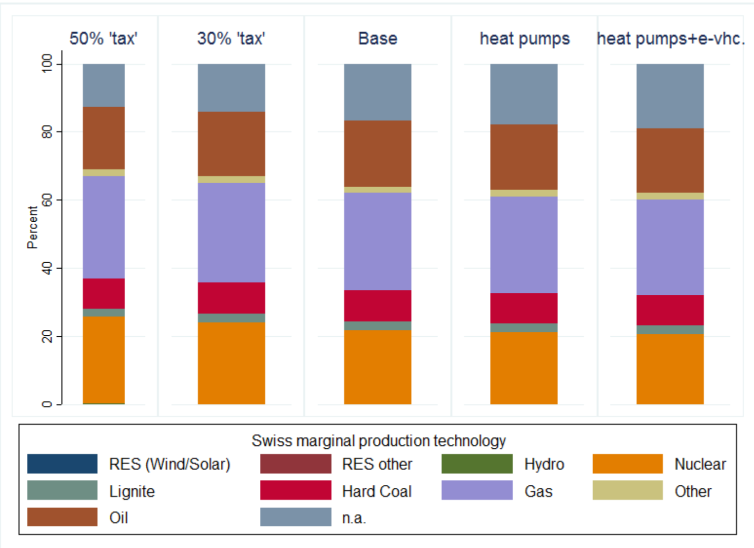

Figure 23: Share of production technology: load (scenario 2c)

Table 17: Price statistics: RES expansion (scenario 2c)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.741	15.792	1.258	-2.312	30.720
1000 GWh	31.522	17.196	5.013	-5.780	28.501
2000 GWh	27.591	20.405	6.997	-11.924	24.571
3000 GWh	23.661	24.217	17.894	-18.068	20.640
4000 GWh	19.730	28.389	10.068	-24.211	16.710

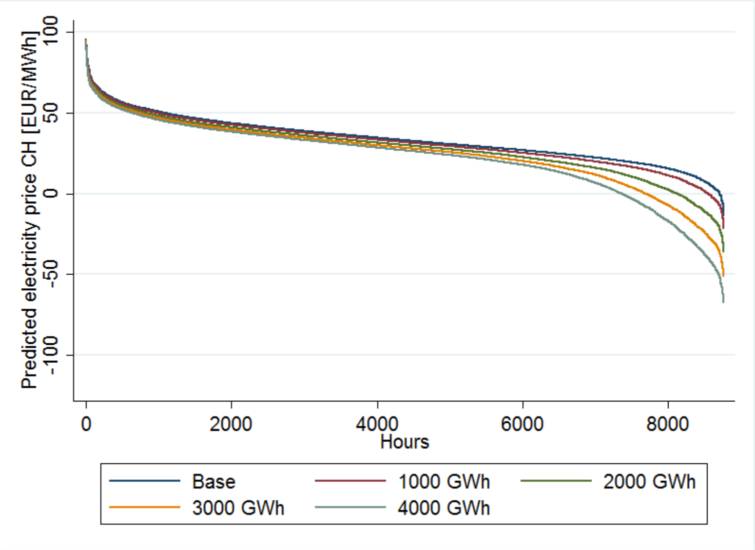

Figure 24: Annual price duration curves: RES expansion (scenario 2c)

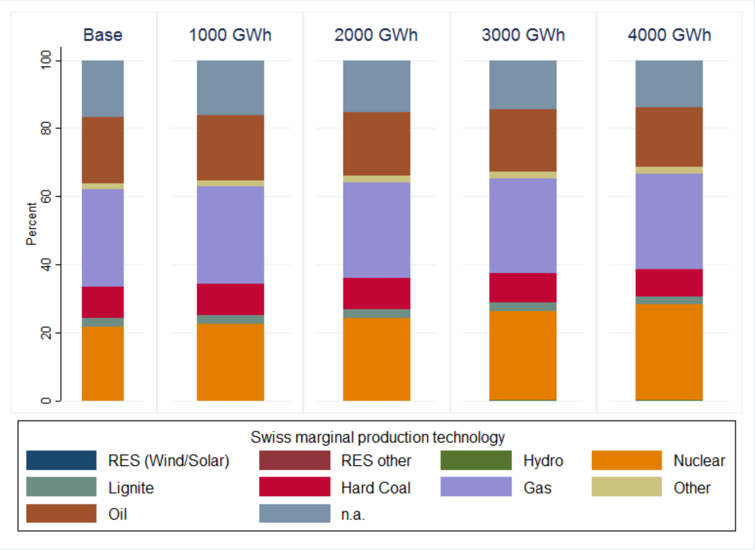

Figure 25: Share of production technology: RES expansion (scenario 2c)

