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Schweizerische Akademie der Technischen Wissenschaften
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Ist das geplante Stromsystem der Schweiz für die Umsetzung der Energiestrategie 2050 aus technischer Sicht geeignet?

Swiss Energy Strategy 2050 and the Consequences for Electricity Grid Operation – Full Report

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Zusammenfassung in Deutsch

Szenario-Grundlagen der Studie

Die vorliegende Studie analysiert die Auswirkungen der einzelnen Stromerzeugungs- und Stromverbrauchsszenarien der BFE Energiestrategie 2050 (Abb. 1) auf das Schweizer Stromnetz und die Speicherbewirtschaftung, sowohl Pumpspeicher als auch saisonale Speicherseen.

Des Weiteren wird ein Verbrauchsszenario mit signifikant höherem Stromverbrauch (+50%) im Jahr 2050, basierend auf Studien von IEA und EUREL, und verschiedene Erzeugungsszenario mit hohem PV-Energieanteil im Jahr 2050 analysiert.

Mit dem vom Bundesrat anvisierten Atomausstieg, sprich die langfristig geplante Ausserbetriebnahme aller fünf Schweizer Kernkraftwerke in den nächsten zwei Jahrzehnten ohne einen Neubau von Kernkraftwerken, wird der Schweizer Netto-Stromimport im Jahr 2050 zwischen 24 TWh und 46 TWh jährlich betragen (abhängig von der Entwicklung des Schweizer Stromverbrauchs von heute bis ins Jahr 2050).

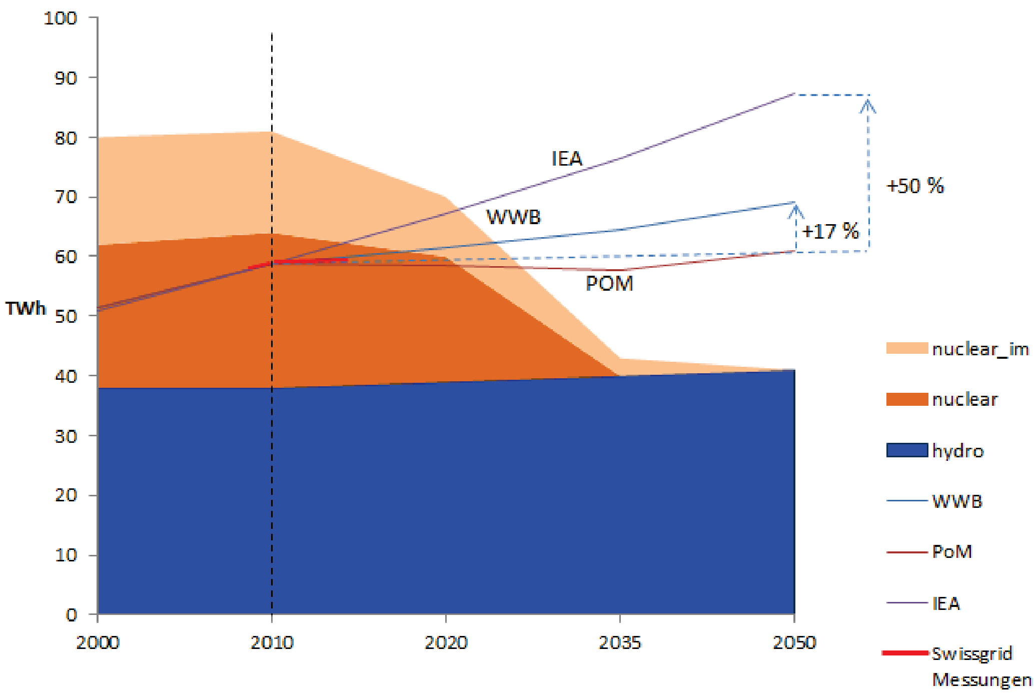

Abbildung 1 – BFE Elektrizität Nachfrage Szenarien

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Durchführung der Studie

Zeitreihen-Simulationen basierend auf einem elektrischen Modell des europäischen Stromsystems mit 29 Ländern werden für einzelne Referenzjahre mit hoher Zeitauflösung durchgeführt (8‘760 stündliche Simulationsschritte pro Referenzjahr).

Das verwendete Simulationsmodell besteht aus

- dem europäischen Stromnetzmodell,
- dem Kraftwerkspark-Portfolio in jedem Land
- landes-typische Lastverbrauchskurven und Wind/PV-Einspeisezeitreihen für die einzelnen Länder in stündlicher Auflösung für das jeweilige Referenzjahr

Unterschiedliche Kraftwerkstypen, sprich Kohle-KWs, Gas-KWs, KKWs, Wind Onshore, Wind Offshore, PV, Solarthermische KWs, Pumpspeicher, Speicherseen, Laufwasserkraftwerke) sind mit ihren jeweiligen Eigenschaften abgebildet (installierte Leistung und ggf. Energiespeicherkapazität).

Die Schweiz wird explizit nicht als Strom*insel* betrachtet, sondern ganz im Gegenteil als neuralgischer Knoten im gesamteuropäischen Stromnetz mit grossen Transit-Lastflüssen (insgesamt 25 TWh Strom direkter Transit durch die Schweiz, Import: 31TWh, Export: 32TWh, bei einem CH-Jahresverbrauch von ca. 59 TWh).

Das Schweizer Stromsystem wird durch 5 Regionen (Wallis, Tessin, Graubünden, restliche Deutschschweiz, restliche Westschweiz) abgebildet. Hierbei werden insbesondere die Kapazitäten der vorhandenen Speicherseen modelliert (Abb. 2).

Abbildung 2 – Aufteilung des Schweizer Hochspannungsnetzes in fünf Teilregionen

Die restliche Modellaggregation findet auf Länderebene statt (29 Länderknoten). Das Europäische Stromsystem-Modell wird zusammen mit dem detaillierteren Schweizer Stromsystem-Modell in integrierter Form simuliert (Abb. 3).

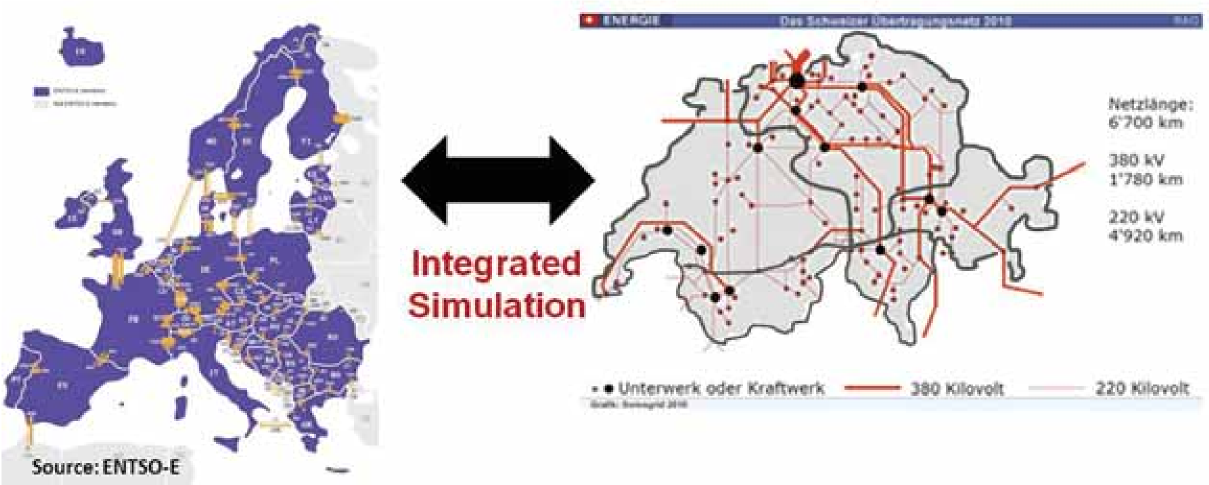


Abbildung 3 – High-Level Modellierung des Europäisches Stromnetzes und detaillierte Modellierung des Schweizer Stromnetzes

Speicherelemente im ganzen Europäischen Stromnetz, sprich Pumpspeicher und [saisonale] Speicherseen, werden mit ihren Turbinen/Pump-Leistungen und Energiekapazitäten der Speicher in den Simulationen explizit berücksichtigt. Die Pumpspeicherdaten basieren auf einer Studie von Eurelectric.

Der Kraftwerkseinsatz (Dispatch) im gesamten europäischen Stromsystem basiert auf einer sogenannten prädiktiven Marginalkosten-Optimierung, die vorhandene Vorhersagedaten zu zukünftigem Lastaufkommen als auch Wind/PV-Einspeisung über die kommenden Tage, explizit mit berücksichtigt.

Annahmen

Die Marginalkosten der Stromerzeugung der einzelnen Kraftwerkstypen basieren auf veröffentlichten Kostendaten der IEA [1] und eigener Analyse (vor allem bei der Wasserkraft). Die zurzeit anvisierten Ausbaupläne für das europäische Stromnetz, sprich Kraftwerkskapazitäten und Stromtransportkapazitäten [2], [3], werden im vollen Umfang realisiert.

Die modellierten Stromtransportkapazitäten zwischen den europäischen Ländern entsprechen den von der ENTSO–E veröffentlichten Netto-Austauschkapazitäten (*Net Transfer Capacities* [NTC]) für das Referenzjahr 2020, entsprechend dem «Ten-Year Development Plan of ENTSO-E» [3]. Im Fall der Schweiz werden als konservative Annahme die (niedrigeren) NTC-Werte für das Sommerhalbjahr 2010 verwendet. Die Stromverbrauchs- und Wind/PV/Hydro-Zeitreihen für jedes europäische Land basieren auf Szenarien des EU-Forschungsprojekts IRENE-40 (Infrastructure Roadmap for Energy Systems in Europe) für die Referenzjahre 2010, 2020, 2030, 2040, 2050 [4].

Basierend auf IRENE-40-Daten wird für das Jahr 2050 von Wind- & PV-Kapazitäten von 600 GW bzw. 865 GW in Europa ausgegangen (im sogenannten High Renewables Szenario). Im Vergleich dazu: Ende des Jahres 2010 waren insgesamt 84 GW Windturbinen- und 29 GW PV-Leistung in der EU installiert. Allein bis Ende 2012 stieg die installierte Leistung auf 106 GW Windturbinen- und 69 GW PV-Kapazität an (REN21 Global Status Reports 2011–2013).

Eine weitere Annahme im Simulationssetup ist, dass der europäische Strombedarf (ohne die Schweiz) bis zum Referenzjahr 2050 um durchschnittlich 50% bis 60% ansteigt (IRENE-40 Szenarien). Die Entwicklung des Schweizer Stromverbrauchs basiert auf den verschiedenen BFE-Nachfrageszenarien (Stromverbrauchszuwachs bis 2050: +0-17%) und zusätzlichen dem IEA-Szenario (Stromverbrauchszuwachs bis 2050: +50%).

Die Modellierung der fünf Schweizer Regionen, also Kraftwerksparks, Speicherseen Energiekapazität, Last/Wind Zeitreihen, basieren auf BFE-Statistiken (für das Referenzjahr 2010 [5] [6]) und dem BFE-Energieszenario 2050 (für die Referenzjahre 2020, 2035, 2050).

Die angenommenen Stromtransportkapazitäten zwischen den fünf Schweizer Regionen basierend auf den verfügbaren Swissgrid-Netzdaten für das geplante Übertragungsnetz im Jahr 2020 (Netzmodell des Hochspannungsnetzes von Swissgrid [150/220/380kV-Ebene], Plan 2020, siehe Abb. 4).

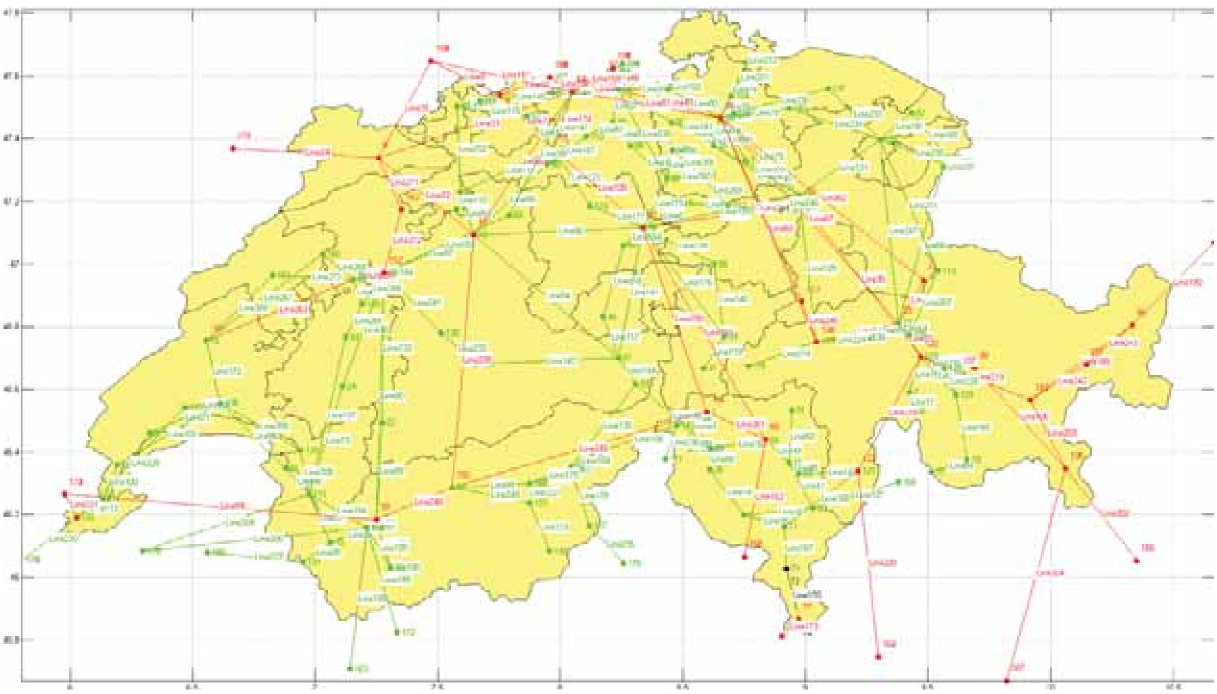


Abbildung 4 – Das Schweiz Stromnetz (basierend auf dem Netzmodell für das Jahr 2020, rot: 380 kV, grün: 220 kV, schwarz: 150kV -- Quelle: swissgrid)

Die PV-Zeitreihen basieren auf Datensätzen des Bundesamts für Meteorologie und Klimatologie (MeteoSchweiz) für das Jahr 2013. Daten von insgesamt 11 Wetterstationen in der Schweiz werden benutzt.

Aufgrund hierzu fehlender Statistikquellen wird die Energiekapazität der existierenden Schweizer Pumpspeicher auf ca. 50 GWh geschätzt (Eine Sensitivitätsanalyse zeigt, dass dieser Parameter, die Energiekapazität der Pumpspeicher, im Übrigen die Simulationsergebnisse nicht signifikant beeinflusst.) Die gesamte verfügbare Pump-/Turbinenkapazität liegt heute bei ca. 1.8 GW (BFE). Pläne und Bauprojekte für eine Erweiterung der Pump-/Turbinenkapazität auf ca. 5–6 GW bis zum Zeitraum 2020–25 existieren.

Die Speicherbewirtschaftung der Speicherseen basiert im hier benutzten Simulationssetup auf jährlich konstanten sogenannten Wasserwerten (water value).

Das CH-Verteilnetz in jeder Region wird, mangels vorhandener Daten, nicht modelliert. Die Studienannahme ist, dass das Verteilnetz mit steigenden Erzeugungsanteilen an Wind&PV-Strom entsprechend verstärkt und ausgebaut wird, um die Erzeugung aus Erneuerbaren Energien aufnehmen zu können. Die Studienannahme ist also, dass das Verteilnetz aufgrund geeigneten Ausbaus nicht zum «Engpass» im täglichen Netzbetrieb wird.

Zusätzlich wurde analysiert, welche Effekte ein fehlender Ausbau des Übertragungsnetzes und der Pumpspeicherkapazitäten auf die Landesversorgung hätte. Für dieses Infrastruktur-Szenario wurde der heutige Ausbaustand des Schweizer Übertragungsnetzes (Netzmodell des Hochspannungsnetzes von Swissgrid [150/220/380kV-Ebene], Stand 2010, siehe Abb. 5) und die heute existierenden Pumpspeicherkapazitäten von 1.8 GW (BFE).

Abbildung 5 – Das Schweiz Stromnetz (basierend auf dem Netzmodell für das Jahr 2010, rot: 380 kV, grün: 220 kV, schwarz: 150kV -- Quelle: swissgrid)

Anmerkung zu den Studienergebnissen

Alle hier dargelegten Simulationsergebnisse entsprechen Aussagen über die ***technische Integrationsfähigkeit*** des Stromtransportnetzes (Netzebene 1, 220-380kV) für die anfallende Stromerzeugung aus Wind- & PV-Anlagen als auch Laufwasserkraftwerken im Schweizer Stromnetz bzw. im europäischen Stromnetz.

Im besonderen Fokus in den Fragestellungen der Studie lag bei den für eine zuverlässige Landesversorgung notwendigen Import-/Exportkapazitäten mit den Nachbarländern der Schweiz als auch den innerhalb der Schweiz verfügbaren hydraulischen Energiespeichersystemen, also den Pumpspeichern und Speicherseen. Für diese Art von Fragestellungen ist das Übertragungsnetz von entscheidender Bedeutung.

Insbesondere beim geplanten PV-Ausbau, wird allerdings das Thema Ertüchtigung der Stromverteilnetze (Netzebene 3-7) ebenfalls eine wichtige Rolle spielen. Hier können neben dem klassischen Leitungsausbau auch dezentrale Speichersysteme und Lastmanagement sinnvoll sein, um die PV-Spitze zur Mittagszeit zu absorbieren und damit die erzwungene Abschaltung von fluktuierender Stromerzeugung zu vermeiden. Der (kosteneffiziente) Netzausbau auf allen Netzebenen, im Übertragungs- wie auch im Verteilnetz, wird ein Schwerpunkt der Energiewende (im Strombereich) sein. Aktuelle Studien der Schweizer Verteilnetzbetreiber zu den Auswirkungen grosser Anteile dezentraler Stromerzeugung, insbesondere von PV-Anlagen, auf die Verteilnetze als auch geeignete Verteilnetzausbau- und Ertüchtigungsmassnahmen werden u.a. im Rahmen des Vereins Smart Grid Schweiz erarbeitet [7]. Eine aktuelle ETH-Studie zeigt, dass die Schweizer Verteilnetze zum Teil über 50% PV-Strom (bezogen auf den jährlichen Stromverbrauch) integrieren können [8, p. 105].

Alle Simulationsresultate sind das Ergebnis einer ökonomischen, europaweiten Dispatch-Optimierung basierend auf den Marginalkosten der einzelnen Kraftwerke, mit einer Einspeise-Priorität für fluktuierende Erneuerbare Energien inklusive der Laufwasserkraftwerke. Dies wird in den Simulationen durch negative Marginalkosten für Erneuerbare Stromproduktion abgebildet, die aus Sicht der Anlagenbetreiber Kompensationszahlungen bzw. aus Sicht der Netzbetreiber Strafzahlungen für die Nicht-Abnahme entsprechen (wie z.B. im deutschen EEG-Fördersystem implementiert).

Da der Fokus dieser Studie auf der technischen Machbarkeit der Energiewende für das Schweizer Stromnetz und deren Auswirkung auf die Speichernutzung (Pumpspeicher als auch Speicherseen) und die Stromimport/-export-Muster zwischen der Schweiz und den Nachbarländern liegt, wurde keine Abschätzung der notwendigen Investitionskosten im Verteilnetz und die volkswirtschaftlichen Auswirkungen der einzelnen Szenarien der BFE Energiestrategie für die einzelnen Szenarien durchgeführt. Hierzu gibt es bereits nationale Studien von BFE/Prognos [9], dem VSE [10] und der ETH Zürich [11] für die Schweiz als auch trilaterale Studien für die DACH-Länder [12]. Die Bandbreiten der der in diesen Studien abgeschätzten notwendigen Investitionssummen sind gerade für das Verteilnetz z.T. sehr gross. Da die Struktur der Verteilnetze sehr heterogen ist (Stadt/Agglomeration/Land) und die Möglichkeiten für Netzverstärkungsmassnahmen zumal im Smartgrid-Kontext deutlich komplexer werden, sind hohe Unsicherheiten bei der Abschätzung des Verteilnetzinvestitionsbedarfs kaum vermeidbar. Um doch eine Grössenordnung der Investitionsosten für den

Netzausbaubedarf einer Kommune zu erhalten, hat Repower am Beispiel der Stadt Ilanz, auf Basis aktueller Solarkatasterdaten das mögliche PV –Potential ermittelt und den notwendigen Netzinfrastrukturausbau berechnet (siehe Text-Box).

Fallstudie – Ausbaubedarf des Verteilnetzes in Ilanz

Die zukünftigen Stromversorgungsnetze werden intelligenter, sie werden zu Smart Grids. Zur Entwicklung eines gemeinsamen Verständnisses von Smart Grids bündelten 13 grössere Schweizer Elektrizitätsunternehmen ihre Aktivitäten im Verein Smart Grid Schweiz (VSGS). Einen Teil seiner Arbeiten veröffentlichte der VSGS 2013 im Weissbuch Smart Grid (www.smartgrid-schweiz.ch).

Drei wesentliche Treiber verändern das Verteilnetz

1. **Dezentrale Einspeisung**: Die vermehrte und laufend wachsende dezentrale Stromeinspeisung erfordert eine Anpassung der Stromnetze, insbesondere der für die Ausspeisung konzipierten Verteilnetze. Notwendig sind Smart Grids im engeren Sinne.

2. **Energieeffizienz**: Um den Stromverbrauch zu reduzieren und die Energieeffizienz zu erhöhen, braucht es effizientere, Strom sparende Endgeräte. Eine intelligente Steuerung (Smart Home) kann die gesetzten Ziele zusätzlich unterstützen. Der Verbraucher braucht Informationen über seinen Stromverbrauch um aktiv werden zu können. Smart Meter sind ein mögliches Hilfsmittel dazu.

