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LONG TERM EVOLUTION OF THE SWISS ELECTRICITY SYSTEM UNDER A EUROPEAN ELECTRICITY MARKET

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ABSTRACT

The Swiss electricity system accounts for one quarter of the Swiss final energy demand, providing a clean source of energy with almost zero carbon emissions. The current electricity supply mix mainly consists of hydro (≈55%) and nuclear power (≈40%); however, due to recent changes in policies, such as the phasing out of nuclear power, as well as increasing commitment towards climate change mitigation targets, the transition towards a sustainable future electricity system for Switzerland is highly uncertain. The pathway to a low-carbon future electricity system depends on various drivers, such as growth in electricity demand, resource availability, technology development, global and regional climate change mitigation policies and international energy prices. As Switzerland is highly integrated in the European electricity market, developments in neighbouring countries will also have significant impacts on the evolution of the future Swiss electricity system. The aim of this PhD dissertation is to generate insights into possible transition pathways for the Swiss electricity system in the medium- to long-term future, under varying boundary conditions for Europe in general, and the neighbouring countries of Switzerland, in particular.

Long-term planning is required to achieve a sustainable future Swiss electricity system that is optimally integrated with the European network. In order to facilitate strategic planning, numerous transition scenarios can be analysed with appropriate energy system modelling tools to generate insights for policy and decision makers. In this thesis, three TIMES framework-based modelling approaches have been developed, and are used to explore transition scenarios for Switzerland and its neighbouring countries. Each of these models is tailored to understand specific uncertainties regarding long-term capacity expansion, the integration of intermittent renewables, and the impact of developments in wider EU markets on Switzerland.

The main model developed over the course of this PhD is the Cross border Swiss TIMES Electricity Model (CROSSTEM). CROSSTEM is a technology rich, bottom-up, cost optimization model, covering the electricity system of Switzerland and its four neighbouring countries, namely Austria, France, Germany and Italy. The model identifies the “least-cost” combination of technologies and fuel mixes that satisfy exogenous electricity demands under varying boundary conditions. Three core scenarios

were explored to understand the technical and economic impacts of decarbonizing the electricity system in light of nuclear phase-out policies in Switzerland and the surrounding countries. A set of scenario variants were also analysed to understand the sensitivity of different drivers such as electricity demand, fossil fuel prices, resource potentials, technology costs, and carbon capture and storage (CCS) potentials, among others.

The second model discussed in this dissertation is the European Swiss TIMES electricity model (EUSTEM). EUSTEM is an extension of CROSSTEM to include the wider European electricity markets. Comparative analysis between EUSTEM and CROSSTEM helped quantify the extent to which policies and resource potentials in wider EU electricity markets influence the Swiss electricity system. A third model called CROSSTEM-Hourly Generation (CROSSTEM-HG) was developed to understand the challenges in integrating high shares of intermittent renewable technologies, such as solar PV or wind, in the electricity system. CROSSTEM-HG is a "pseudo-dispatch" type model, and was used to test the ad-hoc dispatchability of future electricity systems generated by CROSSTEM.

The thesis also covers the role of CROSSTEM in the ELECTRA framework, a project for the Swiss Federal Office of Energy (SFOE), in collaboration with EPFL and Econability. The ELECTRA framework combined a top-down general equilibrium model (GENESwIS) with a bottom-up electricity model (CROSSTEM-CH, a Swiss region-only variant of CROSSTEM) to create a coupled framework. The coupled framework was used to analyse the effects of Swiss energy and climate policies on the energy sector, while simultaneously accounting for impacts from international policies and electricity trade.

The results from the various models and scenarios shed insights into different transition pathways for the Swiss electricity system and helped identify a set of robust technologies and policies to achieve a low-carbon future electricity system.

In the absence of stringent climate change mitigation targets, natural gas-based generation combined with imported electricity constitute the cost optimal supply mix to replace outgoing nuclear plants in Switzerland. The decision to replace nuclear power with natural gas power plants in Switzerland increases the electricity generation cost in

2050 by around 45% compared to 2010. CO_2 emissions from the power sector are expected to increase ten-fold by 2050 in the absence of nuclear plants. The transition pathway to a decarbonized Swiss and European electricity market emphasizes the need for increased electricity trade between the regions. Meeting CO_2 emission targets at the European level instead of at national levels results in better utilization of renewable and CCS storage potentials in different countries. The analysis identifies CCS technologies as an important low-carbon electricity source. The share of CCS technologies in the total supply mix ranges from 6 – 23%, depending on the electricity demand and CCS storage potential assumptions. The analysis also reveals that while annual self-sufficiency for Switzerland in electricity generation improves energy independence and is desirable from a political point of view, it makes little economic or technical sense, especially in a future market with a high integration of renewable energy sources.