Table 18: Price statistics: nuclear phase-out (scenario 2c)

Simulation case	Average price	Std. Dev.	Volatility	Peak/Off-Peak Spread (Mean)	Average price (no congestion)
Base	33.741	15.792	1.258	-2.312	30.720
3333 MW	33.416	15.708	2.115	-2.312	30.396
2960 MW	33.583	15.708	0.932	-2.312	30.562
2230 MW	33.919	15.708	1.770	-2.312	30.899
0 MW	34.937	15.708	2.072	-2.312	31.916

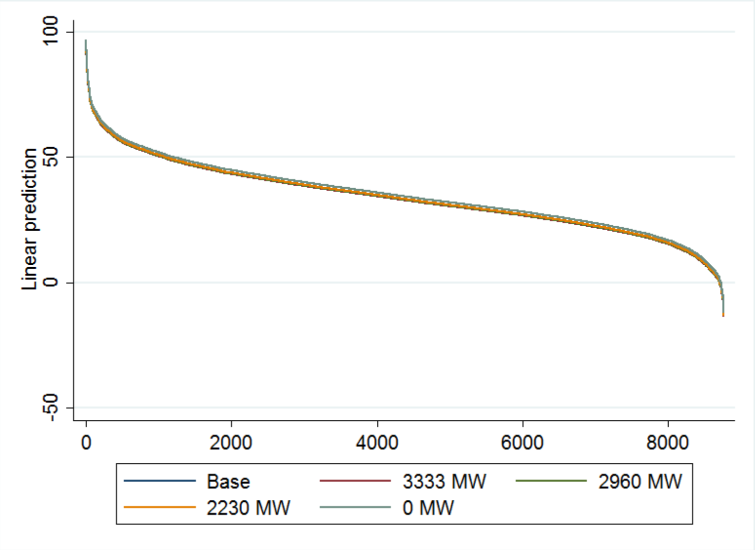

Figure 26: Annual price duration curves: nuclear phase-out (scenario 2c)

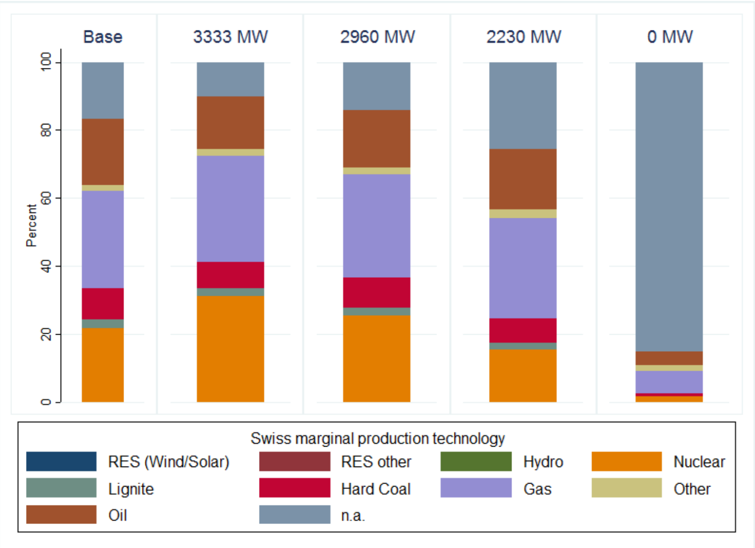

Figure 27: Share of production technology: nuclear phase-out (scenario 2c)

6 Conclusion

In this paper, we have investigated the degree of integration of the Swiss electricity market. Drawing on a novel measure that intuitively describes price reactions that would result from an increase in interconnector capacities meant to abolish congestion situations, we have found that an expansion of interconnector capacity at the German-Austrian/Swiss border could decrease Swiss electricity prices. In a more attenuated way, the same holds true for the French/Swiss border, but not for the Italian/Swiss border. For Switzerland as a whole, prices in congested situations are about five percent higher than hypothetical non-congested prices.