3. **Veränderliche Produktion**: Die Stromproduktion wird fluktuierender und stochastischer. Das kontinuierliche Sicherstellen des Gleichgewichts zwischen Stromproduktion und Stromkonsum wird komplexer und setzt auch Massnahmen auf der Verbraucherseite voraus. Es braucht neue Instrumente, Smart Markets, wie flexible Tarife, Demand Response oder Energiespeicher. Produzenten und Verbraucher müssen intelligent agieren.

Auswirkungen der dezentralen Einspeisung

Ein entscheidender Faktor ist natürlich die Anzahl und Grösse dezentraler Produktionsanlagen, die einen Aus- und Umbau der bestehenden Elektrizitätsnetze erfordern sowie die bestehende Netzstruktur. Netzbetreiber mit ländlichen Strukturen, langen Zuleitungen und geringeren Bevölkerungsdichten aber grossem Potential für Solaranlagen haben eine andere Ausgangslage als städtische Netzgebiete mit Netzen welche für grössere Leistungen ausgelegt sind. Somit sind die Auswirkungen von Fall zu Fall zu ermitteln, was eine generelle Abschätzung der Netzausbaukosten schwierig macht. Spannungsänderungsabweichungen beim Endverbraucher sind ein wesentlicher Faktor, welche in Abhängigkeit der unterschiedlichen Last- und Produktionsspitzen beim Kunden resultieren. Das erlaubte Spannungsband kann unter Umständen nicht mehr eingehalten werden, was ohne entsprechende Massnahmen zur Beeinträchtigung oder gar zur Zerstörung angeschlossener Geräte führen kann. Ein weiterer Faktor ist die Überlastung von Netzkomponenten (z.B. Kabelleitung), welche zu Netzausfällen und Defekten führen kann. Es gibt noch eine Reihe weiterer Faktoren wie z.B. die erhöhten Netzrückwirkungen, welche mit entsprechenden Massnahmen reduziert werden müssen.

Massnahmen zur Bewältigung der Auswirkungen

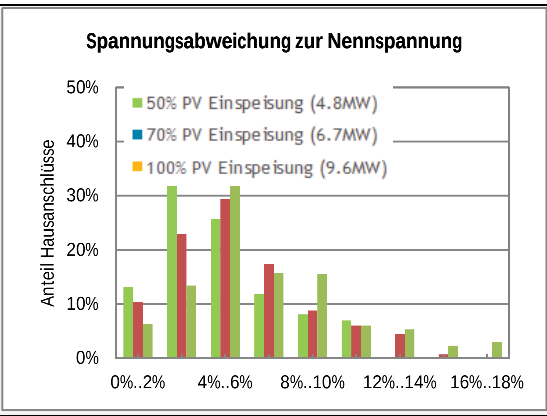
Bereits heute laufen Bestrebungen, die Stromnetze intelligenter, zu sogenannten Smart Grids, zu machen, um mit den komplexeren Situationen umgehen zu können. Dabei muss beachtet werden, dass ein Smart Grid einen konventionellen Netzausbau nicht vollständig ersetzen kann, sondern je nach eingesetzten Komponenten und auftretenden Problemen unterstützend wirkt. Bei Spannungsschwankungen kann beispielsweise ein regelbarer Ortsnetztransformator oder eine Blindleistungsregelung der Energieerzeugungsanlage Abhilfe schaffen. Bei Überlastungen von Leitungen kann eine Abregelung der Produktionsanlage oder eine dynamische Steuerung der Lasten (z.B. über die Rundsteuerung) helfen.

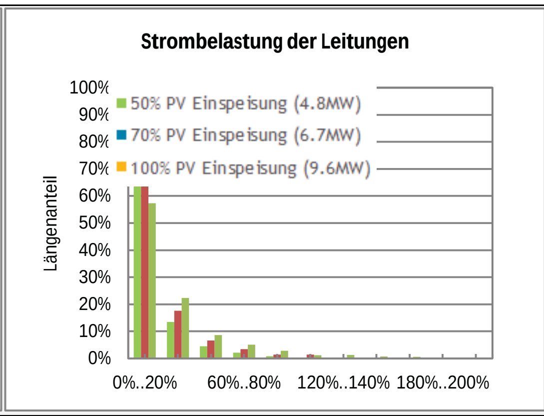
Auch die Energiespeicherung kann ein wesentlicher Bestandteil eines zukünftigen Smart Grids sein. Im Verteilnetz platzierte Speicher können dann für die Optimierung der Netznutzung eingesetzt werden, indem Last- bzw. Produktionsspitzen von dezentralen Erzeugungsanlagen ausgeglichen werden.

Am Beispiel der Stadt Ilanz (Kanton GR) wurde mittels aktuellen Solarkatasterdaten das mögliche PV-Potential ermittelt und anschliessend in einer Simulation der notwendige Ausbau der Netzinfrastruktur berechnet. Dabei hat man das gesamte Netz bis zum Hausanschluss mit den effektiven Leitungs- und Anlagenwerten nachgebildet. Bei 50% PV-Ausbau sind nur geringfügige Anpassungen am Verteilnetz nötig. Bei Ausschöpfung der maximalen PV-Produktion müssten rund 825 TCHF in neue Netzkomponenten investiert werden, je etwa zu einem Drittel in Kabel mit grösserem Querschnitt, in zusätzliche Kabelanlagen und in grössere Transformatoren. Auf diese recht aufwendige Art und Weise kann man in Einzelbetrachtungen für eine konkrete Region die zu erwartenden Kosten des nötigen Netzausbaus bestimmen. Diese und weitere Untersuchungen haben gezeigt, dass sich die Problematik der Spannungshaltung deutlich relevanter ausprägt als die Strombelastungen der Leitungen.

Auf Grund der Heterogenität der Schweizer Verteilnetze ist eine generelle Aussage über den nötigen Netzausbau und somit über die auftretenden Kosten für die ganze Schweiz ohne eine Einteilung in Referenznetze kaum möglich. Unter den möglichen Ausbauvarianten ist diejenige der Abregelung von PV-Einspeisung eine sehr effektive und günstige Variante, welche es aber gesetzlich zu regeln gilt.

Weitere Untersuchungen und Resultate veröffentlicht der VSGS im Laufe des Jahres [7].





Bsp. Ilanz			
Einwohner	ca. 2500	Gesamtlänge der Leitungen auf NE7	32.1km
Einwohner pro m^2 Bauzone	ca. 0.003	Gesamtlänge der Leitungen auf NE5	10.2km
Anzahl Hausanschlüsse	430	Maximale Gesamtlast	4.15 MW
Anzahl Transformatoren	19	Maximale Produktionsleistung PV	9.6 MW
Total Trafoleistung	10.26 MVA	Nötige Ausbaukosten bei Vollausbau PV	ca. 825 TCHF

Autoren: Florian Felix, Gerhard Bräuer, Repower AG

Study in English

1 Introduction

After the Fukushima incident of March 2011, the Swiss federal government announced that Switzerland would gradually phase out nuclear power. In about two decades, the corresponding nuclear-based electricity generation, today about 26 TWh per year (TWh_e/y), will have to be partially substituted by other generation sources and partially absorbed by energy efficiency measures that aim to reduce the electricity consumption.

However, the overall Swiss electricity demand may, in fact, increase due to fossil fuel substitution both in the heating demand sector, i.e. via electric heat pumps, and the transport sector, i.e. via electric vehicles.

In this context, the Swiss Federal Office of Energy (BFE) has prepared the Energy Strategy 2050 for Switzerland, which outlines different generation scenarios that are apt to replace the electricity production of the existing nuclear power plants while satisfying different demand scenarios, ranging from a stagnating or even decreasing electricity demand (60.1 TWh_e/y) to a growing electricity demand (70 TWh_e/y, +17%) until the year 2050.

The BFE Energy Strategy 2050 foresees significant electricity production shares from Renewable Energy Sources (RES) that, depending on the generation scenario, reach up to 11 TWh_e/y from photovoltaic panels (PV) and 4 TWh_e/y from wind turbines. In addition, the generation capacities of biomass-fired, hydro-based and combined heat and power (CHP) plants will increase. The remainder of the electric load demand shall be either covered by electricity generation from up to five combined cycle gas turbine power plants (CCGT) or higher electricity imports from neighboring European countries.

Since solar and wind energy are variable electricity sources in essence, at high shares, they add a considerable uncertainty to the supply of electricity which could threaten the power balance and thus the stability and reliability of the Swiss electric power system. To prepare for and in the end avoid such events, the operational flexibility of the Swiss power system needs to be evaluated to understand its limit in integrating fluctuating renewable power generation from within Switzerland as well from other European countries, of which many are seeing rapidly increasing wind and solar energy shares.

This technical study evaluates the flexibility of the Swiss power system and derives the technical measures needed for the successful implementation of the BFE Energy Strategy 2050 for Switzerland, under the assumption that the production shares of Renewable Energy Sources (RES) will increase all over Europe in the coming decades.

Furthermore, we simulate an additional scenario for Switzerland, where the electricity demand will increase by +50% compared to the 2010 levels (90 TWh_e/y) according to the outlook of a study of EUREL and the International Energy Agency (IEA).

Figure 1 illustrates the different demand forecast scenarios for Switzerland and the gradual change in its electricity production mix. The depicted scenarios are defined as:

- **WWB** (Weiter wie bisher) stands for the BFE Business as Usual scenario,

- **POM** (Politische Massnahmen) stands for BFE Political Measures scenario which prioritizes energy efficiency.
- **NEP** (Neue Energiepolitik) stands for BFE New Energy Policy scenario which foresees more active political steps to achieve ambitious energy efficiency targets. Since electricity demand in this scenario is somewhat lower than in the other BFE scenarios, it has been omitted in this analysis, as the stress on the Swiss electricity transmission grid would either be similar (as in the POM scenario) or lower (as in the WWB scenario) than in the other BFE scenarios.
- **IEA** stands for the EUREL/IEA scenario with a 50% consumption increase in Switzerland until 2050.
- The red curve (Swissgrid Measurements) indicates the actual net electricity consumption of Switzerland from the years 2009 to 2013.

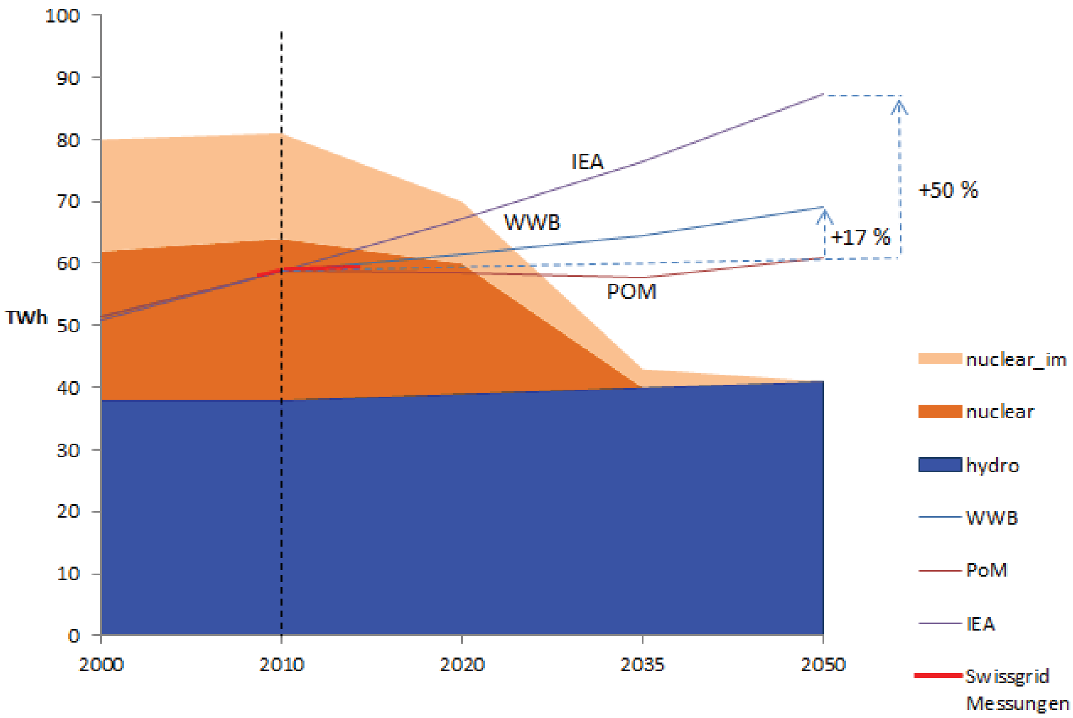


Figure 1 – IEA and BFE net electricity demand forecast in Switzerland (2010 – 2050) [Values taken from BFE Energieperspektiven (Table 7-60 on page 341 and data of Annex III), Swissgrid].

2 Modeling and Simulation Methods

2.1 Operational Flexibility in Electric Power Systems

The fundamental goal of power system operation is to keep a power balance between electricity production and consumption at all times. To do so, grid operators rely on the existing operational flexibility of their respective power system. The different flexibility measures are illustrated below:

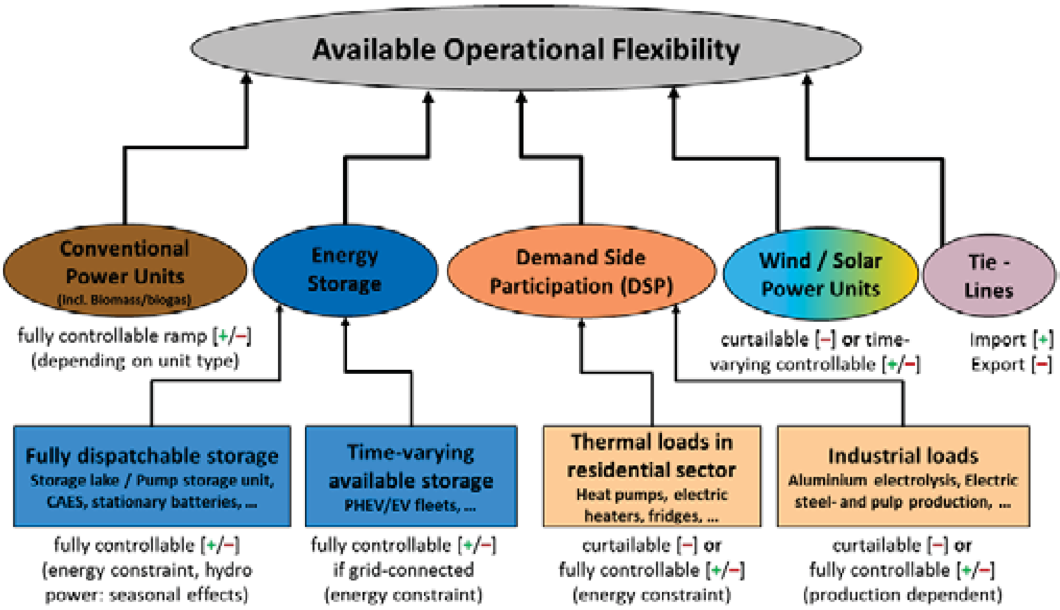


Figure 2 – Existing operational flexibility in power systems.

The [+/-] sign indicates that is technically possible for each flexibility source to modulate up or down its power in-feed to the grid or power out-feed out of the grid, thereby aiding the integration of Renewable Energy Sources (RES).

In case there is an excessive electricity production of solar or wind energy, several options for power balancing are possible, e.g.

- Conventional generation units can ramp down their power output,
- Excess energy production can be stored in pump storage lakes or batteries or in the form of heat energy in thermal storages (e.g. electric water &or space heaters,),
- Excess electricity production can be exported or, as last resort,
- Excess electricity production can also be curtailed.

In case of an electricity production shortage,

- Conventional generation units can ramp up their power output,
- Pump storage lakes or batteries can be emptied to provide additional power output,
- Lacking electricity production can be imported or
- Electricity demand can be reduced or shifted in time.

Under the given technical constraints, the actions with the least operational costs are given priority in the dispatch.

Please note that in this study, we do not evaluate the operational flexibility that Demand-Side Management (DSM) schemes, such as electric vehicles and thermal loads, could offer to grid operators for keeping the power balance.

Also, only the curtailability of wind and solar units, i.e. power modulation down [-] is considered. Time-varying controllability, where power modulation in both directions is possible, i.e. up & down [+/-], is not considered here. Such an operation mode is possible if wind and PV units are operated below their maximum possible electricity generation level in each time-step (delta-operation mode).

As large-scale energy storage, only Pumped-Hydro Storage (PHS) plants and Hydro Storage Lakes (HSL) are considered, as hydro-based energy storage is the only mature bulk energy storage technology today.

2.2 Important Assumptions

EU-27 + Norway

- **Renewable Energy Sources (RES)**
  - The National Renewable Energy Action Plans (NREAPs) of the respective European countries, as derived from the European Union's 20-20-20 goals, will be realized, meaning that all planned RES power plant capacity as well as related grid expansion plans will be delivered on time. Herein, our power system model is based on the European power system as it is projected to be in the year 2020 [3] [13].
  - Europe will follow the Renewable Energy Supply 2050 scenario developed by the EU FP7 research project IRENE-40 (Infrastructure Roadmaps for Energy Networks in Europe) [14], which projects the capacities of solar and wind plants to increase from the currently installed capacities, 31 GW PV and 84 GW wind turbines for year-end 2010 (and already 69 GW PV and 109 GW wind turbines by year-end 2012 [15]) to altogether 865 GW PV and 601 GW wind turbines in the year 2050. In the IRENE-40 RES scenario the overall European electricity demand is projected to increase by 60% from 2010 to 2050 due in part to the continuing electrification of the heat and transport sector [16].
- **Transmission Grid Model**
  - Each European country is represented by one node in the grid topology and is interconnected to its neighboring countries, i.e. the neighboring grid nodes, via the net transfer capacity (NTC) values as published by ENTSO-E [17].
  - One country node consists of its load demand, variable renewable profile in-feed (wind & solar & hydro) and its generation plant and storage unit portfolio, which are modelled individually for each generation technology.

Switzerland

- **Expansion Plans**
  - **Pumped Hydro Storage** The planned expansion of pumped-hydro storage plant capacities in Switzerland, about 4 GW additions projected until 2020–2025 (BFE [18, pp. Annex 1, Table 4]), will take place.
  - **Transmission Grid** Swissgrid's plan for transmission grid reinforcements for this decade ("Strategisches Netz 2020") will be delivered on time.
- **Grid Model**
  - Switzerland is sub-divided into five model regions, whose borders are along the cantonal borders and which are closely tied to the regions with large hydro reservoir capacities, i.e. Valais, Ticino, Grisons, remaining French-speaking cantons (Geneva, Vaud, Fribourg, Neuchatel, Berne and Jura) and the remaining Swiss German cantons.
  - The five regions are interconnected using an aggregated grid topology that is derived from a detailed model of the high-voltage Swiss transmission system (source: Swissgrid), thus representing the actual Swiss transmission grid as exactly as possible, including line constraints, but with only as much detail as necessary for this study's purposes.

Figure 3 – Transmission Grid of Switzerland (Plan for year 2020) – green: 220 kV, red: 380kV (Reproduction from Swissgrid grid model data).

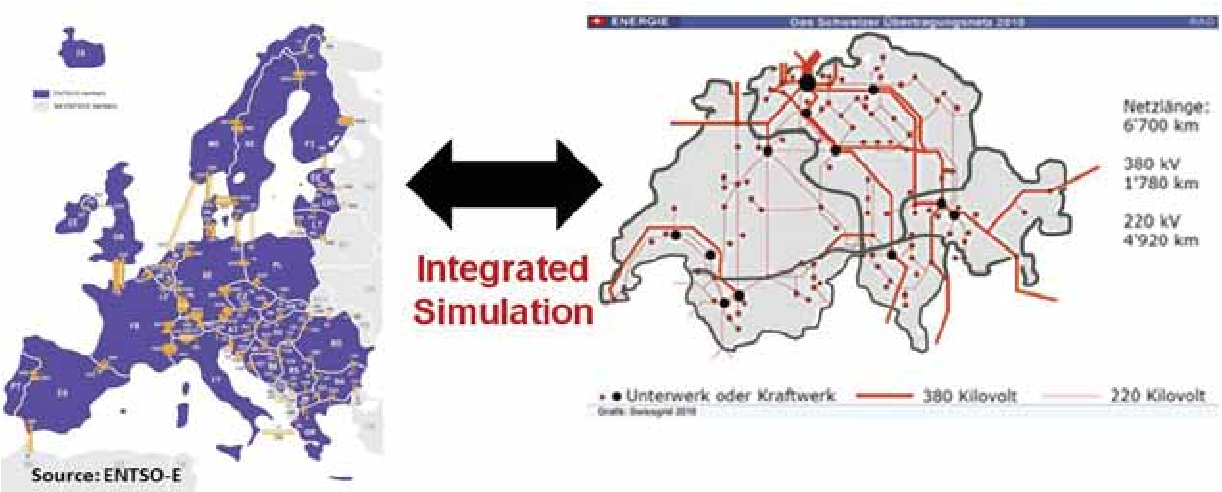


Figure 4 – Integrated Simulation of High-level model of the European Power System with detailed model of Swiss Power System.

All countries

- **Grid**
  - The electricity grids in all European countries are reinforced such that there are no significant country-internal bottlenecks due to decentralized PV and wind generation, either in the distribution or in the transmission grid.
  - ENTSO-E's transmission grid expansion plans for the reference year 2020, i.e. Ten-Year Network Development Plans (TYNDPs) are delivered on time.
- **Power Plants**
  - Conventional and Renewable Generation units, i.e. wind turbines, CSP, PV, run-of-river hydro, biomass and biogas, are modelled and simulated in an aggregated fashion (per technology and per country node [EU] or per region node [CH], taking into account relevant technical constraints such as power ramp-rate and energy capacity).
  - Hydro-based storage units, both storage lakes and pumped-storage hydro, are modelled and simulated in an aggregated fashion (per country node [EU] or region node [CH], differentiating between storage lakes and PHS, taking into account relevant technical constraints such as energy capacity and state-of-charge).
- **Power Dispatch**
  - The marginal costs for electricity production of each power plant type (conventional plants as well as RES plants) are based on an in-depth review study of electricity production costs conducted by IEA/NEA in 2010 [19]. Where applicable, a comparatively low CO_2 emission prices are considered (11 €/tonne in 2010 and 16 €/tonne for 2020 and beyond).