The development and application of the different models also revealed strengths and weaknesses of various approaches in analysing transition scenarios. A comparison of results from the CROSSTEM model and a standalone Swiss electricity model (STEM-E or CROSSTEM-CH) revealed that single region models overestimate the penetration of renewable technologies such as solar PV, and underestimate the need for flexible backup generation technologies such as gas plants or storage systems. This also results in an underestimation of total electricity system costs. A similar trend is seen in the comparison of EUSTEM and CROSSTEM, where the inclusion of wider EU electricity markets leads to considerable reduction in renewable deployment, and increase in electricity storage requirements in Switzerland. Finally, the analysis with CROSSTEM-HG showed that CROSSTEM underestimates the necessary storage or flexible generation capacities required to manage an electricity system with a high share of intermittent renewable technologies.

Keywords: Switzerland electricity system; European electricity system; climate change mitigation; decarbonization of power sector; nuclear phase-out policy; intermittency of renewable technologies; electricity storage;

ZUSAMMENFASSUNG

Die Schweizer Stromproduktion ist für rund ein Viertel des Schweizer Endenergieverbrauchs verantwortlich. Es handelt sich dabei um eine saubere Energiequelle mit sehr geringen CO_2-Emissionen, denn der derzeitige Produktionsmix basiert hauptsächlich auf Wasserkraft (≈ 55%) und Kernenergie (≈ 40%). Aufgrund aktueller politischer Entscheide wie dem Ausstieg aus der Kernenergie und dem verstärkten Engagement zur Vermeidung des Klimawandels ist die weitere Entwicklung der Schweizer Stromproduktion mit grossen Unsicherheiten behaftet. Die möglichen Entwicklungspfade hin zu einem nachhaltigen, zukünftigen Elektrizitätssystem werden von zahlreichen Treibern wie der Zunahme der Stromnachfrage, der Verfügbarkeit von Ressourcen, dem technologischen Fortschritt, der globalen und regionalen Klimapolitik, den internationalen Energiepreisen, etc. beeinflusst. Weil die Schweiz im Strombereich stark mit Europa vernetzt ist, haben Entscheide in den Nachbarländern ebenfalls einen grossen Einfluss darauf, wie sich die Schweizer Stromlandschaft in Zukunft entwickelt. Das Ziel dieser Dissertation ist es deshalb, verschiedene mittel- und langfristige Entwicklungspfade der Schweizer Elektrizitätsversorgung unter sich ändernden Rahmenbedingungen in Europa und speziell in den Nachbarländern der Schweiz zu untersuchen.

Für die optimale Integration eines nachhaltigen, zukünftigen Schweizer Elektrizitätssystems in den europäischen Verbund ist eine langfristige Planung unerlässlich. Zur Unterstützung der strategischen Planung können unterschiedlichste Szenarien mittels geeigneter Energiesystemmodelle untersucht und damit die erforderlichen Informationen für Politik und Entscheidungsträger zur Verfügung gestellt werden. Für diese Arbeit wurden drei verschiedene Ansätze, die alle auf der Modellierung mit TIMES basieren, verwendet, um die unterschiedlichen Entwicklungspfade und ihre Auswirkungen auf die Schweiz und die umliegenden Länder zu untersuchen. Jedes dieser Modelle ist darauf ausgerichtet, Unsicherheiten, die sich im Zusammenhang mit dem langfristigen Zubau von Kraftwerkskapazitäten, der Integration stochastischen erneuerbaren Energien und der Entwicklung der EU-Märkte für die Schweiz ergeben, besser zu verstehen.

Das Hauptmodell, das für diese Dissertation entwickelt wurde, heisst CROSSTEM -

Cross border Swiss TIMES electricity model. CROSSTEM ist ein technologiereiches, bottom-up Modell, das auf Kostenoptimierung basiert und die Elektrizitätssysteme der Schweiz und ihrer vier Nachbarländer (Österreich, Frankreich, Deutschland und Italien) abbildet. Das Modell berechnet die Kombination von Technologien und Energieträgern, die die exogen gegebene Stromnachfrage unter unterschiedlichen Rahmenbedingungen am kostengünstigsten befriedigt. Die drei Hauptszenarien wurden im Hinblick auf die technischen und ökonomischen Auswirkungen der Dekarbonisierung der Stromproduktion auf die Schweiz und die umliegenden Ländern und unter Berücksichtigung des Schweizer Kernenergieausstiegs untersucht. Um die Abhängigkeit von verschiedenen Treibern wie Stromnachfrage, Preise fossiler Energieträger, Ressourcen, Kosten der Technologien, Potential für Carbon Capture and Storage (CCS), etc. besser zu verstehen, wurden zusätzliche Szenariovarianten analysiert.

Das zweite Modell, das in dieser Dissertation beschrieben wird, ist das European Swiss TIMES electricity model (EUSTEM). Das EUSTEM ist eine Erweiterung des CROSSTEM und berücksichtigt somit weitere europäische Strommärkte. Als Ergänzung zu CROSSTEM konzipiert unterstreicht das EUSTEM den Einfluss der Entwicklungen in den weiteren europäischen Strommärkten auf die Schweiz. Vergleichende Analysen der Resultate von EUSTEM und CROSSTEM erlauben es, den Einfluss unterschiedlicher Strategien und Ressourcen in den weiteren EU Strommärkten auf das Schweizer Elektrizitätssystem abzuschätzen. Das dritte Modell, CROSSTEM-Hourly Generation (CROSSTEM-HG), wurde mit dem Ziel entwickelt, die Herausforderungen, die sich im Zusammenhang mit der Integration stochastischer erneuerbarer Energien wie Photovoltaik und Windenergie stellen, zu verstehen. CROSSTEM-HG ist ein Pseudo-Dispatch-Modell, das für einen ad-hoc Test der Verfügbarkeit der vom CROSSTEM errechneten Produktionskapazitäten auf stündlichem Niveau erstellt wurde.