Complementary simulations that employ market fundamentals derived from the estimation of market integration suggest that renewable expansion in Switzerland has the greatest impact on Swiss electricity prices and leads to an increased deployment of generation technologies located on the lower end of merit-order. Reducing Swiss nuclear generation capacities, in contrast, makes Switzerland more reliant on cross-border exchange. Changes in consumption affect prices as expected and only have a small impact on the Swiss marginal production technology. In all situations, an increase in interconnector capacity could lead to further price decreases.

In a next step, the potentials investigated in this study should be mirrored against the cost of different options to find Switzerland’s road ahead. This concerns the cost of interconnector capacity expansion as well as all other costs altering the supply and demand (in particular nuclear, energy efficiency and renewable policy).

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A Annex

A.1 Tables

Table A-1: OLS and GMM estimation results

Dependent variable: CH electricity spot price	**OLS** Coefficient	Std. Err.	**IV-GMM** Coefficient	Std. Err.
CH load	0.00391***	(0.00015)	0.01678***	(0.00176)
CH renewables generation	-0.02734***	(0.00183)	-0.03770***	(0.00625)
CH unavailable generation capacity	0.00049***	(0.00007)	0.00043**	(0.00021)
CH holiday	-5.30115***	(0.40487)	-1.74077	(1.38794)
AT/DE renewables generation (congestion)	-0.00016***	(0.00001)	-0.00013***	(0.00003)
AT/DE renewables generation (no cong.)	-0.00029***	(0.00002)	-0.00028***	(0.00005)
AT/DE unav. generation cap.(congestion)	-0.00021***	(0.00001)	0.00006	(0.00005)
AT/DE unav. generation cap. (no congestion)	0.00006***	(0.00002)	0.00018***	(0.00005)
AT/DE holiday (congestion)	-0.89582	(0.98270)	1.20426	(2.33796)
AT/DE holiday (no congestion)	2.07350**	(1.00936)	5.63478**	(2.69509)
FR renewables generation (congestion)	-0.00072***	(0.00006)	-0.00071***	(0.00016)
FR renewables generation (no congestion)	-0.00042***	(0.00009)	-0.00063***	(0.00022)
FR unav. generation capacity (congestion)	0.00019***	(0.00002)	0.00021***	(0.00005)
FR unav. generation capacity (no cong.)	0.00017***	(0.00002)	0.00031***	(0.00005)
FR holiday (congestion)	-0.08717	(0.75922)	-3.19731	(3.63897)
FR holiday (no congestion)	-0.88156	(1.01197)	-0.82119	(2.27978)
IT renewables generation (congestion)	0.00032***	(0.00011)	-0.00084**	(0.00038)
IT renewables generation (no congestion)	0.00028*	(0.00017)	-0.00120**	(0.00049)
IT unav. generation capacity (congestion)	-0.00050***	(0.00003)	-0.00044***	(0.00008)
IT unav. generation capacity (no cong.)	-0.00031***	(0.00004)	-0.00029**	(0.00012)
IT holiday (congestion)	-1.91038***	(0.55327)	-1.65713	(1.63572)
IT holiday (no congestion)	-2.89530***	(0.59068)	-0.98985	(1.94149)
Hard coal price	0.05575***	(0.00409)	0.03916***	(0.00969)
Natural gas price	0.15784***	(0.01005)	0.08139***	(0.02675)
Crude oil price	0.01175***	(0.00360)	-0.01907**	(0.00928)
AT/DE congestion	10.10314***	(0.63691)	4.67924***	(1.30656)
FR congestion	0.32608	(0.59509)	3.89660***	(1.17540)
IT congestion	1.75193***	(0.35851)	0.35604	(0.88201)
Constant	8.18510***	(1.39840)	-80.09468***	(12.25714)
Obs.	15696		15696	
R^2	0.744		0.558	
First Stage F-Test (CH load)	-		270.042	

Notes: IV-GMM results derived from two-step feasible GMM estimation. Standard errors robust to heteroscedasticity and autocorrelation. *,**,***: significant at 10%, 5% and 1% respectively.