- Power Dispatch is accomplished using a Europe-wide predictive dispatch optimization for generation and (hydro) storage units that explicitly takes into account forecast information of load demand, wind and solar availability for the next day (24 h).

2.3 Data Framework

EU-27 + Norway

For the general modeling of all considered European countries, we have used statistical data from the EU FP7 research project IRENE-40 [14] as well as two additional sources, from the IEA (electricity generation costs) and from EURELECTRIC (pumped hydro storage capacities).

For the reference year 2020, the IRENE-40 data base provides the generation mix of every European country, the net transfer capacity (NTC) value for the electricity grid interconnectors between neighboring countries as well as the hourly times series for load demand and variable RES generation (photovoltaic, concentrated solar power, wind onshore and wind offshore).

For the reference years 2030, 2035, 2040 and 2050, synthetic, scaled-up hourly time-series of load demand as well as variable RES production have been employed (again from IRENE-40). For more information on the significance and validity of the data, please refer to the analysis presented in [20].

A recent EURELECTRIC report provides detailed figures on hydro power capacities in EU countries, detailing the power capacities of run-of-river plants, storage lake reservoirs and pump hydro storage (PHS). Vital to our model was the energy rating capacity of PHS that EURELECTRIC was able to group via a questionnaire they distributed to PHSs in Europe [21]. To obtain hourly time series for the run-of-river plants and hydro reservoirs in every EU country, we scaled up or down the latter based on the data we obtained for Switzerland from the Swiss Federal Office of Energy (BFE) [22].

Regarding electricity generation costs, the IEA presented a detailed study in 2010 [1]. The electricity generation costs were obtained from surveying 200 plants in 21 different countries and several industrial companies. The marginal costs include fuel costs and (variable) operation and maintenance (O&M) costs as well as CO_2 emission costs.

Switzerland

All employed modeling data is taken from the following sources

- Statistical data compiled and provided directly by BFE in [22], [23], [24], [25],
- Data from the BFE Energiestrategie 2050 report, conducted by the consultancy Prognos [9],
- Grid model data of the Swiss transmission grid as provided by swissgrid for the reference years 2010 and 2020 (including all planned grid expansion projects), and

- Data of planned or proposed pump storage expansion projects until the time period 2020–2025 [9].

The Swiss Power System

- Is partitioned into five sub-regions, whose borders were chosen according to cantonal borders and the location of mayor hydro reservoir and pumped storage capacities.
- Consistent data from BFE of installed power plant capacities, including energy storage capacity of storage lakes (but not pumped hydro storage units), is available for each Swiss canton.

Figure 5 illustrates the outlined partitioning of the Swiss Power Systems together with an overlay of the planned Swiss transmission grid for the year 2020.

Today's total installed energy capacity of hydro storage lakes, approximately 8780 GWh (≈15% of yearly Swiss net load demand), is distributed to the five regions according to statistical data from BFE [5] as follows

- **Valais (CH2)** Energy capacity of its hydro storage lakes is equivalent to 3980 GWh.
- **Ticino (CH3)** Energy capacity of its hydro storage lakes is equivalent to 1225 GWh.
- **Grisons (CH4)** Energy capacity of its hydro storage lakes is equivalent to 1980 GWh.

For the remaining Swiss cantons the energy capacity of its hydro storage lakes is evaluated to be about 1600 GWh. This capacity is further divided into two regions, i.e. the

- **Remaining Romandie plus Berne (CH1)** with a hydro storage lake energy capacity of approximately 850 GWh and
- **Remaining Swiss German cantons (CH5)** with a hydro storage lake energy capacity of approximately 750 GWh.

To estimate the monthly quantity of water influx, i.e. rain and snow melting, that fills the storage lakes, we use explicitly the monthly reservoir filling statistics data of Table 15 in the BFE Electricity Statistics [23] and add to it the difference between the monthly energy produced from hydro plants (Figure 12 in [23]) and the monthly energy that was extracted from reservoirs (table 15 of [23]).

The rationale behind that is further explained in the result section for the Swiss power system dispatch of 2010. The hydro reservoir filling time-series is then extrapolated from a monthly basis to an hourly basis.

To construct hourly run-of-river plant electricity production time-series, we extrapolated the weekly run-of-river production in Switzerland as given by BFE statistics to an hourly basis and normalized the production according to the five modeling regions.

Figure 5 – Partitioning of Switzerland into Five Sub-Regions.

For the load demand time-series, we used publicly available hourly data for the reference year 2010 (source: Swissgrid) and normalized it according to the population distribution of each region. The Swiss PV time-series are based on meteorological data that has been collected by 11 weather stations in Switzerland during the year 2011 according to the PV-LIB Toolbox developed by the Sandia National Laboratory [26]. The resulting regional PV electricity production time-series of the different BFE supply scenarios are then normalized according to the available rooftop areas (for placing PV panels) in each Swiss region. Overall there is about 470km2 of roof-top area in Switzerland [27, p. Fig. G4 and G10].

According to this distribution method for PV electricity production, the regional PV production shares would be as follows

- 8% of the generation will come from Wallis (CH-2),
- 34% will come from the remaining Romandie cantons plus Berne (CH-1),
- 5.6% will come from Ticino (CH-3),
- 4.6% will come from Graubünden (CH-4) and
- 47.5% will come from the remainder of Swiss German cantons (CH-5).

Figure 5 illustrates the time-series built for each region in Switzerland using the PV-LIB Toolbox developed by the Sandia National Laboratory [26]. PV panels are assumed to be fixed at an angle of 45 degrees oriented southwards. This is scaled-up according to the increasing PV target per decade as found in the BFE Energy Strategy 2050 [9]. The weekly PV production pattern for the month of August is shown here.

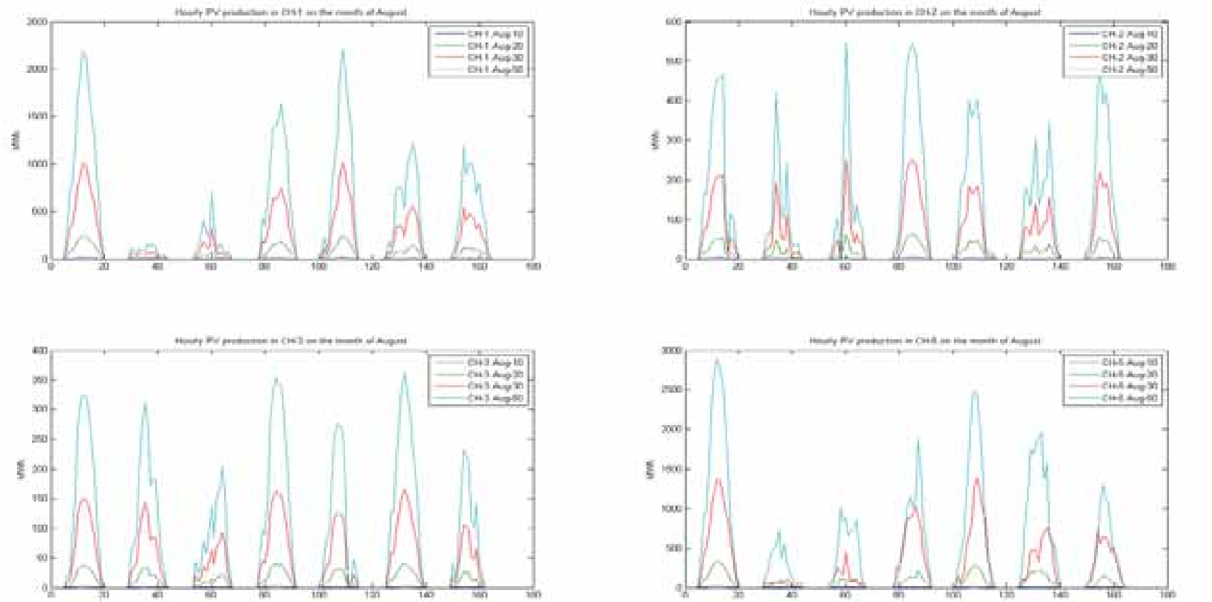


Figure 6 – Estimated Hourly PV Production in Each Swiss Region for a Week in August.

The variability of the PV electricity production time-series between the five regions can be clearly seen in Fig. 6. Our power dispatch simulations do explicitly consider the differing PV power in-feed time-series of the five Swiss regions. Wind turbine electricity production time-series for Switzerland come from the IRENE-40 database. Normalized wind in-feed profiles were created for each Swiss region according to the expected installed wind power capacities for the reference years. All future installed power plant capacities in Switzerland are based on BFE projections, given by [9], according to the respective supply scenario.

For the Swiss transmission grid model, we have aggregated the thermal line capacities with respect to the five regions using available transmission grid models for the reference years 2010 and 2020 (data source: Swissgrid). The aggregated thermal line capacities between the five Swiss regions would increase by 30% if all grid expansion projects are realized. The resulting transmission capacities of the line corridors are illustrated in Table 1.

Table 1 – Interregional thermal line capacities in Switzerland in 2010 and 2020.

Zone Connections	Line Limits 2010 (MVA)	Line Limits 2020 (MVA)
CH1 ↔ CH2	4’144	5’260
CH1 ↔ CH3	381	381
CH1 ↔ CH5	4’546	4’546
CH2 ↔ CH3	1’869	3’843
CH2 ↔ CH5	453	1’120
CH3 ↔ CH4	934	934
CH3 ↔ CH5	2’494	3’160
CH4 ↔ CH5	5’534	7’510
Total	**20’355**	**26’754**

For the reference year 2020, we assumed a rather low CO_2 cost of 15 €/tonne and an increase in fuel prices according to IRENE-40 scenario forecasts (50% for natural gas, coal and oil, 0% for uranium).

Table 2 **– Marginal cost of production of conventional power plants** [28].Table 3 – Marginal cost of production of renewable power **plants** [28] below present the marginal electricity generation costs for both conventional and renewable power plants. PV units and wind turbines have no fuel costs. Due to this their variable operation & maintenance (O&M) costs are either comparatively small (wind turbines) or even zero (PV). Due to the resulting structure of the merit-order curve, the dispatch optimizer prioritizes the power in-feed of wind&PV units over the – in terms of marginal costs – more expensive thermal and hydro-based units. This allows the evaluation of the power system's technical limits in integrating fluctuating power in-feed from wind&PV units.

Large hydro reservoirs offer significant operational flexibility. The assumed cost of hydro reservoir electricity generation, the so-called water value, depends directly on the production cost of the alternative generation unit, in case hydro storage lakes would not be used in a given situation (Optional valuation). The water value is in essence a design parameter that can be used to shape the seasonal state-of-charge curve of the hydro storage lakes according to the expectations of the seasonal load demand and water influx profiles, i.e. high load demand in winter and high water influx in spring and summer. The BFE has assembled a figure that presents the historical variation levels of Switzerland's hydro reservoirs over the past 40 years [23]. The heuristically determined water value of storage lake hydro units varies in the range of 70–120 €/MWh, depending on the consumption and supply scenario and the decade of the time-series simulation. In order to simplify matters, weighted average costs are calculated for each country node for coal and lignite power plants as well as for biomass-fueled CHP and biomass- or municipal waste-fueled power plants, respectively.

Table 2 – Marginal cost of production of conventional power plants [28]**.**

Power Plant	Fuel Import (€/GJ)	Emissions (tCO_2/MWh)	Efficiency (%)	Fuel Cost (€/MWh)	O&M (€/MWh)	Carbon Cost (€/MWh)	Total Cost (€/MWh)
Nuclear	0.72	-	36	7.2	9.1	-	16.3
Oil	13.4	0.62	45	107.2	4.3	6.2	117.7
Gas Turbine	7.5	0.37	45	60	4.14	3.7	67.8
CCGT	7.5	0.37	58	46.5	3.1	3.7	53.3
Coal	2.8	0.89	45	22.3	3.9	8.9	35.1
Lignite	1.3	0.94	43	10.5	4.04	9.4	23.9

Table 3 – Marginal cost of production of renewable power plants [28]

Power Plant	Fuel Cost (€/MWh)	O&M (€/MWh)	Carbon Cost (€/MWh)	Heat credit (€/MWh)	Total Cost (€/MWh)
Biomass-CHP	12.3	9.3	2.4	17.1	6.9
Biomass Solid	53.1	3.5	-	-	56.6

Municipal Waste	-	37.9	22.1	33.9	26.1
Geothermal	-	-	4.21	-	4.2
Hydro run-of-river	-	3.9	-	-	3.9
Pump hydro storage	-	8.12	-	-	8.1
Storage Lake Hydro	70–120				

2.4 Power Nodes Modeling Framework

The European power system is modeled as a system of interconnected power nodes, each one representing a country's generation and consumption portfolio. The Power Nodes Modeling Framework is a system-level unified approach that has been developed by the Power Systems Laboratory at ETH Zurich to include all relevant information on the observability and controllability of fluctuating power system units, the energy constrained capacity of storage units and the flexibility of demand units. The properties of each power system unit define the power node in question, which is embedded between a demand/supply-side and a grid-side. The work introduced in this section is based on [29], [30], [31]. Figure 7 illustrates the structure of a single power node.

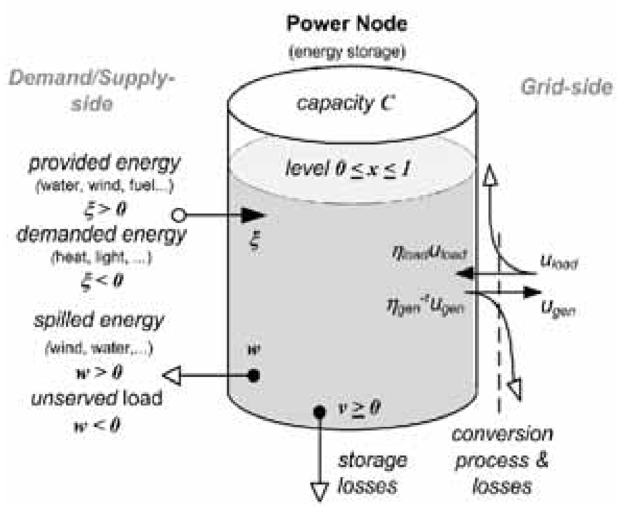


Figure 7 – Notation of a Single Power Node

The demand and supply process are lumped into the parameter ξ, with $\xi<0$ indicating end-use energy demand and $\xi>0$ energy supply. The possibility to curtail an external supply/demand process is lumped into the parameter w, with $w>0$ indicating curtailment of provided energy and $w<0$ curtailment of demanded energy. Physically curtailing solar or wind electricity production translates into disconnecting the plant from the grid, curtailing run-of-river electricity production requires to divert the water flow away from the plant's turbine.

A Power Node is characterized by the normalized level of the storage $0 \leq x \leq 1$, by the capacity of the storage $C \geq 0$ and by the storage losses $v \geq 0$. If a storage capacity exists, then the demand/supply-side can – to a degree – be decoupled from the grid-side. The Power Node is coupled to the grid-side via the power consumption u_{load} and the power generation u_{gen}. The energy conversion processes have an efficiency η_{load} and η_{gen} respectively. All these energy flows will influence the dynamics of the Power Node storage level x.

Table 4 summarizes the type of Power Nodes that are employed for modeling generation, load and storage portfolios of each country's power system.

Table 4 – Power Node Unit Model Types for a Power System

General formulation:		$C_i\dot{x}_i = \eta_{load_i} u_{load_i} - \eta^{-1}_{gen_i} u_{gen_i} + \xi_i - w_i - v_i$	
Type	Properties	Equation	Decision Variable
T1 Load Demand	No Storage Profile Infeed Curtailable	$\eta_{load_i} u_{load_i} = w_i - \xi_i$	u_{load_i}, w_i
T2 Conventional Plants	No storage Fully Controllable	$\eta^{-1}_{gen_i} u_{gen_i} = \xi_i$	u_{gen_i}, ξ_i
T3 Variable RE Plant (include Run of River)	No load No storage Profile Infeed Curtailable	$\eta^{-1}_{gen_i} u_{gen_i} = \xi_i - w_i$	u_{gen_i}, w_i
T4 Hydro Reservoir	No load Large Storage Profile Infeed Curtailable	$C_i\dot{x}_i = -\eta^{-1}_{gen_i} u_{gen_i} + \xi_i - w_i$	u_{gen_i}, w_i
T5 Pump Storage	Load Storage No significant infeed	$C_i\dot{x}_i = \eta_{load_i} u_{load_i} - \eta^{-1}_{gen_i} u_{gen_i}$	u_{load_i}, u_{gen_i}

Each Power Node unit model type has a specific equation that describes its interactions with the electricity grid and the available decision variable for changing the power system unit's set-points. Figure 8 illustrates a part of the European power system representation as a set of interconnected Power Nodes. Every cluster of Power Nodes feeding to one bus represents the generation mix and load demand of the respective country (EU) or region (CH). The Power Nodes are interconnected via the so-called Net Transfer Capacity (NTC) values published by ENTSO-E. In the case of Switzerland, each modeling region is represented by a cluster of Power Nodes, defining its respective generation portfolio and load demand. The regions are interconnected via the aggregated thermal limits of the high-voltage transmission lines, as derived from detailed transmission grid models (Table 1, source: swissgrid)).

In the following, the mathematical formulation of the economic dispatch optimization that allows to perform an hourly predictive dispatch of the European power system is described.

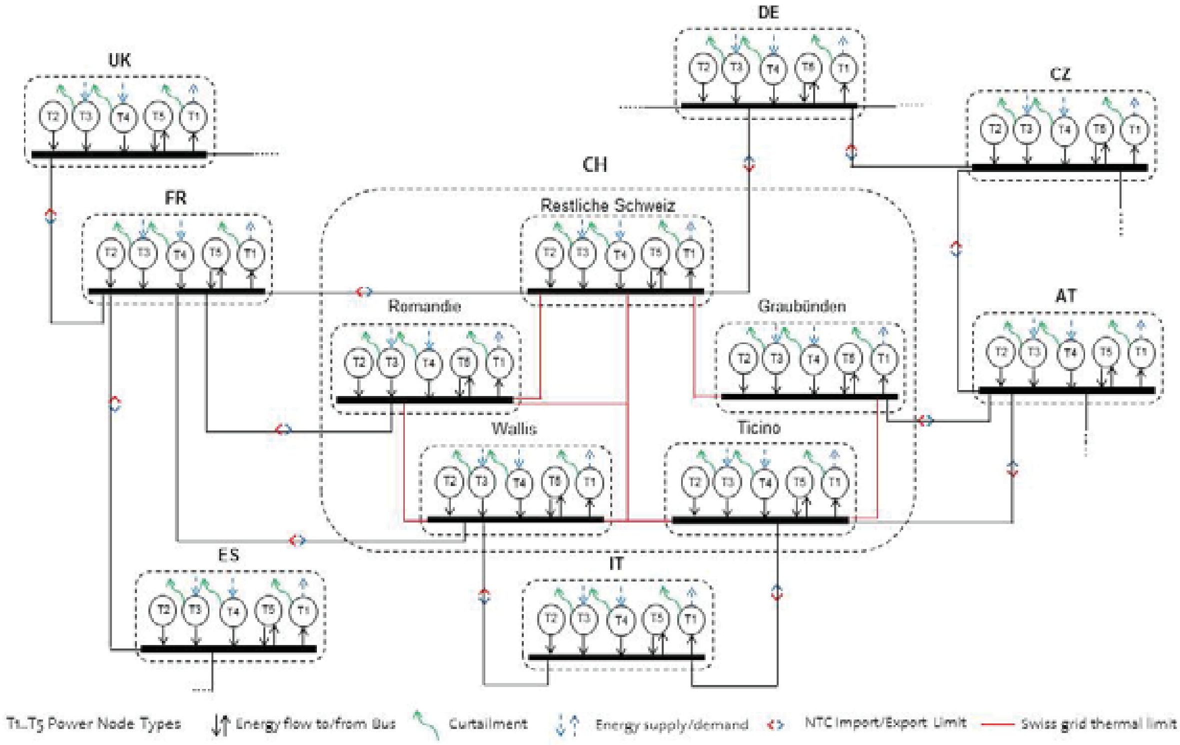


Figure 8 – System View of Power Node based Representation of the Detailed Swiss Power System Model (region-level) and Its European Neighbors (country-level).

2.5 Predictive Economic Dispatch Optimization

Today, the European Power System is operated based on the outcomes of the various regional and national power markets, e.g. power plant schedules derived from day-ahead and intra-day spot market auction results, as well as still significant bilateral short-term and long-term contracts. The market volumes of the different European spot markets, e.g. Nordpool and EPEX, have been steadily rising in past years [32]. The results of power market day-ahead and intra-day spot auctions are thus increasingly determining the European-wide power plant dispatch schedules.

Within spot market auctions, each power market participant runs a local optimization for his own unit portfolio, including its operational constraints, using the available intra-day and day-ahead forecast information for load demand, wind and PV power production and then submits corresponding auction bids. Day-ahead bids are submitted before noon; soon afterwards the day-ahead spot market is cleared. Since in reality there exist significant prediction errors for day-ahead load and RES production forecasts, most European power markets provide continuous intra-day spot market trading platforms that allow trade-based power generation and load demand schedule updates up to 45 minutes before the physical electricity delivery (EPEX). Since these updated dispatch schedules are still subject to some uncertainty, which could cause a mismatch between supply and demand of electricity, real-time power balancing is performed by activating control reserves, provided as so-called ancillary services (Systemdienstleistungen), to keep the power system stable.

To better understand the impacts of high production shares of fluctuating renewable electricity generation on power system operation, it is decisive to model and run the *simulated* power dispatch as close as possible to the *real-world* power dispatch of the power system in question. Since forecast information of load demand and RES power in-feed are in reality significantly influencing power market bidding strategies and power plant dispatch decisions, it is essential to build an optimization model that is able to explicitly use forecast data over a finite prediction horizon for its dispatch decision [33]. Moreover, it should allow for load demand and weather forecast updates as both the employed forecast horizon and the forecast accuracy plays a crucial role for power dispatch performance.

Figure 9 illustrates the Model Predictive Control (MPC) algorithm that is implemented in the predictive power dispatch scheme that has been developed by the Power Systems Laboratory (PSL) of ETH Zürich. The MPC-based predictive dispatch scheme solves the optimization problem in a receding horizon fashion, explicitly using the information of available load demand as well as wind and PV production forecasts. In Figure 9, the prediction horizon length is set to 24 hours ahead, which is the mean forecast horizon usually available in day-ahead spot markets.