Die vorliegende Dissertation beschreibt zudem die Rolle des CROSSTEM im ELECTRA-Projekt, das in Zusammenarbeit mit der EPFL und Econability für das Bundesamt für Energie (BFE) durchgeführt wurde. Das ELECTRA-Projekt hatte zum Ziel, ein top-down Gleichgewichtsmodell (GENESwIS) mit einem bottom-up

Elektrizitätssystemmodell (CROSSTEM-CH; Variante des CROSSTEM, die nur die Schweiz abbildet) zu koppeln. Das gekoppelte Modell wurde für die Analyse der Auswirkungen der Schweizer Energie- und Klimapolitik auf den Energiesektor unter Einbezug der Einflüsse von internationaler Politik und Stromhandel verwendet.

Die Analyse der Resultate der verschiedenen Modelle und Szenarien erlaubten Einblicke in die verschiedenen möglichen Entwicklungspfade der Schweizer Stromversorgung und die Bestimmung der Kombinationen von Technologien und Strategien, die die Erreichung der gewählten Klimaziele ermöglichen.

Ohne ambitionierte Klimaziele stellen Gaskraftwerke gemeinsam mit Stromimporten den kostengünstigsten Ersatz der auslaufenden Stromproduktion aus Kernkraftwerken in der Schweiz dar. Der Ersatz der Kernkraftwerke mit Gaskraftwerken erhöht jedoch die Stromgestehungskosten in der Schweiz bis 2050 um rund 45% gegenüber dem Jahr 2010 und die CO2-Emissionen des Stromsektors um das Zehnfache. Beim Entwicklungspfad, der zu einer dekarbonisierten Stromversorgung führt, gewinnt hingegen der Stromhandel zwischen den Regionen stark an Bedeutung. Wenn die CO2-Ziele auf europäischem statt auf nationalem Niveau gesetzt werden, führt dies zu einer besseren Ausnutzung der CO2-Speicherkapazitäten und der Potentiale der neuen erneuerbaren Energien in den einzelnen Ländern. Kraftwerke mit CCS sind eine wichtige CO2-arme Stromquelle. Ihr Anteil an der gesamten Stromproduktion erreicht in Abhängigkeit der Stromnachfrage und der CO2-Speicherpotentiale zwischen 6% und 23%. Wenn sich in der Jahresbilanz Stromimporte und –exporte die Waage halten müssen, die Schweiz in der Nettobetrachtung also autark ist, wird die Abhängigkeit der Schweiz von Energieimporten reduziert, was aktuell politisch als wünschbar bezeichnet wird. Aus wirtschaftlicher und technischer Sicht hingegen macht die über das Jahr erreichte Autarkie wenig Sinn, speziell in zukünftigen Elektrizitätssystemen, die auf einem grossen Anteil neuer erneuerbarer Energien basieren.

Die Entwicklung und Anwendung der unterschiedlichen Modelle zeigte auch die Stärken und Schwächen der verschiedenen Ansätze zur Analyse von Szenarien auf. Beim Vergleich der Resultate aus dem CROSSTEM und der Variante des CROSSTEM, die nur die Schweiz abbildet (STEM-E oder CROSSTEM-CH) zeigt sich, dass Modelle von Einzelregionen den Einsatz von erneuerbaren Technologien wie Photovoltaik überschätzen und gleichzeitig den Bedarf an flexiblen Kapazitäten wie Gaskraftwerken oder Stromspeicherung unterschätzen. Dies führt zu einer Unterschätzung der Gesamtsystemkosten des Elektrizitätssystems. Ähnliches ist beim Vergleich von EUSTEM und CROSSTEM zu beobachten: die Berücksichtigung weiterer europäischer Strommärkte führt zu einer deutlichen Reduktion der Erzeugung aus neuen erneuerbaren Energien und erhöhtem Speicherbedarf in der Schweiz. Die Analyse mit dem CROSSTEM-HG zeigte ebenfalls auf, dass CROSSTEM den Bedarf an Stromspeichern oder flexiblen Erzeugungskapazitäten in einem Elektrizitätssystem mit einem hohen Anteil an stochastischer Produktion unterschätzt.