Table A-2: Integration indices based on OLS and GMM estimation results

	OLS			IV-GMM		
	Index 1	**Index 2**	**Index 3**	**Index 1**	**Index 2**	**Index 3**
AT/DE	1.720	1.623	1.151	1.046	1.041	1.017
FR	0.980	0.995	1.053	1.010	1.011	1.015
IT	1.086	1.066	0.946	0.996	0.996	0.998
Overall	1.544	1.524	0.956	1.052	1.050	1.001

Table A-3: Sensitivity results based on IV estimation results

	Index 1	**Index 2**	**Index 3**
	Congestion = Price difference > 0.5		
AT/DE	1.041	1.039	1.014
FR	1.000	1.002	1.013
IT	0.996	0.996	0.999
Overall	1.039	1.038	1.005
	Congestion = Price difference > 2		
AT/DE	1.054	1.045	1.024
FR	1.016	1.016	1.015
IT	1.000	1.000	0.999
Overall	1.070	1.064	1.012
	Congestion = Price difference > 3		
AT/DE	1.066	1.050	1.025
FR	1.019	1.019	1.020
IT	1.006	1.004	1.000
Overall	1.093	1.073	1.018
	Congestion = Price difference > 4		
AT/DE	1.067	1.051	1.032
FR	1.023	1.024	1.025
IT	1.005	1.003	1.000
Overall	1.091	1.064	1.029
	Congestion = Price difference > 5		
AT/DE	1.072	1.052	1.032
FR	1.029	1.028	1.028
IT	1.003	1.001	1.000
Overall	1.096	1.057	1.029

Table A-4: Generation mix changes in neighboring countries until 2020

Bidding zone	Wind + Solar	Other renewa-bles	Nuclear	Fossil fuels
Germany/ Austria	targeted yearly generation of 150,941 GWh	targeted yearly generation of 118,371 GWh	installed capacity -2812 MW (deactivation of Grundremmingen (2017) and Philippsburg (2019))	installed capacity -2900 MW (lignite) (deactivation of Buschhaus (2016), Frimmers-dorf P+Q (2017), Niederaußem E+F (2018) Jänschwalde F (2018), Jänschwalde E (2019), Neurath C (2019))
France	targeted yearly generation of 64,785 GWh	targeted yearly generation of 90,499 GWh	installed capacity -1840 MW (deactivation of Fessenheim as only plausible possibility)	-
Italy (North)	targeted yearly generation of 3,801 GWh	targeted yearly generation of 35,506 GWh	-	installed capacity -870 MW (hard coal) and -520 MW (oil) (deactivation of Fusina1-4 and Spezia as only plausible possibility)

Notes: “Other renewables” comprise hydro, ocean, geothermal, and biomass. Yearly renewables generation for Italy North derived by scaling whole Italy targets with respect to share of actual generation in Italy North on actual generation in whole Italy in 2015.
Sources: own research; national action plans regarding EU 2020 renewable energy targets (https://ec.europa.eu/energy/en/topics/renewable-energy/national-action-plans, accessed: April 2017)