The first horizon defines the forecast variables that are fed into the optimizer with the goal of minimizing the overall power system's operation cost (economic dispatch) over 24 hours. Only the first step of the derived optimal power dispatch schedule $\boldsymbol{u}^*$ is implemented, i.e. dispatched. The optimization problem is then updated, i.e. the prediction horizon length is shifted by one step receding into the future, and a new optimal power dispatch strategy $\boldsymbol{u}^*$ is calculated. Thereby, a closed-loop optimal power dispatch solution is found for every hour based on the day-ahead predicted load demand and RES power output time-series.

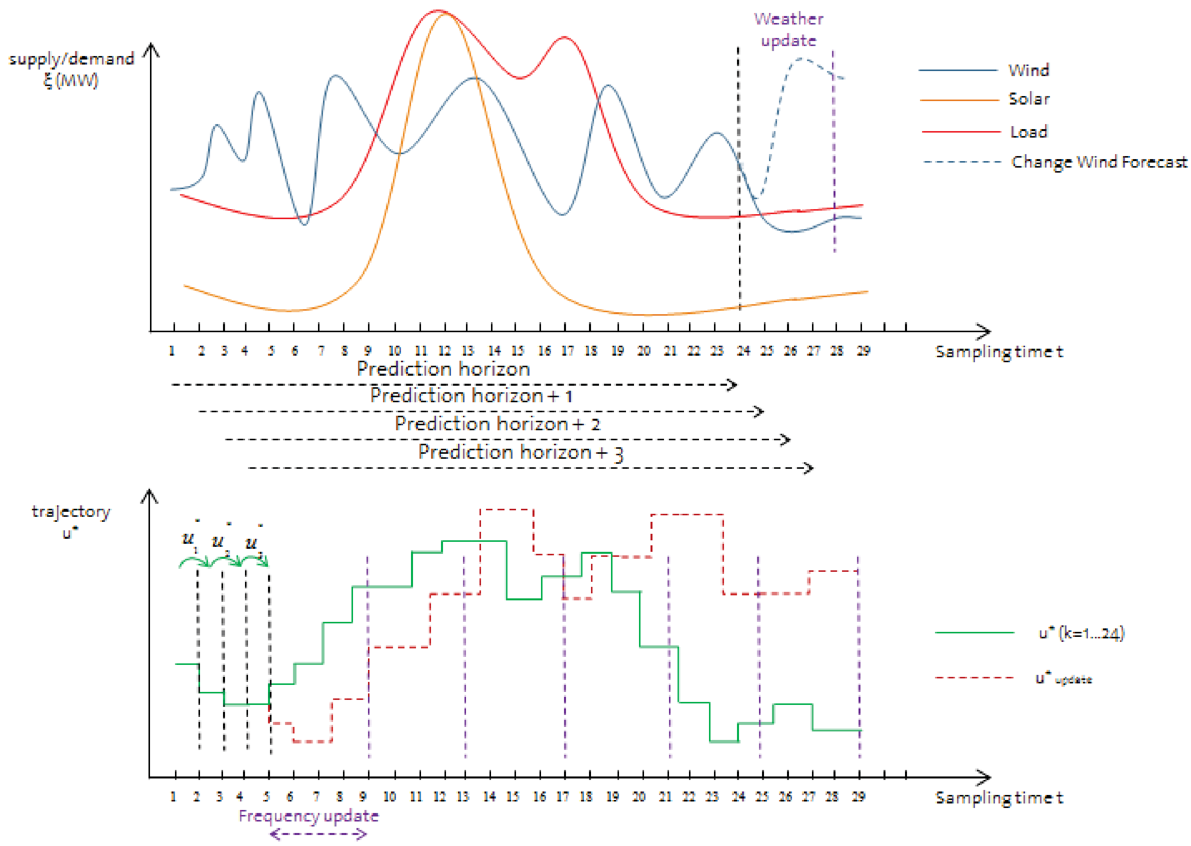


Figure 9 – Model Predictive Control Application in Power System Dispatch.

Due to this continuous shift of the prediction horizon, in essence an update incorporating newly available forecast information, the simulated predictive power dispatch scheme is arguably close to the functioning of a real-world power dispatch processes (assuming a competitive power market and implicit cross-border capacity auctions via market coupling). To counter forecast prediction errors, weather updates can be incorporated, thereby any change in predicted wind speeds or sun irradiation will be given as an input to the now current state, yielding a new dispatch strategy. Such optimization updates closely emulate the intra-day schedule updates. One observes the change from the green to red trajectory in Figure 9 after a forecast update (i.e. significantly higher future wind forecasts). In such a case, the new dispatch strategy discharges pump storage plants in order to later absorb the forecasted excessive wind power. The mathematical formulation of the optimization problem is further presented below. The objective function is constrained to physical and operational limits that derive from generating electricity, storing it or transmitting it. The predictive economic dispatch optimization problem, with objective to minimize the total operation cost of the European power system, is formulated as

$$\min_{u} J(t) = \sum_{l=t}^{l=t+N-1} u(l)^T \cdot Q_u \cdot u(l) + R_u \cdot u(l) + \delta u(l) \cdot \delta Q_u \cdot \delta u(l)$$

$$\begin{array}{lll}
\text{s.t.} & (a) & x(l+1) = A \cdot x(l) + B \cdot u(l) \\
 & (b) & 0 \leq x^{min} \leq x(l) \leq x^{max} \leq 1 \\
 & (c) & 0 \leq u^{min} \leq u(l) \leq u^{max} \leq 1 \\
 & (d) & 0 \leq \delta u^{min} \leq \delta u(l) \leq \delta u^{max} \leq 1 \\
 & (e) & \xi(l) \Big|_{i=1,2,3,4,5,6,7} = \xi_{drv}(l,T) \Big|_{i=1,2,3,4,5,6,7} \\
 & (f) & \sum u_{gen,j}(l) - \sum u_{load,j}(l) = \sum NTC_{j->k} - \sum NTC_{k->j} \\
 & (g) & 0 \leq P_{j->k} \leq NTC_{j->k} \\
 & (h) & 0 \leq P_{k->j} \leq NTC_{k->j} \\
 & (a-h) & \forall l = \{t, \ldots, t+N-1\}
\end{array}$$

where x_l represents the state of charge of storage-units and u_l is the power nodes in/out-feed for prediction time step *l*. R_u, Q_u, and δQ_u represents linear and quadratic marginal as well as ramping cost terms, respectively. Sampling time t is one hour and the prediction horizon N is set to 24 hours.

The system is composed of 33 interconnected buses (EU-27 + Norway + 5 Swiss regions), with up to 15 Power Nodes per country/region bus and two decision variables per power node. Therefore, each optimization step consists of finding the least cost dispatch of 990 (33x30) variables such that the above constraints are satisfied over the prediction horizon. Constraint (a) expresses the discretized set of the system of linear Power node equations that can be derived from Table 4 (refer also to [20]), (b-d) are constraints on the state, output and rating output of a plant, (e) represents the exogenous profile constraints of power nodes $i = \{1\ldots. 7\}$, (f) is the power balance of each country *j* which is equal to its to the sum of the net exchanges of power with all interconnected countries *k*, (g-h) the import/export NTC constraints of the respective transmission corridors.

The terms *j* and *k* are a set of indices in a 33x33 grid topology matrix that was built based on the European grid topology, published by ENTSO-E in [3] and the regional aggregated Swissgrid topology. To control the decision of shedding load, curtailing renewable output or ramping conventional generators, a cost is assigned to these actions using the penalty factors Q_u, R_u and δQ_u. For more information regarding the MPC strategy and the costs associated to the penalty factors, please refer to [20].

2.6 Key Characteristics of All Performed Power System Simulations

- All simulation results derive from full-year simulations of the combinations of the different electricity supply&demand scenarios with an hourly time-resolution (8'760 time-steps per simulation year).
- A predictive power dispatch optimization is performed based on the marginal operation costs for all power plant and hydro storage units including relevant inter-temporal constraints (power ramping and energy constraints) as well as grid constraints of the interconnected European Power System.
- Wind turbine and PV units have no marginal generation costs (no fuel costs). At the same time curtailment of RES generation (wind, PV and run-of-river hydro) is penalized, in line with RES in-feed regulations in many European countries. RES curtailment is thus an option of last resort for balancing electricity supply & demand.
- Since all production cost assumptions beyond a ten-year time-frame are – at best – informed guesses, we have simplified the matter and assume that the marginal generation costs are fixed to the values of the reference year 2020 also for all simulations years till the reference year.
- All fluctuating RES generation is dispatched first (due to the zero or very low marginal cost), whereas all thermal plants and hydro storage units follow (in the order of the respective marginal fuel costs per MWh_e power output).
- As stated in the ENTSO-E ten-year development plan (TYNDP), the Net Transfer Capacity (NTC) values of Switzerland with its neighbors are, for the time being, not subject to be increased. Thus the existing NTC values (year 2010) for the cross-border transmission corridors around Switzerland are employed in all dispatch simulations. Please note that this as a rather conservative modeling choice that limits possible electricity imports&exports of the Swiss Power System. Other transmission corridors in parts of the European system are however upgraded to higher NTC ratings in the coming years as the result of cross-border grid expansion projects.
- The above described economic dispatch optimization setup allows to determine the technical limit of the Swiss power system in integrating fluctuating RES electricity generation. From an environmental perspective, such a dispatch setup minimizes overall CO_2 emissions.

3 Results and Discussion

In the following, we compare our theoretical dispatch results to real-world dispatch measurements to show and discuss the validity of the Power Nodes-based European power system model and the predictive power dispatch scheme and analyze the impacts of the BFE Energy Strategy 2050 on the Swiss power system.

3.1 Simulation versus Real-World Dispatch Results (Year 2010)

The Power Nodes predictive power dispatch results are compared with the actual yearly Swiss power dispatch results, as published by the BFE Electricity Statistics [23] (annual electricity balance), and with the actual hourly power exchanges of Switzerland with its neighboring countries, as published by swissgrid, both for the reference year 2010.

Furthermore, the power dispatch statistics of all European countries for the year 2010, as found in the IEA electricity report [28], are compared to the simulation results. In addition, the simulated annual CO_2 emissions from the electric power sector of each country are compared to the IEA reference values found in [34].

3.1.1 Switzerland

In a first step the simulated production shares of electricity generation per technology in Switzerland are almost identical to the actual BFE statistics for the year 2010 (Fig. 10)

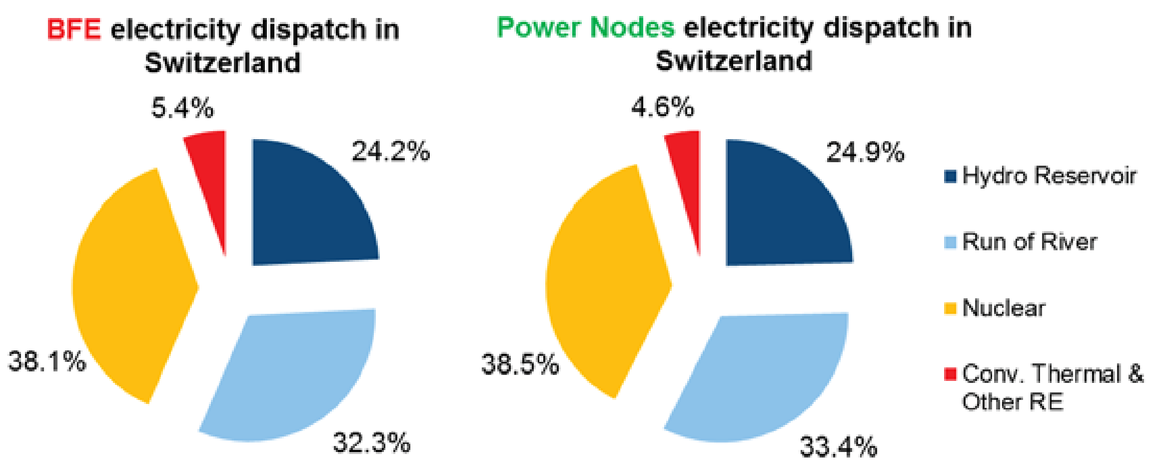


Figure 10 – BFE measurements [23] vs Power node dispatch in Switzerland in 2010.

In a second step the actual Swiss country balance obtained from swissgrid measurements to our power node model dispatch. The country balance is the total amount of electricity imported or exported at each hour during the year.

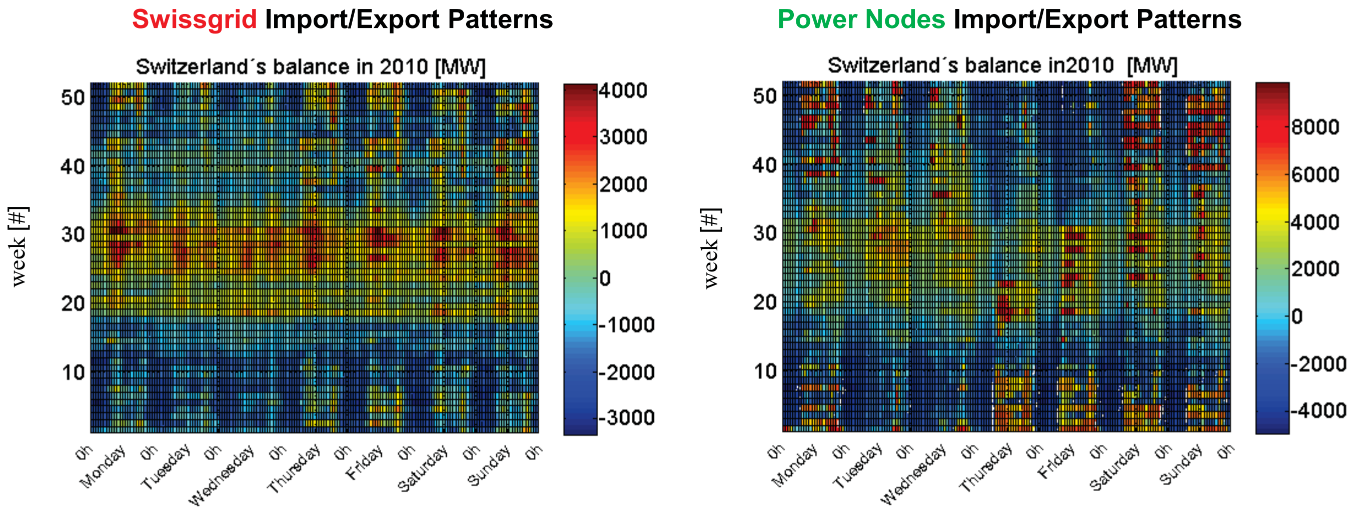


Figure 11 – Power Exchange Patterns: swissgrid Statistics and Power Node Simulations.

Publicly available statistics by swissgrid show that the actual import/export balance of Switzerland ranged from about 3.5 GW of electricity import during the winter season to about 4 GW of electricity export at daytime during the summer season. A weekly pattern is visible in the horizontal direction, which indicates that Switzerland's load demand during nighttime is lower than during daytime. In the summer months, cross-border transmission lines are more loaded at noon (i.e. exporting electricity at high prices), while in the winter months they are more loaded during the night (i.e. importing electricity at low prices). A seasonal pattern in the vertical direction can be recognized which indicates that Switzerland is a net importer during wintertime (i.e. high load demand) and a net exporter during summertime (i.e. high water inflow into storage lakes and run-of-river plants due to snow melting and rain). Overall, Switzerland imported 32.9 TWh_e/a and exported 30.9 TWhe/a in the reference year 2010.

The Power Node dispatch results showed *qualitatively* similar horizontal load patterns (weekly profile) as well as vertical load patterns (seasonal profile). However, *quantitatively* it can be clearly seen that higher peak power exchanges occur in the simulation than actually achieved in the year 2010. This more aggressive grid usage is both visible for imports as well as exports. The simulated import/export balance of Switzerland ranged from about 4.5 GW of electricity import during the winter season to about 9 GW of electricity export at daytime during the summer season.

As the theoretical sum of the export Net Transfer Capacities (NTC) values from Switzerland to its neighbors are given as about 10 GW, whereas import NTC values to Switzerland are given as about 7 GW (as assessed by ENTSO-E: indicative values for NTC, Summer and Winter 2010), the simulated more aggressive power dispatch patterns would be within the nominal import/export bounds.

In the Power Nodes dispatch mode, the cost of transmitting electricity (i.e. grid fees) is not considered. Also, as in most European power market schemes, the assumption is taken that there are no congestions inside each country node (i.e. market zone). According to simulated dispatch results, Switzerland imported 30.2 TWhe and exported 36.6 TWhe in the reference year 2010.

The discrepancy in the peak electricity import/export values between simulation and reality can be explained by the effects of several (unavoidable) gaps between the simulated and the actual European power system, i.e.

1. **Perfect market assumption in the simulations**, i.e. all electricity generation is traded on spot markets using a Europe-wide market coupling. This is in obvious contrast to the still fragmented European power markets and other imperfections (i.e. explicit auction of cross-border capacities in Switzerland, no Europe-wide market dispatch, significant over-the-counter bilateral trading as well as still existing long-term contracts).
2. **Necessary modeling simplifications**, i.e. not all relevant modeling parameters of the European power system are publicly available today. This includes, for example, the subtle differences of generation and fossil fuel costs in the different European countries, the lack of publicly available accurate models of the European transmission grid as well as the lack of detailed maintenance schedules of all large European power plants (1000+ units).

In light of this, please note that, first, power systems are considered to be the by far most complex man-made systems, and that, second, the European power system is one of the largest interconnected grids worldwide with several thousand large and several million small power plant units. Perfectly modeling such systems trying to include all details would be a time-consuming (and eventually pointless) endeavor, while perfectly simulating such systems would be a doubtful claim.

This study tries to accurately model the functioning of the European power system on a highly aggregate level (based on countries [EU] and large regions [CH]) and to plausibly simulate the behavior of the European power system for different electricity supply and demand scenarios, analyzing in particular the impacts on the Swiss power system.

Figure 12 illustrates the optimal dispatch of the Swiss power system in 2010 obtained with the power node model. Figure 13 is a zoom-in representation of the month of June 2010. The first sub-plot indicates the hourly generation mix (above the x-axis) that is dispatched to satisfy the hourly varying load demand (below the x-axis). Nuclear power plants (orange) are inflexible and are dispatched most of the time as base load generation. The production variations in summer are due to known nuclear plant maintenance windows (BFE).

The light blue curve represents hydro run-of-river production, which is more important in summer than in winter due to snow melting and rain patterns. The hydro reservoir production is a mix of operation between controllable generation with a storage capacity and non-controllable but curtailable generation. The overall Swiss reservoir energy storage capacity is about 8’780 GWh, whereas the yearly production of hydro reservoirs plants in Switzerland is about 20’000 GWh [23]. The amount of water that was actually accumulated in the storage lakes this year was, however, only about 6’979 GWh [23]. This means that 13’462 GWh were directly channeled through the reservoirs, rendering this part of the storage lake generation quite similar to the production profile of run-of-river plants.

Hereby, in Fig. 12–13, appear two plots for the hydro reservoirs production, the blue curve that is dispatched as run-of-river plants and the dark blue curve that is dispatched as a storage lake hydro reservoir, which generates electricity only when it is needed. The magenta curve on top and bottom of the x-axis represents the operation of pump storage plants. We can observe in the first sub-plot of Fig. 13 that PHSs are pumping during the night (below x-axis) and turbining during the day (above x-axis), which qualitatively reflects the pump storage hydro operation patterns of the reference year 2010.

The second sub-plot in both Fig. 12–13 illustrates the curtailment of variable energy supply (Wind, Solar, Hydro) and load. In the reference year 2010, according to the Power Node dispatch, the Swiss power system was able to fully integrate all RES generation and cover the load demand all year long. The third sub-plot indicates the storage levels of hydro reservoirs and pump storage plants in Switzerland. Important to notice is the evolution of the storage level of the hydro reservoirs, which is in line with the BFE historical variation of storage levels in Switzerland [5]. The fourth sub-plot indicates the hourly net balance of Switzerland with its neighbors. From May to August, Switzerland is almost every hour a net exporter, since this time period corresponds to large water influx from both snow melting and rain fall.

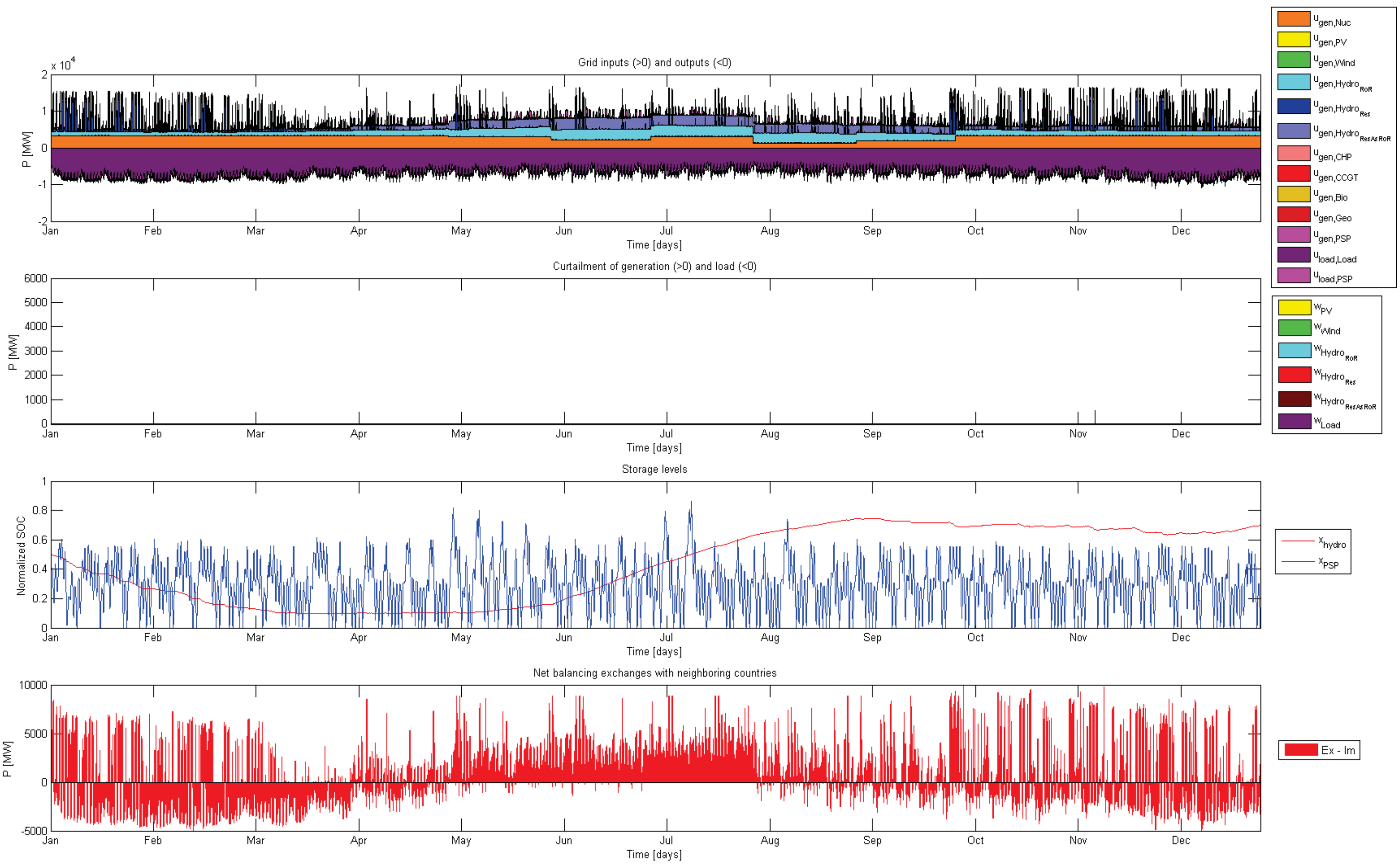


Figure 12 – Economic Dispatch of the Swiss Power System (full-year 2010).