Keywords: Schweizer Elektrizitätssystem; europäisches Elektrizitätssystem; Vermeidung des Klimawandels; Dekarbonisierung der Stromversorgung; Ausstieg aus der Kernenergie; stochastische erneuerbare Stromerzeugung; Stromspeicherung

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List of Abbreviations and Acronyms

ADAM	Adaptation and Mitigation strategies
AF	Availability factor
AT	Austria
BENELUX	Belgium, Netherlands and Luxemburg
BFE	Bundesamt für Energie
BMLFUW	Bundesministerium für Land- und Forstwirtschaft, Umwelt und Wasserwirtschaft
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEPE	Centre for Energy Policy and Economics
CGE	Computable General Equilibrium
CH	Switzerland
CHF2010	Swiss Francs (2010)
$CHF_{2010}/t\text{-}CO_2$	Swiss France per tonne CO2
CHP	Combined Heat and Power
CITE	Computable Induced Technical Change and Energy
CO2	Carbon dioxide
CROSSTEM	Cross border Swiss TIMES electricity model
CROSSTEM-CH	CROSSTEM - Swiss version
CROSSTEM-HG	CROSSTEM-Hourly Generation model
CSP	Concentrated Solar Power
DE	Germany

DIME	A Dispatch and Investment Model for European Electricity Markets
DLR	Forschungszentrum der Bundesrepublik Deutschland für Luft- und Raumfahrt
EAST	Eastern Countries
EFOM	Energy Flow Optimisation Model
ELECTRA	Electricity markets and trade in Switzerland and its neighbouring countries
ENSI	Eidgenössische Nuklear-sicherheitsinspektorat (Swiss Federal Nuclear Safety Inspectorate)
ENTSO-E	European network of transmission system operators for electricity
EOH	End of horizon
EPEX	European Power Exchange
EPR	European Pressurised Reactor
ETEM	Energy Technology Environment Model
ETH	Eidgenössische Technische Hochschule
ETS	Emission Trading Scheme
ETSAP	Energy Technology Systems Analysis Program
EU	European Union
EUR	Euro - currency
Euro-MM	European Multi-regional MARKAL model
EUSTEM	European Swiss TIMES electricity model
EWI	Energiewirtschaftliches Institut
FAL	Fall / Autumn
FASC	Federal Authorities of the Swiss Confederation
FBR	Fast Breeder Reactor

FOM	Fixed operation and maintanence costs
FoNEW	Forschungsstelle für Nachhaltige Energie- und Wasserversorgung
FR	France
GAMS	General Algebraic Modeling System
Gas (B)	Gas - Baseload plant
Gas (F)	Gas - Flexible plant
GDP	Gross Domestic Product
GHG	Green house gas
GRE	Greece
GW	Gigawatt
Hydro (D)	Hydro (Dam)
Hydro (P)	Hydro (Pump)
Hydro (R)	Hydro (River)
IEA	International Energy Agency
IER	Institutes für Energiewirtschaft und Rationelle Energieanwendung
IOT	Input Output Table
IPCC	Intergovernmental Panel on Climate Change
IRES	Intermittent Renewables
IT	Italy
JRC	European Joint Research Center
LWR	Light Water Reactor
MARKAL	Market Allocation model
Mt CO_2	Megatonne of CO2
MW	Megawatt

NEP	Neue Energie
NORDIC	Nordic regions
NPP	Nuclear Power Plant
NTC	Net transfer capacity
O&M	Operation and Maintanence cost
OECD	Organisation for Economic Co-operation and Development
PJ	Petajoule
POM	Politische Massnahmen
PSI	Paul Scherrer Institute
Pump	Charging of pumped hydro storage.
PV	Photovoltaic
RES	Reference Energy System
ROR	Run-of-river
RTE	Réseau de Transport d'Électricité
SA	Saturday
SES	Swiss Energy Strategy
SFOE	Swiss Federal Office of Energy
SMM	Swiss MARKAL Model
SPAPO	Spain and Portugal
SPR	Spring
STEM	Swiss TIMES Energy model
STEM-E	Swiss TIMES electricity model
SU	Sunday
SUM	Summer

t CO2	tonne CO2
T&D	Transmission and distribution system
t/TJ	tonne per Terajoule
TERNA	Transmissione Elettrica Rete Nazionale in seno all'ENEL
TIMES	The Integrated MARKAL-EFOM System
TIMES-PEM	TIMES Pan European Model
TJ	Terajoule
TSO	Transmission System Operator
TWh	Terawatt-hours
UKIRE	United Kingdom and Ireland
UVEK	Das Eidgenössische Departement für Umwelt, Verkehr, Energie und Kommunikation
VEDA	Versatile Data Analyst
VOM	Variable operation and maintanence costs
VSE	Verband Schweizerischer Elektrizitätsunternehmen
WEO	World Energy Outlook
WIN	Winter
WK	Weekday
WWB	Weiter Wie Bisher

1 INTRODUCTION

The electricity sector in Switzerland is an important contributor to the Swiss energy system, accounting for one quarter of the Swiss final energy demand. It is an important source of revenue and provides a clean source of energy with almost zero carbon emissions (Bundesamt für Energie, 2014a). This is partly due to the reliance on nuclear power, which accounts for around 40% of the total Swiss electricity generation mix.

The future of the energy sector however is currently at a crossroads. As a consequence of the Fukushima nuclear accident in Japan, the Swiss federal government decided to gradually phase-out nuclear energy as part of its new energy strategy (FASC, 2011), thereby removing the option of an important low-carbon source of electricity. Switzerland also has ambitious greenhouse gas reduction targets, with the aim of achieving 70 – 85 % lower emissions by 2050 compared to 1990 levels. While this target is for the whole energy system, it has important repercussions on the electricity sector as well.