A.2 Figures

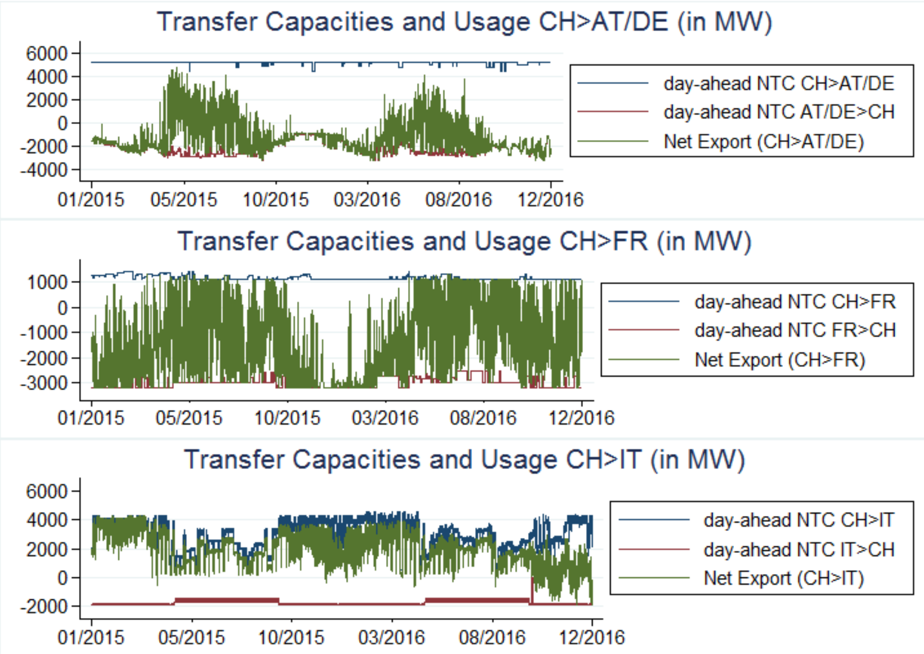

Figure A-1: Transfer capacities and usage by border

Notes: Net export based on total scheduled commercial exchanges.