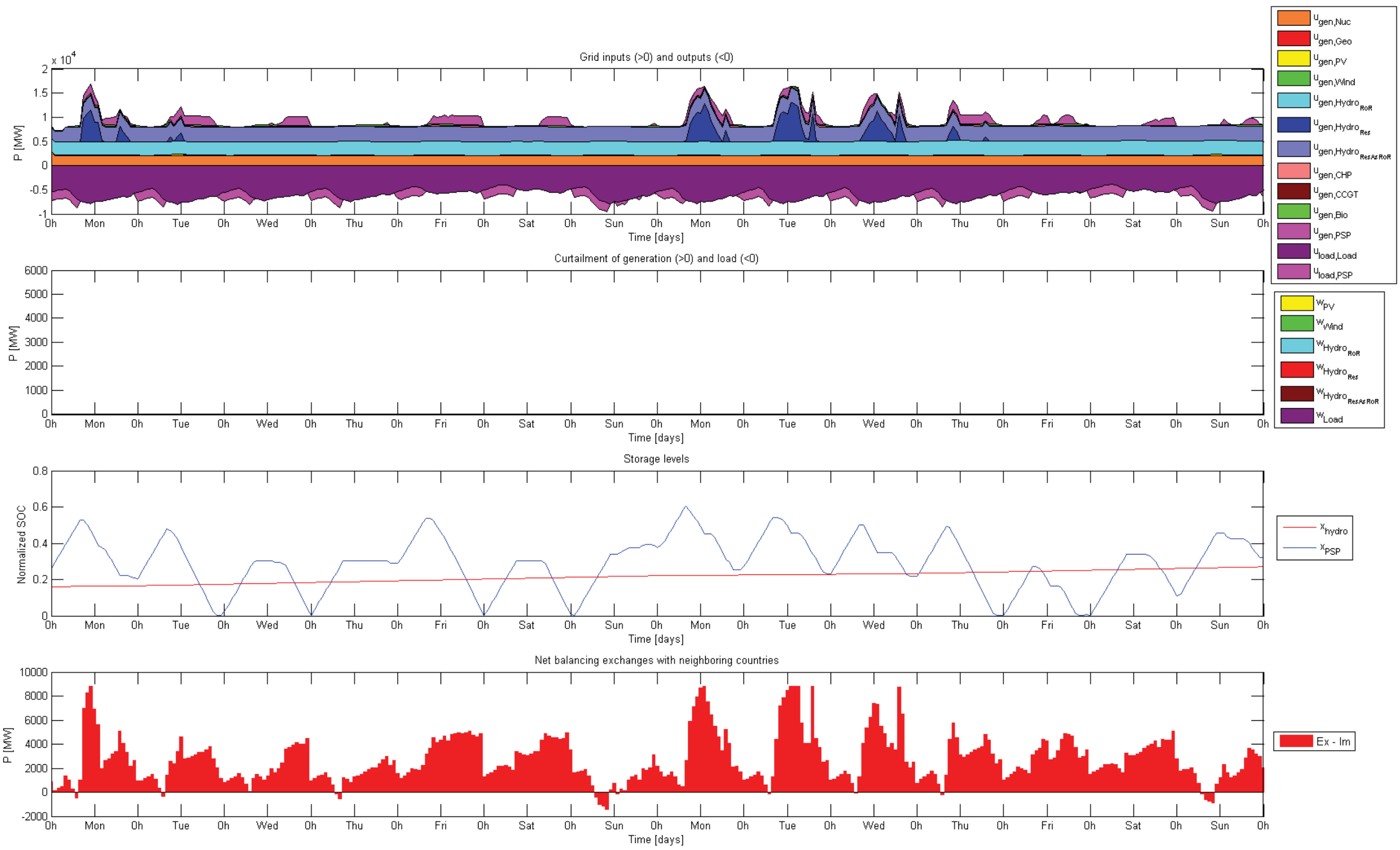


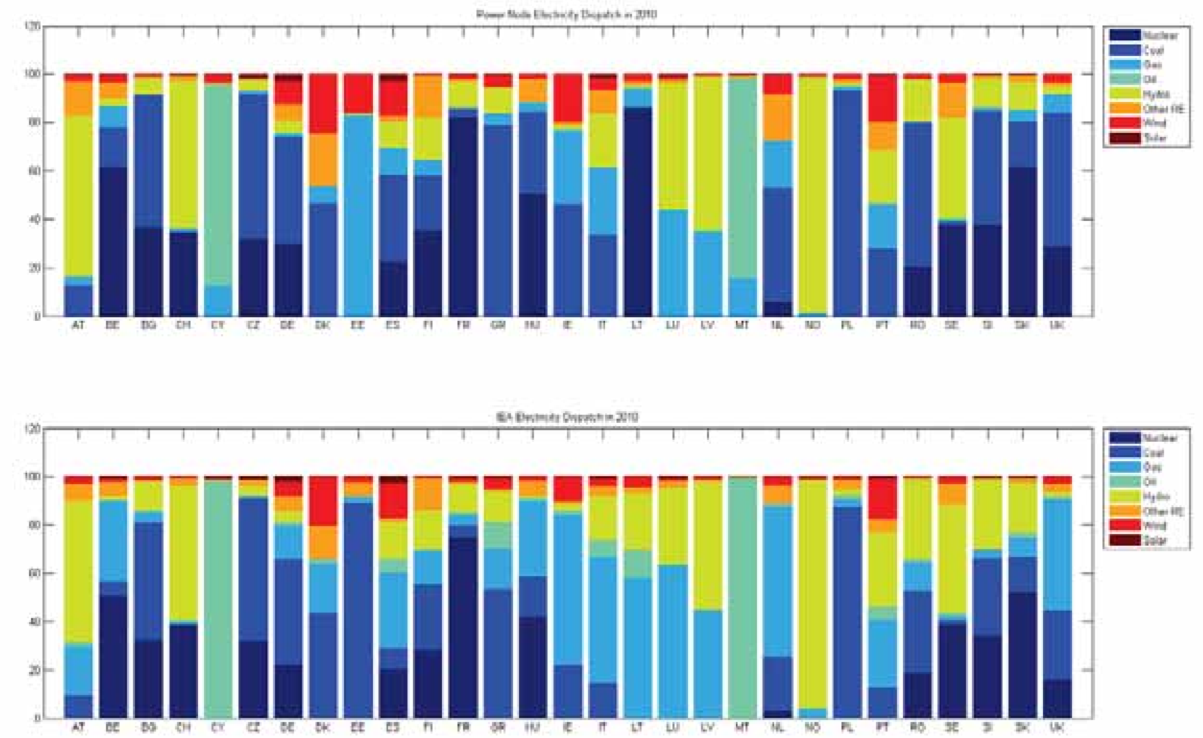
Figure 13 – Economic Dispatch of the Swiss Power System (31 May – 13 June 2010).

3.1.2 Europe–27

In Fig. 14 the power node dispatch results for each European country are compared to the IEA electricity statistics for the reference year 2010.

Figure 14 shows the plausibility of Power Nodes dispatch model as the relative error per country between the total amount of energy generated in reality compared to the power dispatch simulation results differs by only 3%. However, some country balances do significantly vary such as for the Netherlands as well as the Baltic countries.

Please note that for the case of the three Baltic countries there are well-known flaws in the available statistical data Lithuania. For instance, the IEA statistics state that there was no electricity produced from nuclear power plants in 2010 in Lithuania, whereas 1.1 GW of nuclear power plant capacity was effectively installed there according to EURELECTRIC.



	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	IE
IEA Net Production (TWh)	68.6	91	43	66	5	79.5	596	36.8	12.9	291	77.2	545	53	34.6	26.8
Power Nodes Simulation Generation (TWh)	70	81	44	65	4.9	99	578	38	2.22	278	60.3	606	59	32.2	24.9
Source: IEA, Eurostat	2%	-11%	2%	-2%	-2%	25%	-3%	3%	-83%	-4%	-22%	11%	10%	-7%	-7%

	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK	UK	Total
IEA Net Production (TWh)	291	6.6	4.6	5.7	1.99	114	123	143	52.8	57.8	145	15.4	25.4	366	3380.39
Power Nodes Simulation Generation (TWh)	231	14.2	3.77	9	2	65	121	140	46.5	56	144	15	24	357	3270.59
Source: IEA, Eurostat	-21%	115%	-18%	58%	1%	-43%	-2%	-2%	-12%	-3%	-1%	-3%	-6%	-2%	-3%

Figure 12 – European Power Node Dispatch Results versus IEA statistics for Reference (2010).

CO_2 emissions are a significant result in the post-processing part of the power dispatch simulations and have to be in line with the actual CO_2 statistics in order to further validate the power system model and the simulated power dispatch process. Based on [34], we assign the specific CO_2 emissions emitted per MWhe of electricity produced for each type of power plant [1]. Figure 15 illustrates the CO_2 emissions emitted from the power sector of each European country in the reference year 2010 according to IEA statistics and the simulated dis-

[1] Coal: 0.92 tonne CO_2/MWh_e, Oil: 0.62 tonne CO_2/MWh_e, Natural Gas: 0.37 tonne CO_2/MWh_e.

patch results. The CO_2 emission quantities per country using the Power Node dispatch (red curve) are generally in line with the IEA statistics (black curve) [34]. The overall CO_2 emissions from the EU power sector were 1.3 billion tons in the year 2010 according to the IEA and about 1.05 billion tons according to the Power Node dispatch for that same reference year (due to higher natural gas and, consequently lower coal usage, as well as statistical differences when considering brut load demand [IEA statistics] and net load demand [simulation]). The simulated dispatch results notably well captured the highest polluting EU countries, i.e. Germany, United Kingdom and Poland.

Based on the results shown in this section, we have cross-checked and validated the Power Nodes power system model and the predictive power dispatch process for the European Power System against various statistical data sources, showing the plausibility of the simulation results, while explicitly discussing the existing differences and gaps of the modeling and simulation approach.

With these modeling and simulation models, we can in our opinion – sufficiently – accurately analyze the impact of the BFE Energy Strategy 2050 for the Swiss power system under the various electricity supply & demand scenarios. Of course, a simple model can only capture the rather complex dynamics of the European Power System only to a certain point and can thus only be used for answer questions whose analysis can be performed with the modeling and simulation tools at hand. We believe that this is the case for the analysis performed in the following sections.

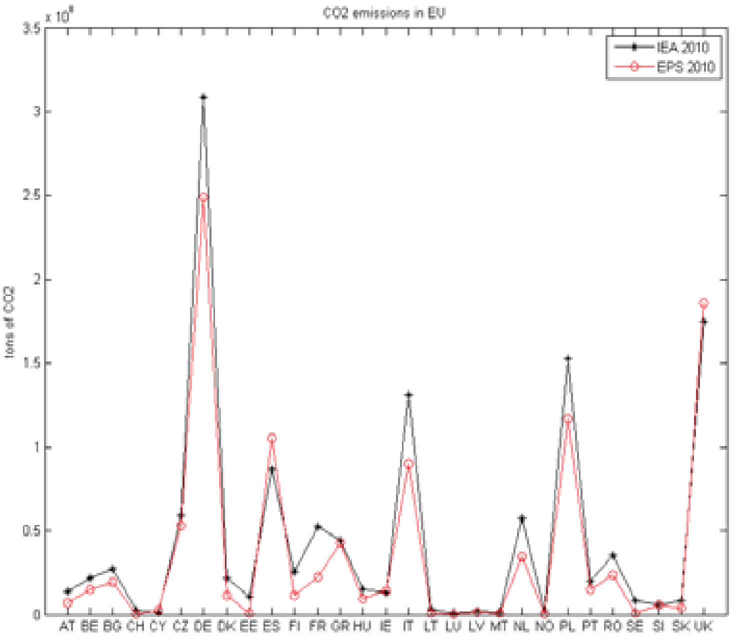


Figure 15 – CO_2 Emissions of Electric Power Sector: Power Node Simulations versus IEA Statistics (Year 2010).

3.2 Impact of BFE Energy Strategy 2050 on Switzerland

3.2.1 BFE Energy Strategy in Short

In a nutshell, the BFE's energy strategy until the reference year 2050 is to replace the currently existing 3.3 GW of nuclear power capacity in Switzerland by large RES shares (i.e. up to 9 GW of photovoltaic (PV) panels, 2 GW of wind turbines, 0.5 GW of geothermal power plants, an additional 0.4 GW of combined heat and power (CHP) plants and 0.3 GW of biomass plants); with the option to build up to 2.8 GW of gas turbine power plant capacity in some supply scenarios.

Also, up to 4 GW of additional pump storage power capacity is planned to be added by the time-period 2020-25 (see Fig. 16).

Projektname	Kapazität turbinenseitig [MW]	Berücksichtigt im Modell ab dem Jahr
Veytaux (FMHL+)	240	2015
Grimsel 3 (KWOplus)	660	2020
Nant de Drance	900	2018
Linthal 2015	1000	2017
Lagobianco	1000	2025

Quelle: Frontier

Figure 16 – BFE Assumption of Realized Pumped Hydro Storage Capacities (taken from „Bewertung von Pumpspeicherkraftwerken in der Schweiz im Rahmen der Energiestrategie 2050“, Studie für das Bundesamt für Energie (BFE) – Schlussbericht“ (Annex 1, Table 4).

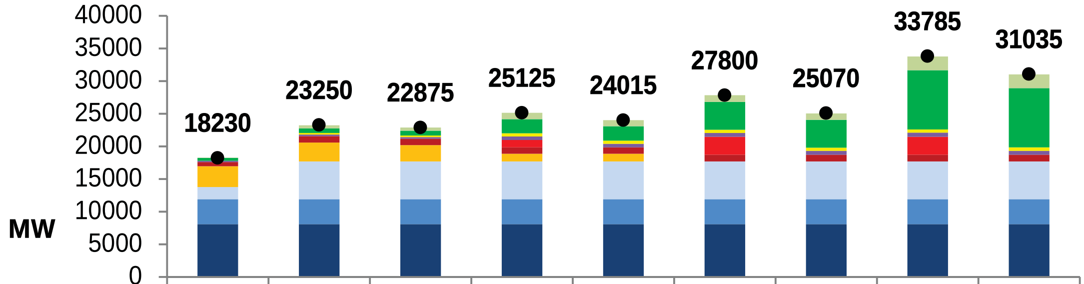
It is projected by BFE/Prognos that 9 GW of installed PV capacity in Switzerland will generate about 11.2 TWh per year and 2 GW of installed wind turbine capacity will generate about 4.2 TWh per year. Figure 17 – BFE supply scenarios: the power plant illustrates the phase-out of nuclear power plant capacities in Switzerland per decade and its planned replacement.

Our analysis consists of simulating the power dispatch of such a generation mix with the Power Node dispatch model; analyzing the different impacts of each BFE supply and demand scenario as well as the IEA demand scenario (+50% electricity demand) and a supply scenario with significantly higher PV energy shares on power system operation.

3.2.2 BFE Energy Strategy: Scenario Results

The simulation results show that for the BFE business-as-usual (WWB – “Weiter Wie Bisher”) scenario with an assumed electricity consumption that increases by about 17% from 2010 to 2050, the Swiss power system would be able to absorb 100% of the available fluctuating electricity supply (11 TWh PV, 4.2 TWh Wind, 38 TWh Hydro) in the reference year 2050.

In the BFE efficiency scenario (POM – “Politische Massnahmen”) in which the electricity consumption stays roughly constant, 5% of available RES electricity supply in Switzerland could not be grid-integrated. No load shedding occurred and the loading of the lines connecting Switzerland with its neighbors did not significantly increase.



	2012	2020 Var C&E	2020 Var E	2030 Var C&E	2030 Var E	2035 Var C&E	2035 Var E	2050 Var C&E	2050 Var E
Wind	42	485	485	940	940	1000	1000	2130	2130
PV	436	700	700	2170	2170	4270	4270	9070	9070
Geothermal	0	250	250	500	500	500	500	500	500
Biomass	240	240	240	530	530	590	590	625	625
Gas	0	0	0	1110	0	2750	0	2750	0
Thermal WKK	600	1000	1000	1000	1000	1000	1000	1000	1000
Nuclear	3220	2855	2490	1165	1165	0	0	0	0
Pump storage	1840	5790	5790	5790	5790	5790	5790	5790	5790
Hydro Run of river	3840	3840	3840	3840	3840	3840	3840	3840	3840
Hydro Reservoirs	8080	8080	8080	8080	8080	8080	8080	8080	8080
● Total	18230	23250	22875	25125	24015	27800	25070	33785	31035

Figure 17 – BFE supply scenarios: the power plant capacities.
* 3300 MW for the Business As Usual scenario ~ 6 gas turbine power plants

According to the dispatch results for the reference year 2010, the Swiss cross-border transmission corridors were, on a yearly average, 43 % of the time fully loaded at the nominal net transfer capacity (NTC) value[2]. In the BFE scenario with no gas power plants, electricity imports had to contribute more to the energy mix. Our simulation results show that even with currently existing cross-border transfer capacities that are connecting Switzerland to its neighbors (reference year 2010), the higher electricity imports predicted for the year 2050 could safely be satisfied. The yearly average full loading of the lines would increase somewhat (to about 55%), allowing higher net imports during the winter season (increase by 16%, compared to 2011 [5 TWh, swissgrid]). Table 4 and Table 5 summarize the dispatch results for the POM scenario with gas-fired CCGT (GuD) plants and Renewables (C&E) and only renewable energies (E), and the WWB scenario with the C&E supply scenario.

[2] The Net Transfer Capacities (NTC) between countries are determined by the ENTSO-E to allow for a safe exchange of power that does not compromise the security of the system. This includes various security considerations, including N-1calculcations. In theory, the lines could be loaded all year at their full NTC values.