Europe is undergoing a similar transformation, both in terms of nuclear policies as well as climate mitigation targets. The European Union (EU) emphasises a low carbon energy pathway for the long term future and the EU Roadmap to 2050 foresees an almost complete decarbonisation of its electricity sector by 2050 (European Commission, 2011). The decision to phase out nuclear power in certain EU member states (e.g. Germany) could undermine the policy objectives on climate change mitigation. A number of alternative technologies are being discussed, which include renewable resources such as solar, wind, biomass, geothermal, as well as others such as Carbon Capture and Storage (CCS). Each of these technologies have certain trade-offs in terms of supply security, system balancing, economic impacts, environmental factors etc. Hence, it is important to explore non-nuclear alternative sources of electricity supply and understand their implications in a wider context, both for Europe and Switzerland.

1.1 Scope of the analysis

The overall aim of this dissertation is to generate insights into possible transition pathways for the Swiss electricity system in the medium- to long term future, under varying boundary conditions in Europe in general, and neighbouring countries of Switzerland in particular. The thesis analyses various cost-optimal pathways to achieve a decarbonised power sector for Europe and Switzerland by 2050, and the technical, environmental and economic implications of choosing various low-carbon technologies to achieve the climate mitigation goals. The results seek to assist Swiss policy makers to realise its goal of a stable, secure and sustainable electricity system which is optimally integrated with the European network.

1.2 Methodology

In order to better understand and quantify the transition to a future non-nuclear Swiss electricity system, a set of “what-if” scenarios have been developed and analysed using an electricity system model of Switzerland and its neighbouring countries. A new electricity model was developed over the course of PhD, called **Cros**s border **S**wiss **T**IMES **E**lectricity **m**odel (CROSSTEM). CROSSTEM is an extension on the Swiss TIMES electricity model (STEM-E) (Kannan & Turton, 2011) by including the four neighbouring countries of Switzerland namely Austria, France, Germany and Italy. CROSSTEM is a technology rich, perfect foresight, cost optimisation framework, which identifies the “least-cost” combination of technologies and fuel mixes based on their operation characteristics to satisfy exogenously given electricity demands under given technical, environmental and other external constraints. The model framework allows for prospective analysis over a long model horizon (2010 – 2070) while at the same time being able to represent a high level of intra-annual detail in demand and supply, which is particularly important for integrating highly intermittent renewable sources of electricity such as solar and wind power.

Results from the CROSSTEM model are further supported by insights from two supplementary models; the CROSSTEM-**H**ourly **G**eneration model (CROSSTEM-HG) which tests the ad-hoc dispatchability of the electricity system, and the **Eu**ropean **S**wiss **T**IMES **E**lectricity **M**odel (EUSTEM) which examines the influence of wider EU electricity market developments on the Swiss electricity supply.

Together, the three models investigate a range of uncertainties via scenario exploration, to identify a set of robust technologies and policies for the Swiss electricity system.

1.3 Structure of the thesis

The thesis is structured into seven chapters that describe the background and motivation for the models, analyse the results and discuss potential alternatives for the long term evolution of the Swiss electricity system. Chapter 2 provides the background and motivation for the current analysis. Chapter 3 describes the methodology of the CROSSTEM model, detailing the model structure and key assumptions used in the model.

The next two chapters analyse the evolution of the Swiss electricity system under various boundary conditions in the neighbouring countries using CROSSTEM. Chapter 4 provides an overview of the ELECTRA project, under which the CROSSTEM model was developed and coupled with a top-down general equilibrium model. This chapter also highlights the advantages of a multi-region Swiss model over single region Swiss models. This chapter is part of the ELECTRA project report that was submitted to the Swiss Federal Office of Energy (SFOE) for publication (Maire et al., 2015). Chapter 5 analyses the nuclear phase-out and decarbonisation of the electricity system of Switzerland and its neighbouring countries. For this analysis, some structural improvements and data updates are implemented in the model (compared to the model discussed in Chapter 4. Updates include improved representation of interconnectors between regions, the inclusion of additional storage technologies, as well as changes to key input assumptions such as technology costs, CCS potentials, electricity demands etc.

Chapter 6 and 7 discuss the supplementary models that were developed towards the end of the PhD. Chapter 6 focusses on the development and application of the EUSTEM model. The scenario results presented in this chapter highlight the impacts of developments in wider EU markets on Switzerland. By comparing results from EUSTEM and CROSSTEM, conclusions are drawn on why models with increased regional detail provide better results. Chapter 7 deals with addressing short-term intermittencies of renewable technologies such as solar PV and wind via the development of the CROSSTEM-HG model. The motivation, methodology and some illustrative results from this new model are described in this chapter, with an outlook on how this modelling approach can be improved and used in future.