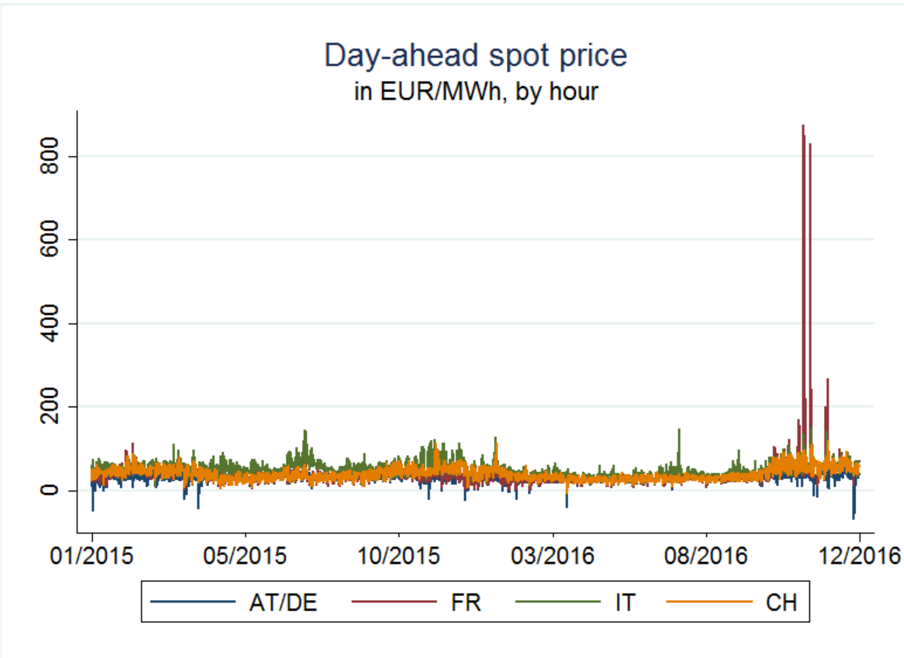

Figure A-2: Electricity prices

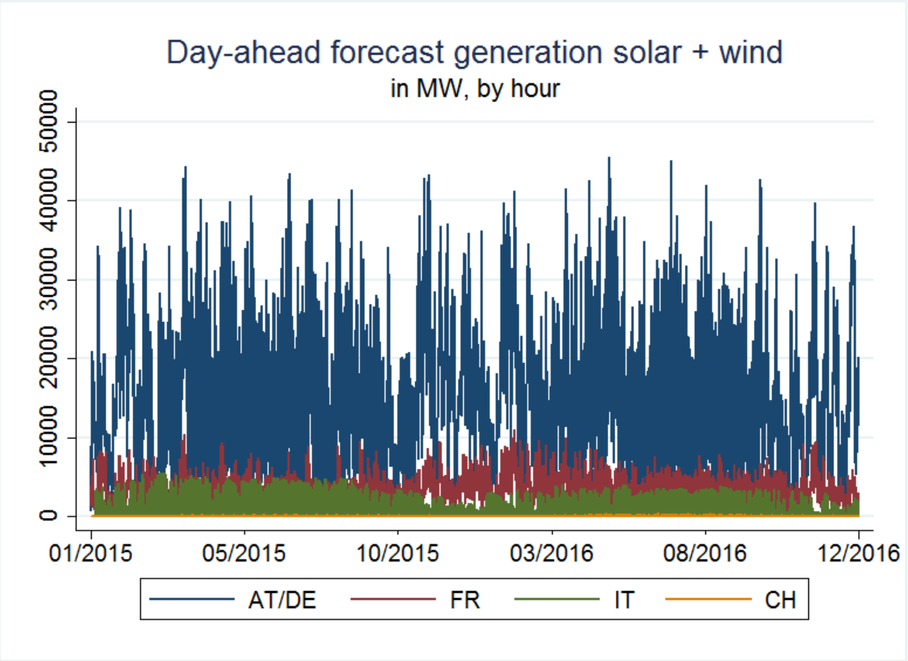

Figure A-3: Day-ahead renewables generation forecast

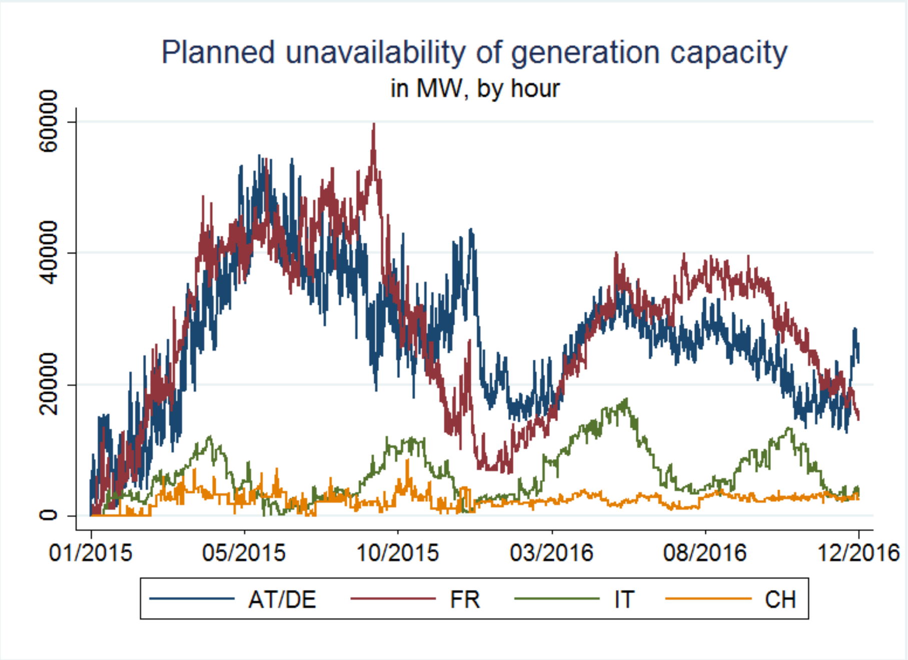