Table 5 – BFE POM Scenario

Parameter Analyzed	2010	2020		2030		2035		2050	
	-	Var C&E	Var E	Var C&E	Var E	Var C&E	Var E	Var C&E	Var E
Energy demand (TWh)	58.52	60.37	60.37	58.17	58.17	58.00	58.00	60.57	60.57
PV available (TWh)	0.32	0.52	0.52	1.91	1.91	3.18	3.18	11.12	11.12
PV int (%)	100%	100%	100%	100%	100%	100%	100%	94%	94%
Wind available (TWh)	0.07	0.66	0.66	1.46	1.46	1.61	1.61	4.26	4.26
Wind int (%)	100%	98%	98%	0.99	99%	1.00	100%	0.96	96%
Variable Hydro (TWh)	29.66	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50
Var-Hydro int (%)	100%	99%	99%	100%	100%	100%	100%	95%	95%
RES available (TWh)	30.05	31.68	31.68	33.87	33.87	35.28	35.28	45.88	45.88
RES integration (%)	**100%**	**99%**	**99%**	**100%**	**100%**	**100%**	**100%**	**95%**	**95%**
Demand covered by var-RES (%)	**51%**	**52%**	**52%**	**58%**	**58%**	**61%**	**61%**	**72%**	**72%**
Biomass (TWh)	1.66	1.90	1.89	4.39	4.36	4.85	4.86	4.55	4.56
Geothermal (TWh)		2.19	2.19	4.36	4.36	4.36	4.36	4.28	4.28
Dispatchable Hydro reservoirs (TWh)	8.22	12.35	12.35	11.86	11.97	6.42	7.14	5.84	6.83
Demand covered by dis-RES (%)	**17%**	**27%**	**27%**	**35%**	**36%**	**27%**	**28%**	**24%**	**26%**
GuD generation (TWh)		0.00	0.00	3.08	0.00	7.80	0.00	7.37	0.00
GuD capacity factor (%)				**32%**		**32%**		**31%**	
CHP generation (TWh)	0.95	5.54	5.54	5.71	5.77	5.67	5.86	5.22	5.35
Nuclear generation (TWh)	24.93	20.51	20.51	9.55	9.55	0	0	0	0
Demand covered by Conv.Supply (%)	**44%**	**43%**	**43%**	**32%**	**26%**	**23%**	**10%**	**21%**	**9%**
Winter Imports (TWh)	15.78	15.64	15.64	14.45	15.32	15.95	17.87	15.89	17.72
Winter Exports (TWh)	14.57	16.22	16.22	16.26	14.67	14.63	11.24	14.76	11.91
Winter Net balance (TWh)	1.21	-0.59	-0.58	-1.80	0.65	1.33	6.63	1.13	5.81
Winter Demand (TWh)	31.76	31.72	31.72	31.57	31.57	31.48	31.48	32.87	32.87
Winter Demand covered by imports (%)	**4%**	**-2%**	**-2%**	**-6%**	**2%**	**4%**	**21%**	**3%**	**18%**
Summer Imports (TWh)	14.39	13.50	13.50	13.22	13.41	14.90	15.54	13.17	13.73
Summer Exports (TWh)	22.04	24.31	24.31	23.76	23.46	20.26	19.41	22.03	21.05
Summer Net balance (TWh)	-7.64	-10.82	-10.82	-10.54	-10.06	-5.36	-3.87	-8.85	-7.32
Summer Demand (TWh)	26.76	28.65	28.65	**26.61**	26.61	**26.53**	26.53		27.70
Summer Demand covered by imports (%)	**-29%**	**-38%**	**-38%**	**-40%**	**-38%**	**-20%**	**-15%**	**-32%**	**-26%**
Total Imports (TWh)	30.17	29.13	29.13	27.67	28.72	30.86	33.41	29.07	31.45
Total Exports (TWh)	36.60	40.54	40.53	40.02	38.14	34.89	30.65	36.79	32.96
Total Net balance (TWh)	-6.43	-11.41	-11.40	-12.35	-9.41	-4.03	2.75	-7.72	-1.51
Total Demand covered by imports (%)	**-11%**	**-19%**	**-19%**	**-21%**	**-16%**	**-7%**	**5%**	**-13%**	**-2%**
PSP Number of Full Cycles per year	**94**	**238**	**238**	**244**	**242**	**261**	**252**	**287**	**283**
CO_2 emissions (million metric tons)	**0.59**	**3.43**	**3.43**	**4.68**	**3.58**	**6.40**	**3.63**	**5.96**	**3.32**
Yearly full load usage of NTC for cross border lines	45%	54%	54%	50%	50%	49%	51%	54%	55%

Table 6 – BFE WWB Scenario

Parameter Analyzed	2010	2020	2030	2035	2050
	-	Var C&E	Var C&E	Var C&E	Var C&E
Energy demand (TWh)	58.52	57.1	63.31	64.17	68.78
PV available (TWh)	0.32	0.52	1.91	3.18	11.12
PV int (%)	100%	100%	100%	100%	99%
Wind available (TWh)	0.07	0.66	1.46	1.61	4.26
Wind int (%)	100%	99%	0.99	0.99	0.99
Variable Hydro (TWh)	29.66	30.50	30.50	30.50	30.50
Var-Hydro int (%)	100%	99%	99%	100%	99%
RES available (TWh)	30.05	31.68	33.87	35.28	45.88
RES integration (%)	**100%**	**99%**	**99%**	**100%**	**99%**
Demand covered by var-RES (%)	**51%**	**55%**	**53%**	**55%**	**67%**
Biomass (TWh)	1.66	1.90	4.46	5.01	5.23
Geothermal (TWh)		2.18	4.36	4.36	4.36
Dispatchable Hydro reservoirs (TWh)	8.22	8.63	10.77	8.62	6.03
Demand covered by dis-RES (%)	**17%**	**22%**	**31%**	**28%**	**23%**
GuD generation (TWh)		1.93	8.67	15.87	16.22
GuD capacity factor (%)		**40%**	**45%**	**47%**	**56%**
CHP generation (TWh)	0.95	5.40	6.18	6.44	6.45
Nuclear generation (TWh)	24.93	20.52	9.62	0	0
Demand covered by Conv.Supply (%)	**44%**	**49%**	**39%**	**35%**	**33%**
Winter Imports (TWh)	15.78	14.86	14.30	13.95	12.91
Winter Exports (TWh)	14.57	17.86	16.52	16.39	14.42
Winter Net balance (TWh)	1.21	-3.00	-2.23	-2.44	-1.51
Winter Demand (TWh)	31.76	29.32	34.36	34.82	37.33
Winter Demand covered by imports (%)	**4%**	**-10%**	**-6%**	**-7%**	**-4%**
Summer Imports (TWh)	14.39	13.78	13.48	14.43	11.40
Summer Exports (TWh)	22.04	23.60	23.48	21.16	23.00
Summer Net balance (TWh)	-7.64	-9.82	-10.00	-6.72	-11.60
Summer Demand (TWh)	26.76	27.78	**28.96**	**29.35**	
Summer Demand covered by imports (%)	**-29%**	**-35%**	**-35%**	**-23%**	**-37%**
Total Imports (TWh)	30.17	28.64	27.78	28.38	24.31
Total Exports (TWh)	36.60	41.46	40.01	37.55	37.42
Total Net balance (TWh)	-6.43	-12.82	-12.23	-9.16	-13.11
Total Demand covered by imports (%)	**-11%**	**-22%**	**-19%**	**-14%**	**-19%**
PSP Number of Full Cycles per year	**94**	**240**	**241**	**241**	**247**
CO_2 emissions (million metric tons)	**0.59**	**4.06**	**7.04**	**9.87**	**10.00**
Yearly full load usage of NTC for cross border lines	45%	53%	51%	49%	44%

In both scenarios, common points can be drawn from Table 5 and 6:

- The pumped hydro storage plants are cycled more often with increasing renewable energy shares.

- Expanding the pumping capacity from 1.8 GW in 2010 to 5.7 GW by 2020-25 is worthwhile as the pumped-storage usage, i.e. the number of times the reservoirs are emptied and filled again (full cycle), would increase by a factor of about 2.5.
- If Combined-Cycle Gas Turbines (CCGT/GuD) power plants are not installed, CO_2 emissions from the Swiss electricity sector will increase by a factor of 5 compared to 2010 levels. If CCGT plants were installed, CO_2 emissions would increase by a factor of 16.
- The 2010 cross-border transfer capacities of Switzerland are loaded at full capacity between 45% and 55% in each decade.

The main difference between the WWB and POM scenarios are:

- CCGT plants would have significantly lower full-load hours over the year (40% less) in the POM scenario than in the WWB scenario.
- Switzerland would become a net electricity exporter also during the winter season in the WWB scenario when the 3.3 GW of nuclear power plants would be fully replaced by 3.3 GW of gas-fired power plants. In the WWB scenario, winter exports would amount to about 4% of winter demand in the reference year 2050 (Table 6, Var C&E).
- Switzerland would become a significant net electricity importer during the winter season in the POM scenario, ranging from winter imports of 3% (Var C&E) to 18% (Var E) of winter demand for the reference year 2050 (Table 5).

Please note that a significant degree of freedom, and hence operational flexibility, exists for the seasonal management of the storage lake units. The seasonal electricity import and export balances (winter and summer season) can be significantly altered in case the storage lake basins are managed more conservatively, i.e. keeping more water in the basins during the winter season as an energy reserve and consequently increasing winter imports, or less conservatively, i.e. almost emptying the storage lake basins during the winter season and consequently decreasing winter imports. For comparison, 1 TWhe of electricity demand corresponds to about 11-12% filling level of the Swiss storage lake basins.

3.2.3 Impact of the IEA scenario in 2050

We evaluated the case when the electricity consumption in Switzerland increases by 50% compared to the reference year 2010, while the Swiss generation capacities installed evolved as developed by the BFE supply scenario in Figure 17 – BFE supply scenarios: the power plant capacities. Even when no CCGT plants were installed, our simulation results show that there would be enough conventional generation capacities in Europe to supply the import needs of Switzerland (20 TWh/y) in 2050[3]. The Swiss power line interconnections were on a yearly average, 65% of the time fully loaded at the current net transfer capacity (NTC), thereby showing that even today's transfer capacities would be sufficient to exchange all electricity imports and exports between Switzerland and its neighbors in the future.

[3] Please keep in mind we assumed that only PV and Wind capacities will be installed in Europe after 2020

However, 0.02% of the yearly load demand could not be satisfied in the IEA scenario due to lack of additional (country-internal) power plant capacities to generate sufficient electric power or grid transfer capacities to import lacking power (see Fig. 18).

Please note that the NTC constraints we have set in the Power Nodes dispatch simulations are chosen artificially restrictive (i.e. assuming the generally lower summer NTC values for all European cross-border capacities throughout the whole year). In real-life operation, the Swiss transmission system operator could request additional transmission capacity at specific times to avoid load curtailment. Table 7 summarizes the dispatch results for each decade of the IEA scenario, where the consumption increased by 50% (roughly 8% electricity demand increase for every decade).

Table 7 – IEA High Consumption Scenario

Parameter Analyzed	2010	2020		2030		2035		2050	
	-	Var C&E	Var E	Var C&E	Var E	Var C&E	Var E	Var C&E	Var E
Energy demand (TWh)	58.52	66.71	66.71	70.46	70.46	76.07	76.07	86.72	86.72
PV available (TWh)	0.32	0.52	0.52	1.91	1.91	3.18	3.18	11.12	11.12
PV int (%)	100%	100%	100%	1.00	100%	1.00	100%	0.97	98%
Wind available (TWh)	0.07	0.66	0.66	1.46	1.46	1.61	1.61	4.26	4.26
Wind int (%)	100%	99%	99%	1.00	100%	1.00	100%	0.98	99%
Variable Hydro (TWh)	29.66	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50
Var-Hydro int (%)	100%	99%	99%	1.00	100%	1.00	100%	0.98	99%
RES available (TWh)	30.05	31.68	31.68	33.87	33.87	35.28	35.28	45.88	45.88
RES integration (%)	**100%**	**99%**	**99%**	**100%**	**100%**	**100%**	**100%**	**98%**	**99%**
Demand covered by var-RES (%)	**51%**	**47%**	**47%**	**48%**	**48%**	**46%**	**46%**	**52%**	**52%**
Biomass (TWh)	1.66	1.92	1.90	4.59	4.58	5.04	5.02	4.80	4.77
Geothermal (TWh)	0.00	2.19	2.19	4.36	4.37	4.36	4.37	4.28	4.26
Dispatchable Hydro reservoirs (TWh)	8.22	7.24	6.74	5.92	5.79	6.02	6.41	8.25	7.81
Demand covered by dis-RES (%)	**17%**	**17%**	**16%**	**21%**	**21%**	**20%**	**21%**	**20%**	**19%**
GuD generation (TWh)	0.00	0.00	0.00	4.04	0.00	10.87	0.00	14.37	0.00
GuD capacity factor (%)				**42%**		**45%**		**60%**	
CHP generation (TWh)	0.95	5.91	5.61	6.55	6.12	6.95	6.52	6.68	6.65
Nuclear generation (TWh)	24.93	20.56	20.53	9.64	9.64	0	0	0	0
Demand covered by Conv.Supply (%)	**44%**	**40%**	**39%**	**29%**	**22%**	**23%**	**9%**	**24%**	**8%**
Winter Imports (TWh)	15.78	18.00	17.98	18.16	19.31	18.76	22.12	18.14	22.71
Winter Exports (TWh)	14.57	12.85	12.00	10.94	8.61	9.53	5.37	10.45	5.33
Winter Net balance (TWh)	1.21	5.15	5.98	7.23	10.70	9.23	16.75	7.70	17.38
Winter Demand (TWh)	31.76	36.20	36.20	38.23	38.23	41.28	41.28	47.06	47.06

Winter Demand covered by imports(%)	**4%**	**14%**	**17%**	**19%**	**28%**	**22%**	**41%**	**16%**	**37%**
Summer Imports (TWh)	14.39	15.52	15.33	16.55	16.42	17.70	18.65	16.10	17.32
Summer Exports (TWh)	22.04	21.21	20.84	20.53	19.19	17.56	15.20	18.16	14.80
Summer Net balance (TWh)	-7.64	-5.68	-5.51	-3.98	-2.77	0.15	3.45	-2.05	2.52
Summer Demand (TWh)	26.76	30.51	30.51	32.22	32.22	34.79	34.79	39.66	39.66
Summer Demand covered by imports (%)	**-29%**	**-19%**	**-18%**	**-12%**	**-9%**	**0%**	**10%**	**-5%**	**6%**
Total Imports (TWh)	30.17	33.52	33.31	34.71	35.72	36.46	40.77	34.25	40.03
Total Exports (TWh)	36.60	34.06	32.84	31.47	27.79	27.09	20.57	28.60	20.13
Total Net balance (TWh)	-6.43	-0.53	0.47	3.24	7.93	9.38	20.20	5.64	19.90
Total Demand covered by imports (%)	**-11%**	**-1%**	**1%**	**5%**	**11%**	**12%**	**27%**	**7%**	**23%**
PSP Number of Full Cycles per year	**94**	**231**	**242**	**198**	**208**	**208**	**198**	**230**	**224**
CO_2 emissions (million metric tons)	**0.59**	**3.66**	**3.48**	**5.56**	**3.79**	**8.33**	**4.04**	**9.46**	**4.12**
Yearly full load usage of NTC for cross border lines	45%	55%	51%	56%	52%	57%	57%	63%	65%

In the IEA high consumption scenario, Switzerland would:

- Import up to 17 TWh of its electricity demand in the winter months in the reference year 2050, if no gas-fired power plants (CCGT/GuD) are installed.
- If five CCGT plants (3.3 GW) were installed, the winter import need would decrease to about 7 TWh. In this case, the CCGT plants would run with a yearly capacity factor of 60%. As a comparison, today's Swiss winter imports are about 5 TWh (year 2011).
- Renewable energy sources, as envisioned by BFE supply scenario (Var E), would cover up to 70% of the yearly electricity demand, namely 52% by variable RES (var-RES) and 19% by dispatchable RES (dis-RES).

System Operator's Perspective

We present below the optimal dispatch results of the Swiss power system for the IEA high consumption scenario in 2050, in case no CCGT plants are installed. Such a scenario is, from a system operator's perspective, the most challenging scenario for balancing electricity supply and demand (Fig. 18).

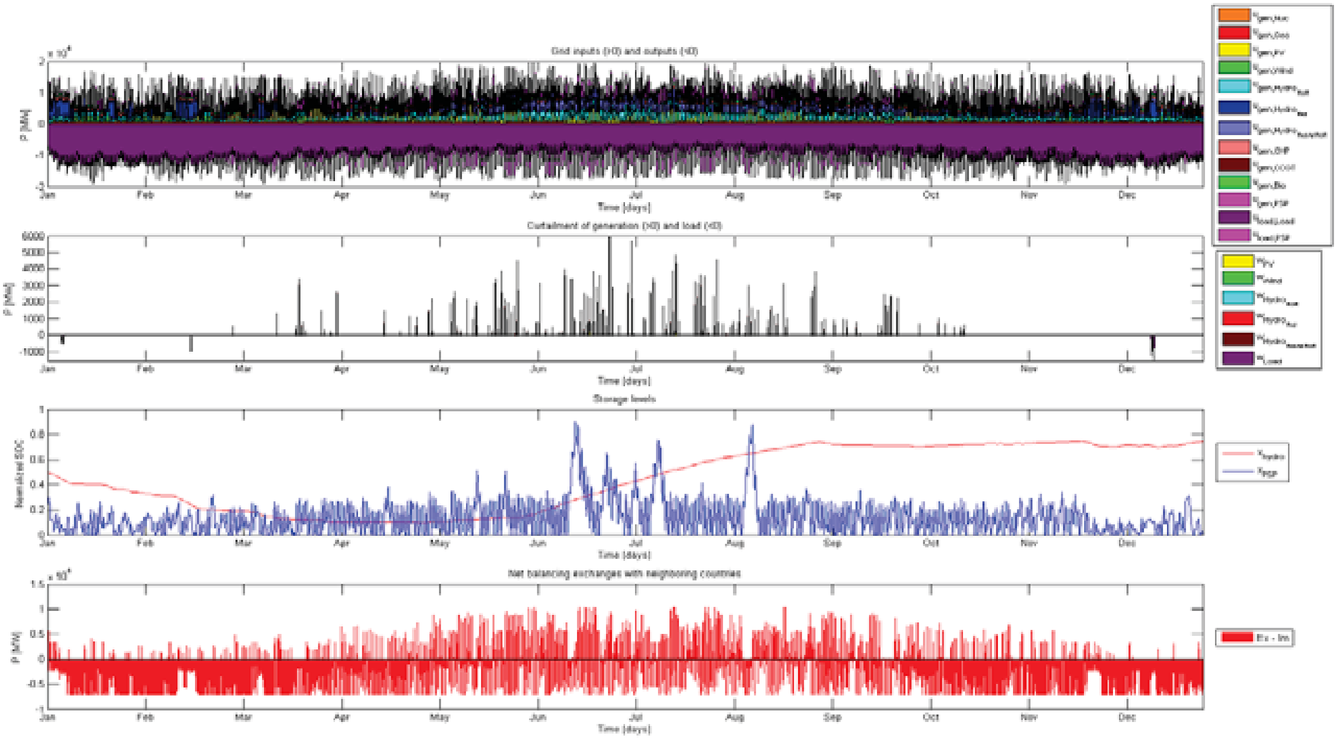


Figure 18 – Economic Dispatch of the Swiss Power System in 2050. (IEA consumption scenario, BFE renewable supply scenario – Var E)

First to notice in comparison to the power system dispatch of the reference year 2010 (Figure 12) is the occurrence of curtailment of RES generation, especially in the summer period as solar energy is more abundant and run-of-river hydro production more important.
The simulated power dispatch resulted in the curtailment of 1.5% of the total available PV energy (0.17 TWh/y), 1.3% of the total available Wind energy (0.055 TWh/y), 1% of the total available run-of-river energy (0.16 TWh/y) and 1.2% of the available Hydro reservoirs energy (0.27 TWh/y). In real operation mode, this means, PV plants are switched off from the grid via their DC/AC inverter units, wind turbine blades pitched and water being spilled from the run-of-river and hydro reservoir stations.

From an available renewable electricity supply of 53.7 TWh/y in 2050, a total of 98.5% of this RES production could effectively be integrated in the future Swiss Power System (assuming that all currently planned grid and pumped-storage unit capacity expansions are put in place). The RES generation share would thus be able to cover 60% of the projected electricity demand in 2050 in Switzerland. (IEA scenario: 87 TWh/y compared to today's 58 TWh/y net demand).

Secondly, we notice in this high consumption scenario with no nuclear and gas power plants inside Switzerland that the variation of the storage level of the Swiss hydro reservoirs (Fig. 18, subplot 3, red graph) is in line with historical deviations over the last 40 years as published by BFE [35]. Hydro reservoirs have produced on average 20.5 TWh/y [35] and the potential of hydro production expansion has been recently evaluated to be about 1.5 TWh/y [36]. In our dispatch simulations, we have constrained the hydro reservoirs production to a maximum of 22 TWh/y to respect Swiss environmental norms that limit the electricity production coming from this source.

Finally, in the last subplot (Fig. 18, subplot 4) we notice that the net balance of Switzerland is more frequently negative than positive as imports were necessary to balance the system. In total 20 TWh of net electricity imports were needed to satisfy the load demand in the reference year 2050. As a comparison, the net balance of Switzerland has varied the last four years between -4 TWh to +1 TWh (Swissgrid).

The following figures are a zoomed-in view of the yearly dispatch during two weeks in summer (high-infeed of renewables, Fig. 19) and two weeks in winter (low-infeed of renewables, Fig. 20). The first sub-plot of Figure 19 highlights the increase in activity of pump storage plants in the future compared to the 2010 power system dispatch in Figure 12. The PHS units activity shifted from pumping at nighttime and turbining at daytime, to, pumping at daytime and turbining at nighttime. This shift is needed as they are cycled daily to shave the peak of PV production during midday and shift it for peak consumption after working hours. In fact the usage frequency of PHs units increases from 94 full cycles for the reference year 2010 to 223 full cycles in 2050, thus proving their prominent role in the integration of renewable energy, especially solar energy. Nonetheless we observe in the second sub-plot of Figure 19 curtailments of available renewable supply. Over the whole year, they amount to less than 1% of the available RES production, which would be surely an acceptable range.

We can conclude that if Switzerland is to stick with the BFE Energy Strategy 2050 Renewables targets, the pump hydro storage capacity planned for the time-frame 2020-25, i.e. an addition of 3-4 GW to the existing capacity, is sufficient to fully integrate the production from the currently discussed PV and wind turbine capacity targets for Switzerland, given that there are no bottlenecks in the distribution grid that impede notably PV grid-integration and electricity transport to the pump hydro units in the mountains.

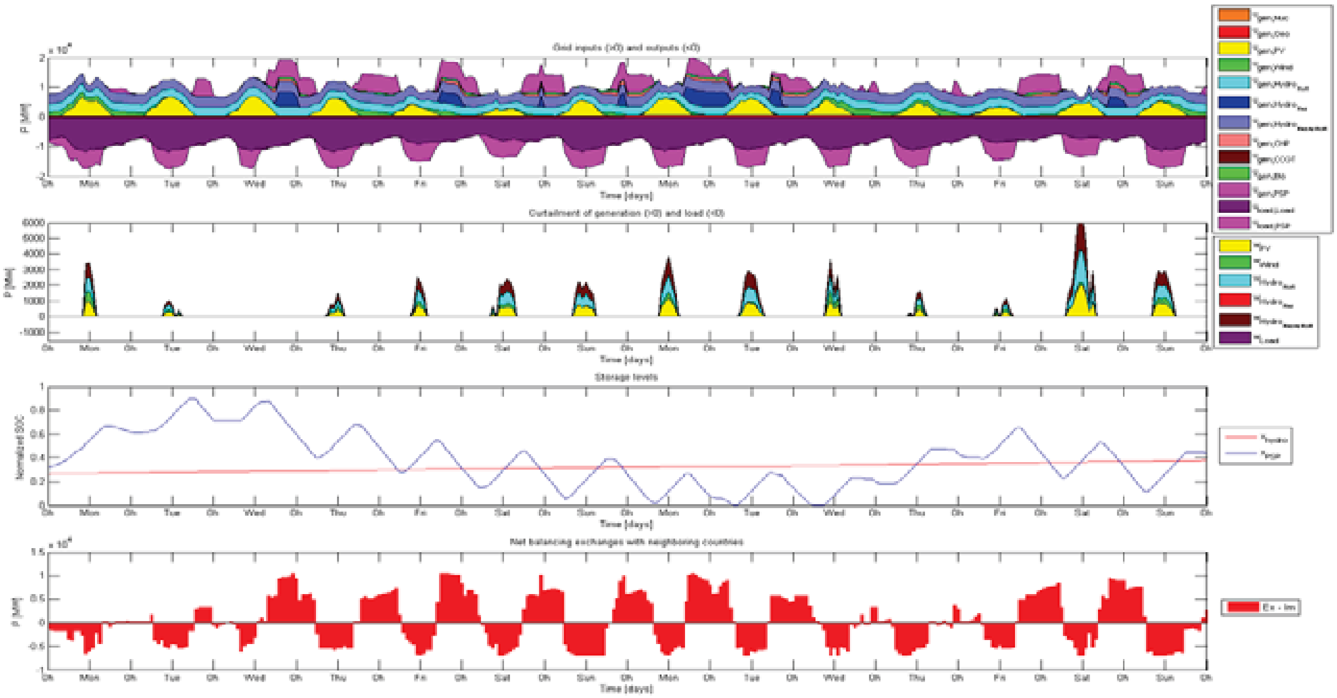


Figure 19 – Economic Dispatch of the Swiss Power System – Two Weeks in June 2050 (IEA consumption scenario, BFE renewable supply scenario [Var E]).