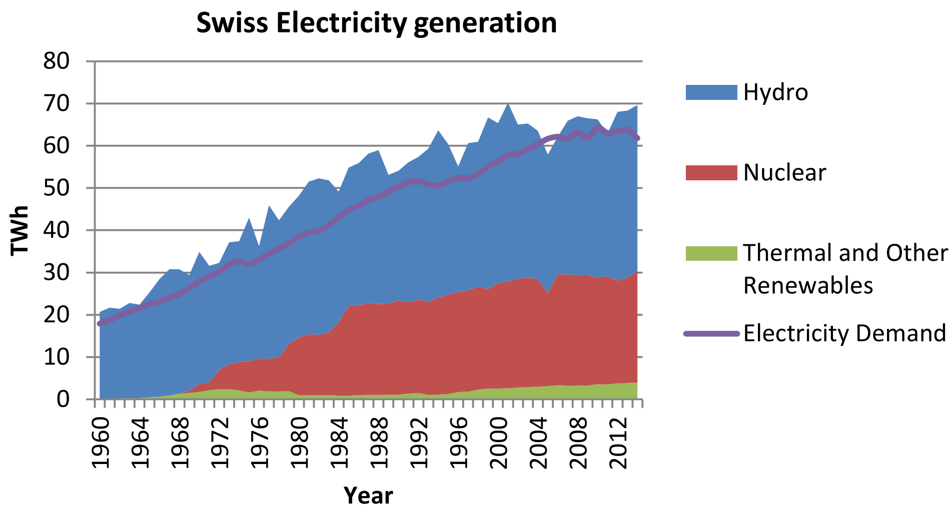
Finally, Chapter 8 presents an overview of the summary and conclusions drawn from the methodology and scenario analysis presented in the thesis. The dissertation concludes with an outlook on possible future work.

2 Transformation of the Swiss Electricity System

This chapter describes the historical developments of the Swiss electricity system, as well as potential challenges to be addressed in the near and long term future. The chapter begins with a brief description of the evolution of the Swiss electricity system, and its current status. It will highlight the importance of electricity trade in terms of supply – demand balancing, its significance as a revenue source as well as the role of Switzerland in interconnecting Europe. This will be followed by a discussion of the potential uncertainties that will shape the future of the electricity system. The chapter then moves onto a literature review of different energy-economic modelling approaches that attempt to deal with these uncertainties. The chapter concludes by explaining why a new modelling approach is necessary, and what research questions would be addressed with the new model.

2.1 Introduction

The electricity sector is an important contributor to the Swiss energy system and economy, providing one quarter of the Swiss final energy demand, while generating an annual turnover of about CHF 32 billion in 2013, about 5% of the Swiss national GDP of that year (Bundesamt für Energie, 2014a, 2014b). The evolution of the Swiss electricity system is shown in Figure 2-1. While hydro sources were sufficient to cover the whole electricity demand initially, the continuing increase in electricity demand led to investment in nuclear power, with the last nuclear plant (NPP Leibstadt) coming online in 1984. The historically high utilisation of hydro resources has resulted in limited expansion potentials for the future. In recent times, new renewable technologies such as solar photovoltaic (PV) and wind are increasing in importance, contributing to around 2% of the electricity supply in 2014.

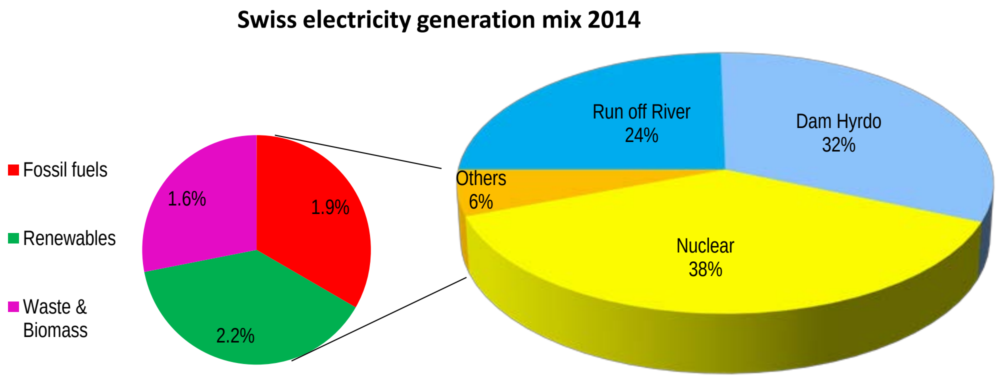


Source: (Bundesamt für Energie, 2014a)

Figure 2-1: Evolution of the Swiss electricity system

Figure 2-2 shows the electricity generation mix in Switzerland for the year 2014. About 56% of the electricity was generated from hydro, 32% from nuclear, with 6% coming from fossil fuel, waste and new renewables (Bundesamt für Energie, 2014a).