Figure A-4: Unavailable generation capacity

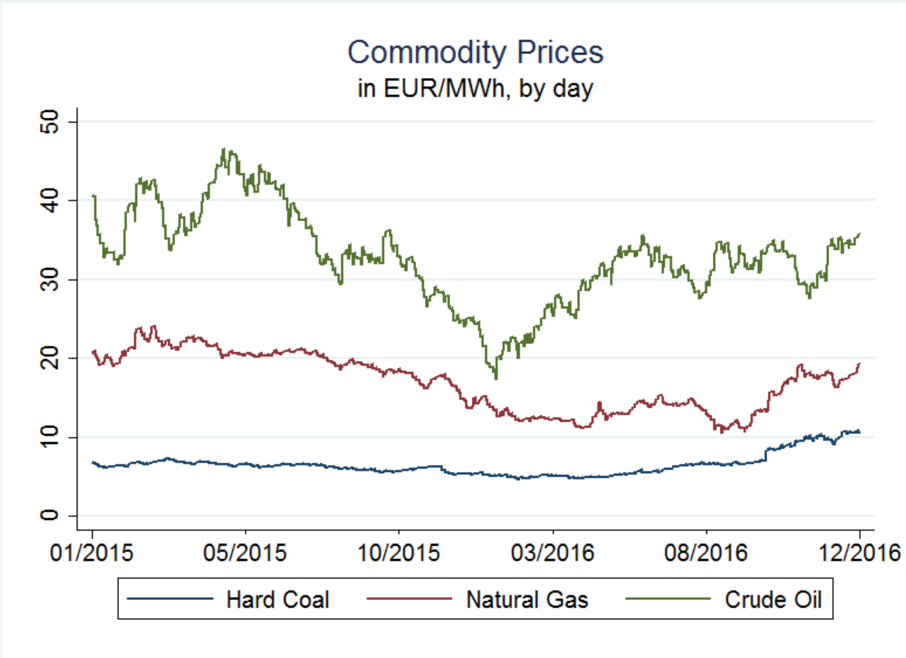

Figure A-5: Commodity prices

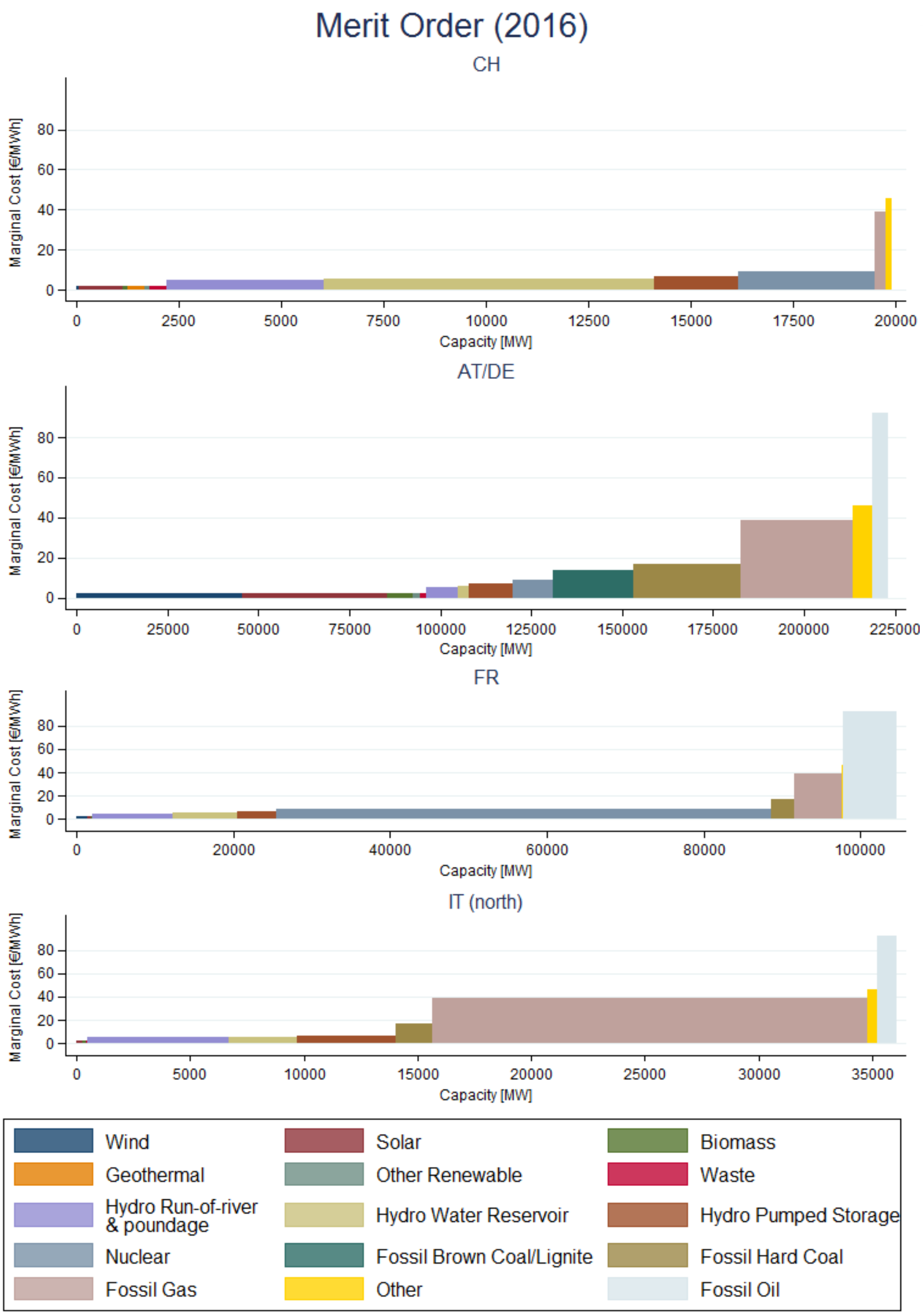

Figure A-6: Country merit-orders

Sources: ENTSO-E (2017), SFOE (2016a, 2016b)