Figure 20 illustrates the power system dispatch in Switzerland during two winter weeks in 2050 with low wind and sun availability and low contribution from run of river. As shown in the last sub-plot, Switzerland was a net electricity importer almost all the time. Hydro reservoirs (dark blue) were dispatched to cover the lack of other energy production. As explained before 0.02% of the total yearly load demand was not satisfied in this high-consumption scenario (as shown in subplot 2): On a Friday afternoon and a Saturday noon in December, 1.1-1.2 GW out of 11-12 GW of peak load demand had to be shedded.

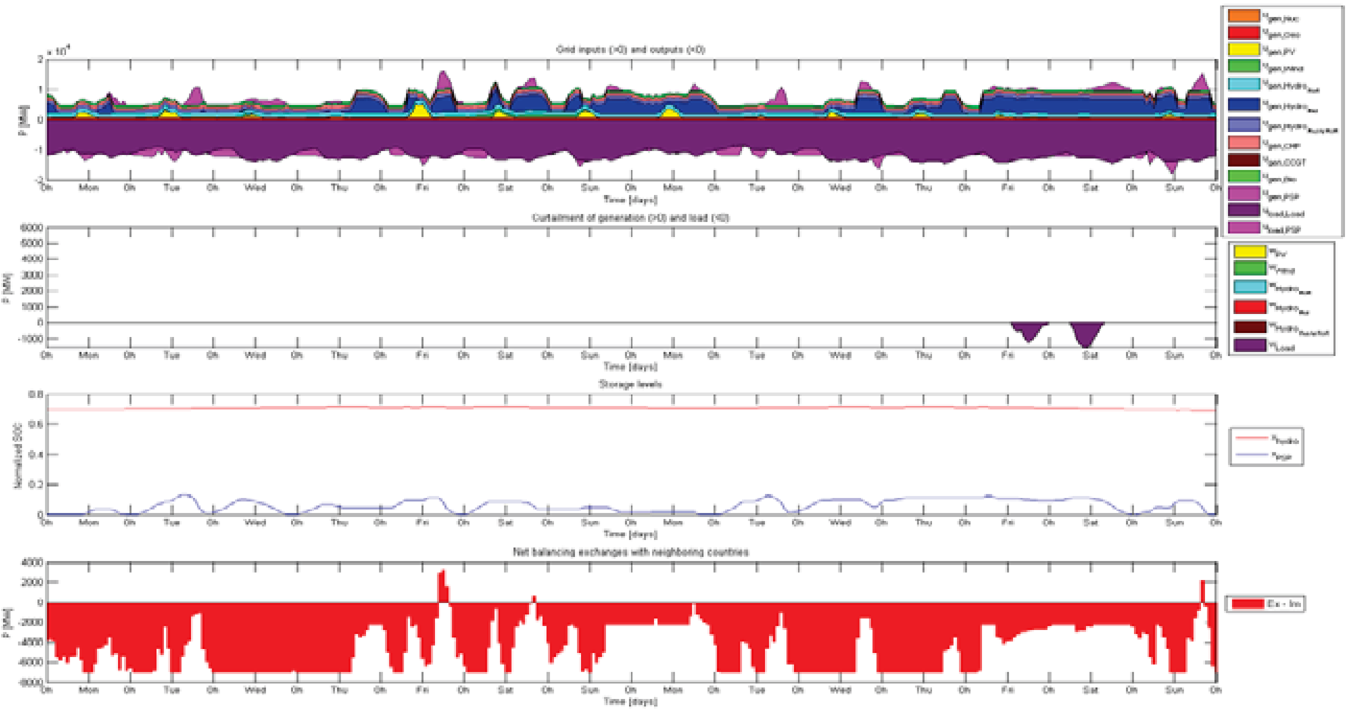


Figure 20 – Economic Dispatch of the Swiss Power System – Two Weeks in December 2050 (IEA consumption scenario, BFE renewable supply scenario [Var E]).

Please note that this controlled load shedding (i.e. brown-outs) would not have been necessary if the NTC capacities would have been slightly increased during the few critical hours, which would have been possible when taking into account so-called dynamic line rating calculations (i.e. the line cooling at low ambient temperatures).

Role of Energy Efficiency and Gas-Fired CCGT Power Plants

Energy efficiency measures quite naturally tend to decrease electricity imports. If Switzerland were able to keep its electricity demand constant, while installing significant RES capacities, i.e. the proposed 9 GW of PV, 2 GW of wind turbines, 0.5 GW of geothermal power plants, 0.6 GW of biomass power plants, a total of 12 GW of additional hydro power (8 GW hydro reservoir and 4 GW run-of-river plants), about 3-4 GW of additional pump storage plants, and with the existing 12 GW of Hydro power, Switzerland would be able to cover 88% of its electricity demand from Renewable Energy Sources. In turn Switzerland's seasonal net electricity balance would not differ much from today, i.e. some imports in the winter, some exports in the summer. Energy efficiency can thus play an important role in limiting the Swiss energy/electricity import dependency.

In a high electricity consumption scenario, e.g. the IEA scenario with a 50% load demand increase by 2050 compared to today, the large CCGT (GuD) power plants as well as the decentralized CHP power plants would significantly help to reduce the dependence on imports in the reference year 2050. In total about 21 TWh_e/y (Table 7) could be provided, which is about

- 16% of Switzerland's yearly electricity consumption could be provided, which means
- 70% less electricity imports from neighboring countries.

However, the natural gas imports to Switzerland in 2050 would have to increase by about 75% compared to the imports in the year 2011 (3 bm^3, IEA) to supply those CCGT and CHP power plants in order to produce the required electricity inside the country.

The CO_2 footprint from the Swiss electric power sector would in this case reach up to 10 million metric tons compared to only 0.34 million metric tons in 2009 [37].

Relevance of Internal Grid Expansion in Switzerland

Table 1 illustrated the aggregated line capacities connecting each of the five regions in Switzerland (CH1–CH5), according to data from a transmission grid model provided by swissgrid. The planned transmission grid expansion for the year 2020 would add 30% (or 6 GVA) to the existing total transmission capacity (20 GVA) between the Swiss regions.

We have compared the aggregated line limits between the five regions with power dispatch results from full-year simulations (IEA demand scenario, Var E supply scenario, 2050). Doing so, we are able to state how large the margin is between the maximum line usage throughout the year and the actual line limits. Table 8 illustrates the simulation results for the year 2010 (max. total line usage 51.3% – max. single line usage 89.3%) and 2050 (max. total line usage 35.7% – max. single line usage 70.1%).

Thereby, with respect to our simulations (max. single line usage), the expansion and reinforcement of the Swiss transmission grid, as planned by swissgrid, would increase the static security margin from about 10% today (year 2010) to about 30% (year 2050).

Table 8 – Comparison of Aggregated Line Limits to Actual Power Dispatch Results within Switzerland

Zone Connections	**Line Limits** (2010 Swiss Transmission Grid) (MVA)	**Maximum Line Usage** Power Dispatch (Year 2010) (MW)	**Maximum Line Usage** Power Dispatch (Year 2010) (in % of line limit)
CH1 ↔ CH2	4144	3336	80.5%
CH1 ↔ CH3	381	56	14.7%
CH1 ↔ CH5	4546	2599	57.2%
CH2 ↔ CH3	1869	488	26.1%
CH2 ↔ CH5	453	252	55.6%
CH3 ↔ CH4	934	193	20.7%
CH3 ↔ CH5	2494	2227	89.3%
CH4 ↔ CH5	5534	1292	23.3%
Total	**20355**	**10443**	**51.3%**

Zone Connections	**Line Limits** (2020 Swiss Transmission Grid) (MVA)	**Maximum Line Usage** Power Dispatch (Year 2050) (MW)	**Maximum Line Usage** Power Dispatch (Year 2050) (in % of line limit)
CH1 ↔ CH2	5260	3688	70.1%
CH1 ↔ CH3	381	34	8.9%
CH1 ↔ CH5	4546	1862	41.0%
CH2 ↔ CH3	3843	882	23.0%
CH2 ↔ CH5	1120	751	67.1%
CH3 ↔ CH4	934	90	9.6%
CH3 ↔ CH5	3160	844	26.7%
CH4 ↔ CH5	7510	1791	23.8%
Total	**26754**	**9546**	**35.7%**

Relevance of Pump Storage Plant Capacity Expansion in Switzerland

In Tables 9-10 the grid's integration capability of Renewable Energy Sources in Switzerland and its neighboring countries is presented, for the cases that the Swiss transmission grid and pumped hydro storage capacities are those of today (i.e. year 2010 grid and storage capacities) and those planned for the time-frame 2020-25 (i.e. about 6 GW pumped hydro storage capacity and the swissgrid 2020 transmission grid). Please keep in mind that it is assumed that neither the conventional power plant capacities nor the transmission capacities of Switzerland with its neighbors do improve after the reference year 2020. Only PV and wind turbine capacities increase from 2020 to 2050, finally representing 10% to 50% of the overall generation capacity shares in Europe. The availability of renewable supply in each country is defined by the renewable energy supply scenario of the IRENE-40 supply scenarios.

Table 9 – Variable Renewable Energy Integration in Switzerland and Surrounding Neighbors (For Existing Year 2010 Swiss Pump Hydro Storage and Transmission Grid Capacities)

	Energy demand (TWh)	Var-RES availability (in % of total prod.)	Var-RES curtailment (in % of available)	Wind availability (in % of Var-RES)	Wind curtailment (in % of available)	PV availability (in % of Var-RES)	PV curtailment (in % of available)	Hydro availability (in % of Var-RES)	Hydro curtailments (%)(in % of available)
CH	87	62	7	5	6	13	12	44	5
AT	98	68	1	11	1	16	1	42	1
DE	727	71	10	46	11	22	7	3	14
FR	815	46	7	23	6	16	5	7	10
IT	511	57	15	11	12	37	16	10	17

Table 10 – Variable Renewable Energy Integration in Switzerland and Surrounding Neighbors (For Planned Year 2020 Swiss Pump Hydro Storage and Transmission Grid Capacities).

	Energy demand (TWh)	Var-RES availability (in % of total prod.)	Var-RES curtailment (in % of available)	Wind availability (in % of Var-RES)	Wind curtailment (in % of available)	PV availability (in % of Var-RES)	PV curtailment (in % of available)	Hydro availability (in % of Var-RES)	Hydro curtailments (%)(in % of available)
CH	87	62	1	5	1	13	2	44	1
AT	98	68	1	11	1	16	1	42	1
DE	727	71	10	46	11	22	7	3	14
FR	815	46	7	23	6	16	5	7	10
IT	511	57	15	11	12	37	16	10	17

The results of Tables 9-10 highlight the importance of expanding the pumped hydro storage capacities within Switzerland:

- From being able to only integrate 93% of the available renewable electricity supply of 53 TWh (11 TWh PV, 4 TWh Wind, 38 TWh Hydro, reference year 2050) with the Swiss transmission grid and pumped storage capacities of the year 2010 (1.8 GW). Here, about 13% of available PV and 6% of available wind turbine production have to be curtailed.
- In contrast to this Switzerland would be able to integrate 99% of the available RES supply (of the reference year 2050), if the planned Swiss transmission grid and pumped storage capacities of the year 2020 (5.8 GW) would be available.
- Both Switzerland and Austria can integrate the highest RES shares thanks to their highly flexible power system and their pumped hydro storage plants and hydro reservoirs. There is a greater need for operational flexibility in Italy, Germany and France in order to significantly reduce RES curtailment there.

Dispatch Synthesis for All Scenarios in 2050

We summarize in Table 11 the power dispatch results we have obtained in our simulations for all relevant supply & demand scenarios for the year 2050 as well as for the reference year 2010. Important to note is:

- In all scenarios, hydro reservoirs have not been generating more than 22.2 TWh_e, which is the allowed hydro expansion as stated in the results of the BFE survey published in 2012 [25].
- In the efficiency scenario, even with no gas-fired power plants, Switzerland is able to keep a positive net balance, i.e. it is an electricity exporter over the whole year.
- In the IEA high consumption scenario and the BFE's renewable supply scenario (Var E), Europe is able to supply one-third of Switzerland's yearly electricity consumption (20 TWh_e) can be supplied in the form of electricity imports from the European power system.

Table 11 – Dispatch Synthesis for All Scenarios in 2050

	2010	IEA & Var E	IEA & Var C&E	WWB & Var C&E	POM & Var C&E	POM & Var E
Renewable Energies (TWh)						
Hydro reservoir	21.7	21.9	22.2	20.3	19.5	20.4
Hydro run of river	16.2	16.0	15.9	16.2	15.5	15.5
Biomass	1.7	4.8	4.8	5.2	4.5	4.6
Geothermal	0.0	4.3	4.3	4.4	4.3	4.3
PV	0.3	10.9	10.8	11.1	10.4	10.4
Wind	0.1	4.2	4.2	4.2	4.1	4.1
Total	39.9	62.1	62.1	61.4	58.3	59.3
Conventional Energies (TWh)						
Nuclear	24.9	0.0	0.0	0.0	0.0	0.0
CCGT	0.0	0.0	14.4	16.2	7.4	0.0
CHP	1.0	6.7	6.7	6.5	5.2	5.3
Total	25.9	6.7	21.0	22.7	12.6	5.3
Pump Hydro Plant (TWh)						
Turbine	5.0	11.8	12.2	13.0	15.1	14.9
Pump	5.8	13.8	14.2	15.2	17.7	17.5
Net Production (TWh)						
Total	65.0	66.8	81.1	81.9	68.3	62.1
Energy Exchange (TWh)						
Import	30.2	40.0	34.2	24.3	29.1	31.4
Export	36.6	20.1	28.6	37.4	36.8	33.0
Net balance (TWh)						
Load served	58.5	86.7	86.7	68.8	60.6	60.6
Load demand	58.5	86.7	86.7	68.8	60.6	60.6

3.3 Stress Tests of the Swiss Power System

Different stress test situations were simulated, in which a major blackout or other serious events happens in the interconnected European power system that prevent all cross-border electricity import&export between Switzerland and its neighbors. Moreover, we assume that such an event happens during the winter season, i.e. February, with a high load demand. To make matters worse, it is assumed that the storage lake reservoirs have already been emptied to a historically very low level (15%). Also, during the winter season only a low power in-feed from PV, wind and run-of-river plants can be expected.

The purpose of these stress test or "worst case" scenarios is to evaluate and show how long Switzerland can supply its own electricity demand using the energy content of the hydro reservoirs and the remaining minor other dispatchable production sources, i.e. biomass, waste incineration, geothermal, CHPs and, if available, gas-fired CCGT power plants.

We performed such a test on all BFE consumption and supply scenarios as well as the IEA high load demand scenario. Moreover, we simulated the IEA scenario for the case where there is no power in-feed at all from PV or wind units (i.e. a "worst-worst case" scenario).

The simulation results and their synthesis are given in Table 12.

3.3.1 BFE Scenarios

The Swiss power system can function normally in the BFE's efficiency (POM) and business-as-usual (WWB) scenarios for the simulated time period, in case the nuclear power plants are fully replaced by CCGT power plants (Var C&E) and the reservoirs are initially not fully depleted (storage lake level ≥ 15%).

In case no CCGT power plants are built as backup capacity (POM, Var E), the Swiss power system can be operated without any load reduction for about 15 days.

3.3.2 IEA Scenario

However, if Switzerland's electricity demand would increase by 50% compared to today (i.e. IEA high consumption scenario), five gas-fired CCGT power plants would not be sufficient to keep Switzerland fully independent from the remainder of the European power system. In this setup (IEA Var C&E), the Swiss power system could sustain itself for about two weeks' time.

With no CCGT power plants (IEA Var E – no wind and PV power production), the Swiss power system can sustain itself for a full week in the truly "worst-worst case" scenario (IEA high consumption without any wind&PV generation).

It was thus possible to show that in all tested scenarios, the Swiss power system can supply its nominal (i.e. full) electricity demand for at least one week – enough time for implementing possible counter measures (e.g. electricity rationing for large industrial loads etc.) that would allow to continue an autonomous system operation even beyond the calculated time periods.

Table 12 – Island Mode Operation of Swiss Power System (February 2050).

Reference Year	Consumption Scenario	BFE Supply Scenario	# of autonomous operation days – Initial storage lake filling level (15%)
2050	IEA (+50%)	Var E (GuD = 0)	9.5
		Var E (Wind&PV = 0)	7.5
		Var C&E (GuD = 5 units)	14.5
2050	POM (+3%)	Var E (GuD = 0)	15.5
		Var C&E (GuD = 5 units)	Full month
2050	WWB (+17%)	-	-
		Var C&E (GuD = 6 units)	Full month

3.4 The Impact of Higher PV Shares in Switzerland

3.4.1 Rooftop Area Availability in Switzerland

BFE/Prognos assumed in the original BFE Energy Strategy 2050 report that 9.2 GW of PV would generate an electricity production of about 11.2 TWh [9]. They have used hourly time-series for the solar radiation in Switzerland, according to 25 weather stations with a data set consisting of measurements from 2004 to 2011.

According to the manufacturer SolarWorld, a 1.6m^2 PV panel will deliver 180 W at normal operating condition[4]. Sticking to this reference, 1 kW of PV power capacity will occupy a rooftop space of 9m^2 and thus an installed capacity of 9.2 GW would need 80 km^2. According to a recent report published by the Swiss Federal Office of Statistics (BFS) [38, p. Fig. G4 and G10] the total infrastructure area in Switzerland is equal to 3080 km^2, out of which 49.4% and 7.8% represent residential and commercial building, from which 25% and 35% represent the actual rooftop area. Thereby the total available rooftop area in Switzerland is about 465 km^2 (of which 17% would be requirement for 9 GW PV panels).

We estimate thus that around 17% of the available Swiss rooftop area would need to be equipped with PV panels to reach a yearly PV production of 11.2 TWh$_e$, i.e. 19% of Switzerland's yearly electricity consumption (2010). On a sunny week-end day, a PV capacity of 9.2

[4] Normal Operating Condition and Temperature considers a drop in power output as PV panels get heated up during operation and sun irradiation is seldom at its theoretic maximum.
At standard operating condition (i.e. 1000W/m^2, 25°C) the same panel is rated at 240 W$_e$.

GW could cover 33% of the daily electricity demand. According to statistics of Switzerland's Feed-In Tariff (FIT) scheme for Renewables, Kostendeckende Einspeisevergütung (KEV), FIT-subsidized PV panels today only have an electricity production equivalent of about 900 full-load hours per year. This is in contrast to the BFE/Prognos PV production assumptions (i.e. 1200 full-load hours per year). Therefore, if one would stick to average PV electricity production yield of the KEV statistics, about 12 GW of installed PV power capacity would be needed to generate 11.2 TWhe and would occupy 23% of the available Swiss rooftop area.

Please note that all further calculations of rooftop availability are done using the original high BFE/Prognos PV yield assumption. (Their results can be multiplied by a factor of 1.3 to match the existing KEV PV yield statistics).

3.4.2 The Role of Pump Storage Plants for Integrating Higher PV Shares

As part of a parameter sensitivity analysis we have simulated the Power Node dispatch model with significantly higher PV shares, by doubling, tripling and quadrupling the PV capacity, assuming the same energy-to-power output ratio as employed in the BFE Energy Strategy 2050:

- 18.4 GW of PV capacity would occupy around 35% of the available Swiss rooftop area and generate 22 TWh_e,
- 27.6 GW of PV capacity would occupy around 50% of the available Swiss rooftop area and generate 33 TWh_e[5],
- 36.8 GW of PV capacity would occupy around 75% of the available Swiss rooftop area and generate 44 TWh_e.

With more fluctuating electricity production in the power system and limited operational flexibility resources, RES curtailments were necessary to balance electricity supply&demand.

We therefore ran a sensitivity analysis to study the effect of expanding the power&energy ratings of the pump storage units in Switzerland and understand their role for the integration of high PV shares. The starting point is a pumped hydro storage power rating capacity of 5.7 GW (year 2020 capacity) and today's energy storage capacity of about 50 GWh [11].

[5] The German Fraunhofer Institute states that 35.6 GW of PV systems have generated about 29.7 TWh_e in Germany during the full-year 2013. (Please note that about 3-4 GW PV were only installed sometime in 2013.)