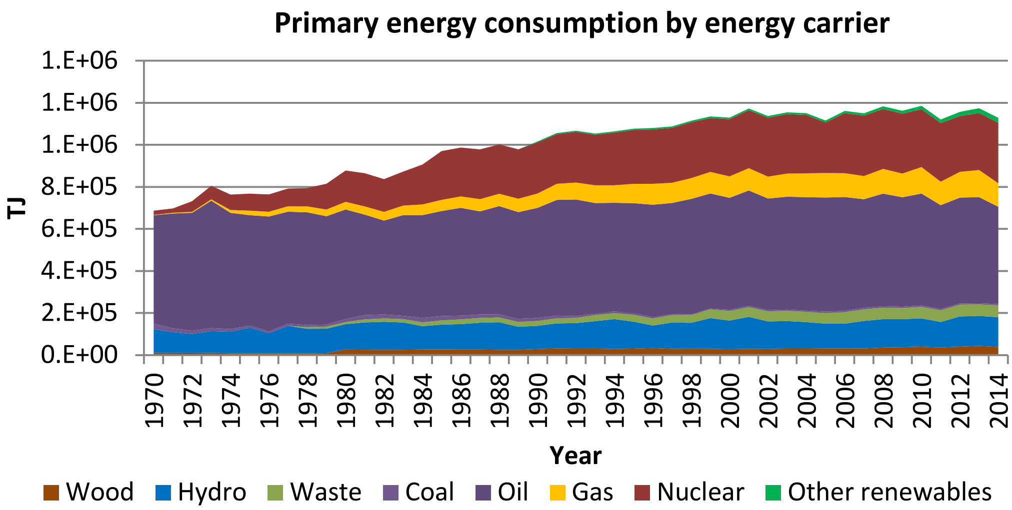
Nuclear has played a very important role in the primary energy mix since the 1960’s, when it was realised that electricity demands could not be met by hydro sources alone. Since then, there has been a constant increase in the share of nuclear power in the energy consumption.



Source: (Bundesamt für Energie, 2014a)

Figure 2-2: Swiss electricity generation mix (2014)

However, after the Fukushima Daiichi nuclear accident on the 11th of March 2011, the Swiss Federal Council decided to phase-out nuclear energy (FASC, 2011; Leuthard, 2011), resulting in large uncertainties regarding the future of the Swiss electricity supply (see section 2.3).

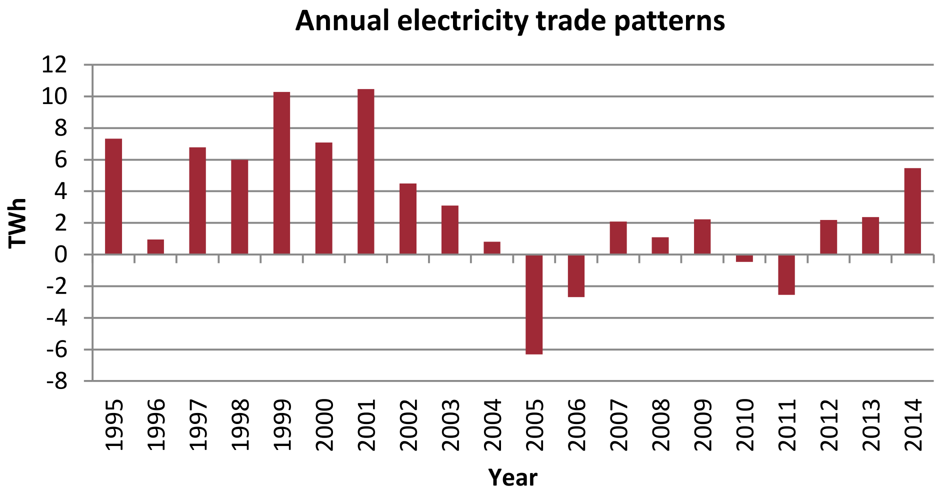


Source: (Bundesamt für Energie, 2014b)

Figure 2-3: Swiss primary energy consumption by energy carrier

The high contribution of hydro generation creates large variations in seasonal electricity output. For example, river hydro output is highest during the summer months (June –

August) and lowest during the winter (see Figure 2-5). This is an inverse behaviour to the electricity demand, which is higher during winter (due to increased lighting and heating requirements) and lowest during summer (see Figure 2-6). These seasonal imbalances create a dependence on imported electricity during certain seasons (see section 2.2). Nevertheless, historically Switzerland has managed to remain self-sufficient[1] on an annual level with respect to supplying its electricity demand, as shown in Figure 2-4. The figure shows that barring a few exceptions (years where numbers are negative indicates net electricity import, i.e. years 2005, 2006, 2010 and 2011) Switzerland is a net exporter of electricity.