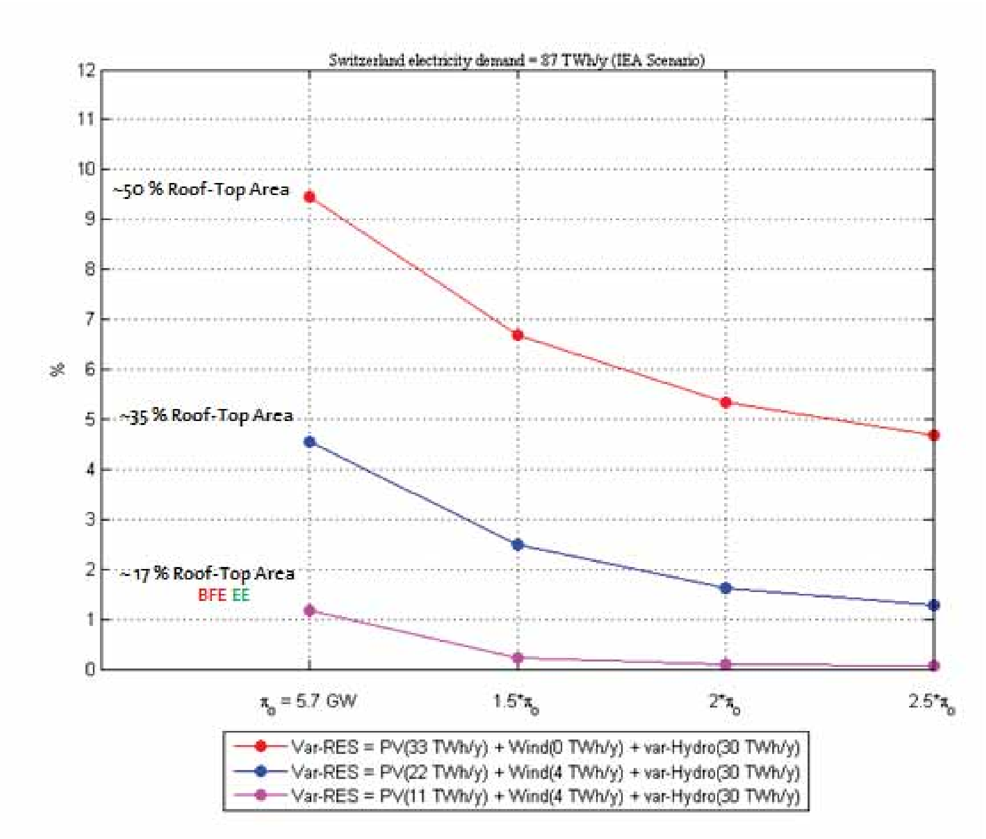


Figure 21 – Variable renewable energy supply curtailment as a function of pump storage power rating expansion

The first important conclusion we can draw from Fig. 21 is that the planned 5.7 GW storage power capacity and today's energy storage capacity of about 50 GWh would be sufficient to integrate all projected PV, Wind and variable hydro production shares in the year 2050. Only about 1% of the available RES supply could not be absorbed by the Swiss power system. The daily operation of the power system and the pump storage plants for this scenario was illustrated in Figure 18–Figure 20.

If Switzerland would decide to double the existing PV target, while not increasing the power rating capacity of pumped hydro units, then 5% of the available RES electricity supply could not be grid-integrated. The blue lines indicate that an increase by 250% of the pumping capacity would help decrease the curtailment to a level of less than 2%. Similarly, we see that for higher PV shares, increasing the rate at which excess energy can be stored does reduce curtailment but reaches a ceiling (or saturation) at some point, as the quantity of the storage reservoirs is not large enough. Figure 22 illustrates the effect of the PSP energy storage capacity on the renewable energy integration

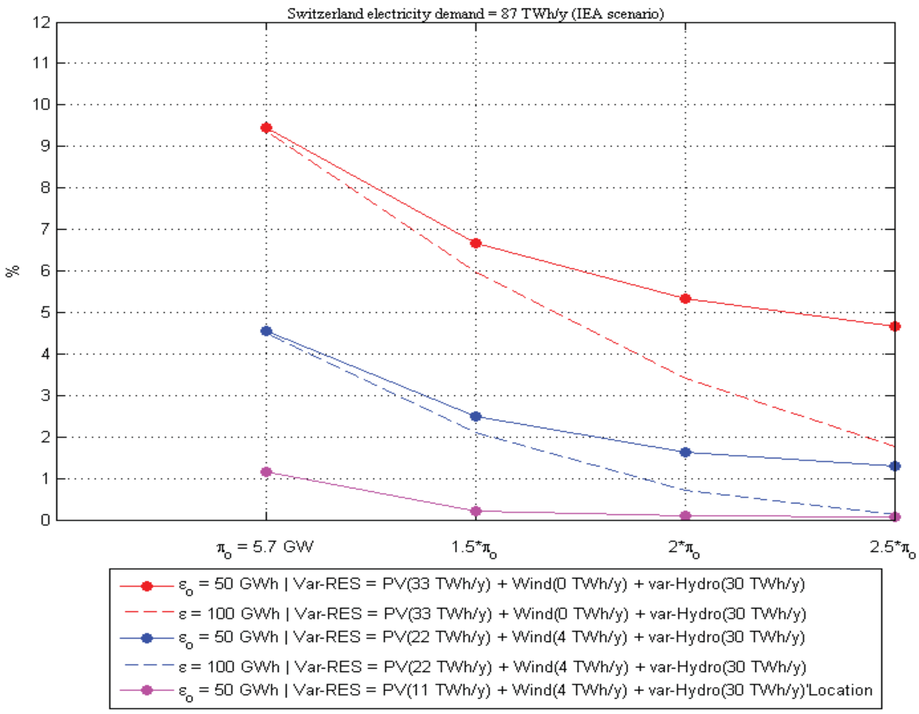


Figure 22 – Variable renewable energy supply curtailment as function of pump storage power and energy rating expansion

Our simulation results illustrated in Fig. 22 illustrate three points:

1. The pump storage units' power rating (GW) is a more significant parameter than their energy rating (GWh).
2. For all considered PV shares, increasing the pump storage units' energy capacity beyond its current capacity (about 50 GWh today) would have almost no influence on the RES grid integration unless the power rating is also increased significantly.
3. Increasing the pump storage units' energy capacity in absorbing daily PV power peaks would only become relevant, if both the existing PV target for Switzerland (9 GW, 11.2 TWh) as well as the available pump storage power capacity (5.7 GW) would be significantly higher.

3.4.3 The Influence of Electricity Imports

Higher PV energy targets would lead to a reduction in electricity imports, especially if the operational flexibility of the power system is increased in order to improve RES grid integration. Figure 23 illustrates the reduction in net imports over the course of the year and

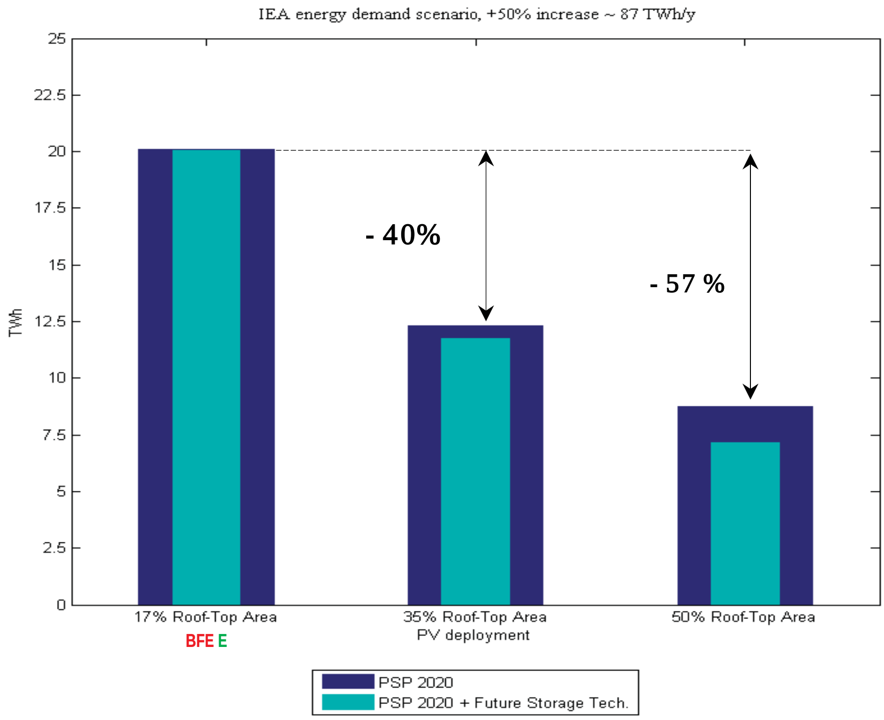


Figure 23 – Net import reduction in 2050 in Switzerland as a function of PV deployment

Fig. 24 details the seasonal change in importing and exporting power with a higher PV deployment in Switzerland

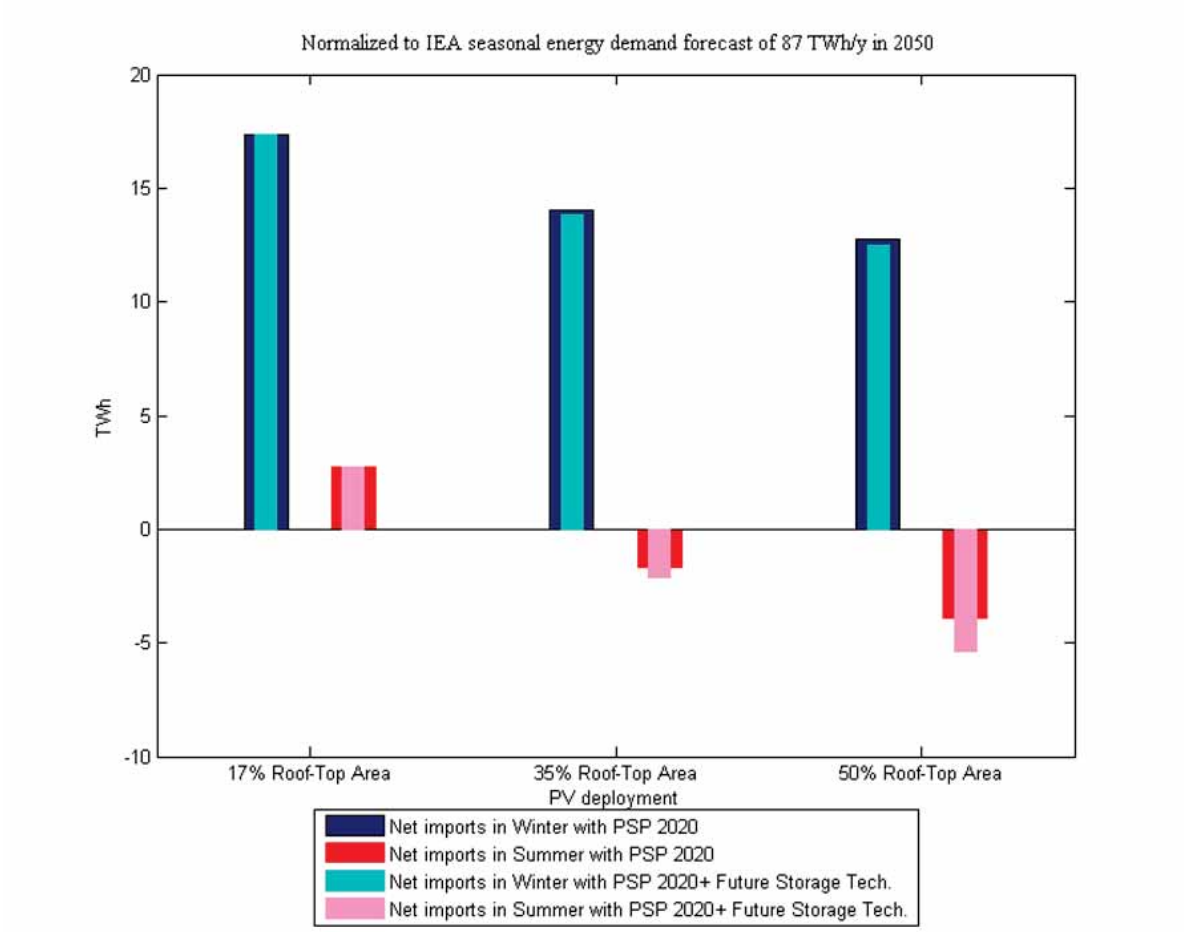


Figure 24 – Seasonal net import reduction in Switzerland as a function of PV deployment

Figures 23-24 both highlight the benefits of a higher PV deployment in Switzerland with respect to a reduction of electricity imports. Please note that the term "Future Storage Technology" stands for a further expansion of the planned pumped-hydro storage power capacity for the year 2020 (5.7 GW) by a factor of 2.5 and the corresponding storage energy capacity (50 GWh_e) by a factor of 2. Due to environmental and geographical constraints, such an expansion of hydro-based storage capacity in Switzerland could seem unrealistic. However, other storage technologies, for example decentralized battery units or chemical storage units, could alternatively be used for improving the grid integration of fluctuating RES supply inside Switzerland and, in turn, reduce net electricity imports.

Thereby in a hypothetical simulation scenario, where

- The electricity consumption of Switzerland increases by 50% until 2050 (IEA demand scenario),
- No Gas-fired CCGT plants are built to replace the existing nuclear power plants,
- About 28 GW of PV capacity are installed (triple the BFE's PV target of 9 GW), and
- Energy storage capacities, both power and energy ratings, are increased by factors of 2.5 and 2, respectively, compared to the planned pumped storage capacities for the time-frame 2020-25,

Switzerland could reduce its 20 TWh_e of yearly import needs to only 7 TWh_e. Such an import reduction would almost be equivalent to building five gas-fired CCGT power plants with a total capacity of 2.8 GW (see Table 7). In this case, however, Switzerland would not have to depend on significantly higher natural gas imports.

Figure 24 illustrates the seasonal net balance of Switzerland. A positive value means that Switzerland is a net electricity importer, negative means that it is a net electricity exporter. Our results show that with a larger PV deployment, the 18 TWh_e electricity import needs during the winter season could be reduced to 14 TWh_e or even 13 TWh_e, if the deployed PV capacities would be doubled or tripled with respect to today's PV target (9 GW). During summer, Switzerland switches from being a net importer to a net exporter. The increase in operational flexibility impacts more positively the summer period then the winter period as there is more PV production in the summer months.

4 Conclusion

The transmission grid-level of the Swiss power system was modelled as a highly interconnected and important part of the overall European power system, rather than an isolated island grid.

This functional modeling approach reflects more realistically the current role in and the importance of the Swiss transmission grid for the European power system: The combined volume of yearly electricity imports and exports (each ca. 30 TWhe) is in sum matching Switzerland's yearly net load demand (about 60 TWhe), whereas the yearly volume of the pure electricity transit through Switzerland (ca. 25 TWhe), for example from Germany and France towards Italy, corresponds to about 40% of Switzerland's yearly net load demand.

Full-year simulations with an hourly time resolution (i.e. 8'760 simulation steps) are accomplished using a predictive dispatch optimization scheme that explicitly takes into account available load and wind&PV forecast data as well as a realistic structure of the merit-order curve for electricity, including penalties for curtailing excessive renewable energy production and heuristically determined water value terms for the seasonal production profiles from storage lake reservoirs.

Infrastructure scenarios of both the current status of the Swiss transmission grid and Swiss pumped hydro storage capacities as well as their planned status for the time-period 2020-25 (i.e. planned transmission grid expansion and reinforcements as planned by swissgrid and an expansion of pumped hydro storage capacities as foreseen by BFE) are explored.

The transmission grid-level of the Swiss power system is sub-divided into five regions and modelled in more detail, whereas all other parts of the European power system are modelled on a more aggregated country-level (i.e. one grid node per country). In all dispatch simulations, the power exchanged between Switzerland and its neighbors was constrained to the currently existing level of the so-called Net Transfer Capacity (NTC) values for the Swiss cross-border electricity transmission corridors (ENTSO-E, 2010). This approach is in line with similar studies (e.g. VSE – Wege in die neue Stromzukunft, 2012 [10]).

The presented in-depth validation of the simulated power dispatch results with various IEA and BFE electricity statistics discusses both the model's features as well as transparently pointing out the unavoidable gaps between obtained simulation results and actual statistical data of the highly complex European power system (ref. year 2010). We argue that the Power Nodes simulator platform provides plausible simulation results that allow accurate power system analysis on the transmission grid-level, notably regarding the European electricity import/export patterns and the role of hydro-based energy storage capacities for the effective grid integration of fluctuating Renewable Energy Sources (i.e. wind&PV). Within Switzerland, which was modelled with greater detail than the remainder of the European power system, the mismatch between dispatch simulations and actual energy statistics is only about 2%.

The analysis of the performed transmission grid-level dispatch simulations of the upgraded Swiss Power System (i.e. planned status for the time-period 2020-25) within the European Power System show that the subset of the BFE scenarios, which from the perspective of the transmission grid operation are more demanding, i.e. the business-as-usual demand scenario (WWB – *Weiter Wie Bisher*) in conjunction with the supply scenario Var C&E as well as the energy efficiency demand scenario (POM – *Politische Massnahmen*) in conjunction with the supply scenarios Var C&E and Var E, as well as the additional high demand scenario (IEA, +50% electricity demand compared to year 2010), would induce demanding but feasible load flow patterns within the Swiss transmission system as well as technically feasible electricity import/export patterns with its European neighbors, while allowing an almost complete grid integration of fluctuating renewable energy production:

- About 95% of the available fluctuating RES supply can be grid-integrated in the POM demand scenarios (Table 5, reference year 2050), whereas
- Up to 99% of the available fluctuating RES supply can be absorbed in both the WWB demand scenarios (Table 6, reference year 2050) as well as in the IEA demand scenarios (Table 7, reference year 2050).

POM Demand Scenario & Var E Supply Scenario

If no gas-fired CCGT power plants were built to replace the existing nuclear power plants, Switzerland would remain a net electricity exporter on a yearly basis. In this case, the winter imports could still be in the same range as today (about 4–5 TWh_e in the year 2011, swissgrid, BFE) but could also double to about 8 TWh_e in case the storage lakes are managed more conservatively (i.e. keeping more hydro energy in the basins as an energy reserve margin). However, the supply scenario's RES installation targets, i.e. 9 GW of PV, 2 GW of Wind, 0.5 GW of geothermal plants and 0.4 GW of biomass power plants; as well as the 0.6 GW in the form of CHP plants, would have to be respected.

POM Demand Scenario & Var C&E Supply Scenario

If gas-fired CCGT power plants were built in the POM scenario, Switzerland could become a net exporter all year long.

All Demand Scenarios & Var C&E Supply Scenarios

Building gas-fired CCGT power plants would, however, dramatically increase the total GHG emissions of the electric power sector:

- POM Demand Scenario: 6.4 Mt CO_2-eq. (POM Var C&E, 2035, Table 5) and 6.0 Mt CO_2-eq. (POM Var C&E, 2050, Table 5)
- WWB Demand Scenario: 9.9 Mt CO_2-eq. (WWB Var C&E, 2035, Table 6) and up to 10.0 Mt CO_2-eq. (WWB Var C&E, 2050, Table 6)
- IEA Demand Scenario: 8.3 Mt CO_2-eq. (IEA Var C&E, 2035, Table 7) and up to 9.5 Mt CO_2-eq. (IEA Var C&E, 2050, Table 7).

To put these findings into perspective:

- Switzerland's total GHG emissions were about 54 Mt CO_2-eq in 2010 (IEA).
- For these supply scenarios Switzerland's total natural gas imports would increase by up to 75% compared to today (3 billion m3 natural gas imports in 2011, IEA).

IEA Demand Scenario & Var E Supply Scenario

In the high electricity demand scenario (IEA), in which electricity consumption would increase by 50% (0.8%/year) and reach about 87 TWhe in 2050, it is technically feasible that power plants in neighboring countries supply the necessary electricity imports of about 20 TWhe to Switzerland in case neither gas-fired CCGT power plants are built nor more RES capacities are installed. Here, Switzerland would be covering 23% of its annual electricity demand (and 37% of winter season demand) via imports (Table 7). The cross-border utilization level would on average reach 65% of the nominal NTC values in 2050 compared to only 50% in 2010.

IEA Demand Scenario & Var C&E Supply Scenario

In case the gas-fired CCGT power plants were built for the IEA scenario, Switzerland's yearly net imports would drop to only 5.6 TWhe (7% of annual electricity demand). In turn only 16% of the winter season demand would have to be covered by imports (Table 7). In turn the cross-border utilization level of available NTC grid capacities would be reduced to 57% on average. Both cases prove that Switzerland's existing cross-border capacities are already sufficient to fulfill the respective import needs.

Pumped Hydro Storage Capacity Needs

As for the needed pumped hydro storage capacity needs of Switzerland, the dispatch simulation results indicate that the expansion of the storage units' power capacity rating (GW) is significantly more important than the expansion of its energy capacity rating (GWhe).

To integrate up to 100% of the proposed wind & PV production targets from the BFE Energy Strategy 2050, there is no stringent need to expand today's pumped hydro unit's energy capacity (~50GWhe, ETH [11]). However it would be crucial to proceed with the planned power capacity additions (3-4 GW of pumping capacity) in order to effectively absorb the daily PV power peak at noon. In case only the currently existing pumped storage power capacity (about 1.8 GW) can be used and no alternative energy storage capacities, for example in the form of distributed battery storage, were available, 12% of the available PV electricity production (i.e. 1.3 TWhe) and 6% of the available wind turbine electricity production (0.25 TWhe) would have to be curtailed over the course of the simulation year.

The Swiss storage lake reservoirs (Speicherseen) with its total energy capacity of about 8'780 GWhe and a power capacity of about 10GW are clearly the backbone of the security as well as flexibility of the Swiss power system. In case the Swiss power system would have to operate in a hypothetical stress test situation (i.e. no electricity imports&exports with neighboring countries possible), the Swiss storage lakes could – almost single-handedly – keep the Swiss power system running for at least one week without significant load shedding under very pessimistic assumptions (i.e. historically very low storage lake energy content of only 15%, high winter load demand, low or even zero production from wind & PV units). The focus of this study has been the assessment of the technical capabilities of the transmission grid-level of the Swiss power system (and indirectly the European power system) for coping with the enacted nuclear phase-out as well as the significant fluctuating electricity production shares from Renewable Energy Sources as proposed by the different scenario combinations of the BFE Energy Strategy 2050.

Particular attention was given to the role of electricity imports & exports and hydro-based energy storage units in Switzerland. One of the key results of the study is that the planned upgrade of both the Swiss transmission grid capacity (swissgrid "Strategisches Netz 2020") as well as the Swiss pumped hydro storage capacity (BFE) would significantly improve RES grid integration by 2050. However, RES grid integration efforts – notably of the highly distributed PV units – will have to start on the distribution grid level. Cost-effective reinforcement strategies for the distribution grid as well as the transmission grid will become a key aspect of the coming years. Many Swiss distribution grid operators are conducting more detailed case studies in this field, for instance within the framework of the Verein SmartGrid Schweiz (VSGS) [7]. A recent ETH study came to the conclusion that the PV hosting capacity of Swiss distribution grids could be more than 50% of their annual electricity consumption [8, p. 105].

Economic aspects of the BFE energy strategy were explicitly not considered in this study, since this topic has already been treated in great detail by studies of BFE/Prognos (i.e. investment requirements of the transmission and distribution grids [39]), ETH Zurich (i.e. macro-economic impacts [11]) on a national level as well as on a tri-lateral level (i.e. economics of pumped hydro storage units in Austria, Germany and Switzerland [12]).

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