Source: (Bundesamt für Energie, 2014a)

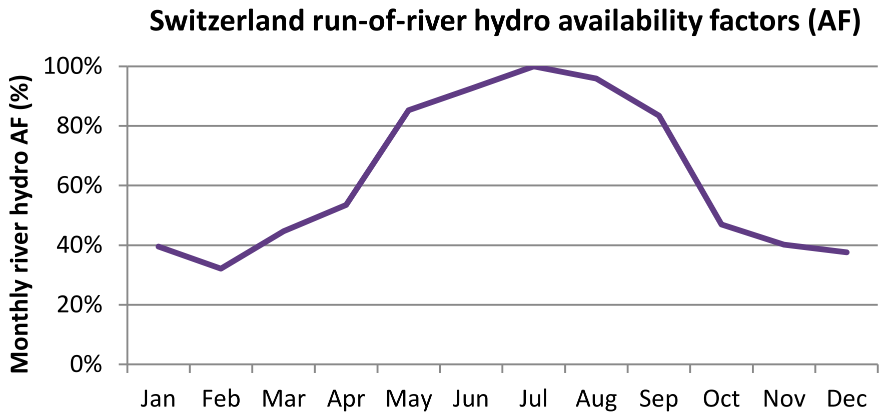
Figure 2-4: Annual electricity trade patterns in Switzerland

2.2 Switzerland in an interconnected world

Electricity trade has a very important role for Switzerland, both in terms of electricity supply / demand balancing, as well as a source of revenue. As mentioned in the previous section, Switzerland has a high share of dam and river hydro based electricity generation (56% in 2014). One of the attributes of hydropower is its seasonality;

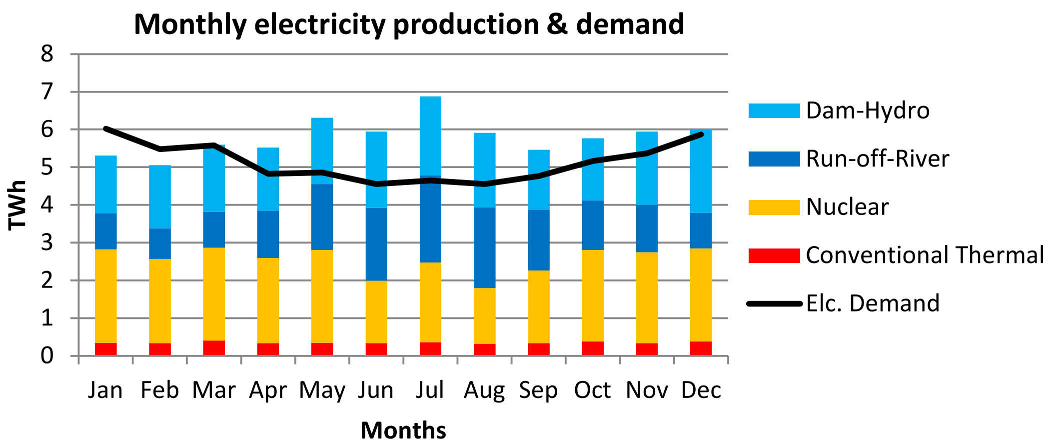
[1] Self-sufficiency implies that there is no net import over the year. There could be seasonal or daily periods of imports, but these are compensated by electricity exports during other hours, thereby resulting in net zero imports or even excess export over the year.

creating large variations in electricity output depending on the time of the year (see Figure 2-5). This coupled with variations in seasonal demands results in a dependence on imported electricity during certain seasons (see Figure 2-6). For example, in 2014, Switzerland was a net importer during the first and fourth quarters of the year by around 0.7 TWh, and a net exporter in the second and third quarters by 6.2 TWh, resulting in an annual export surplus of 5.5 TWh for the year (Bundesamt für Energie, 2014a). This pattern has been constant over the past years, as shown in Figure 2-7, which shows the monthly import/export patterns for the last three years.



Source: (Kannan et al., 2011)

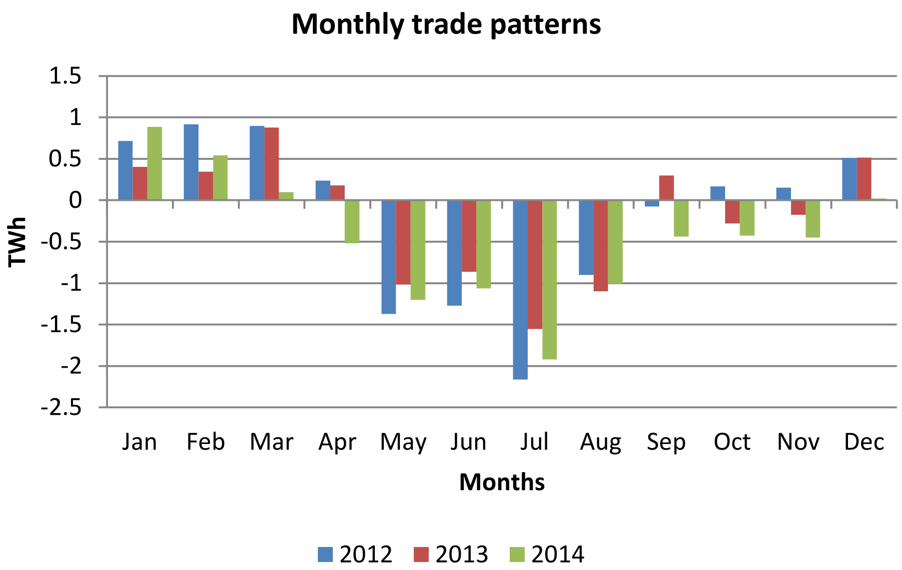
Figure 2-5: Availability of Swiss run-of-river (ROR) plants



Source: (Bundesamt für Energie, 2014a)

Figure 2-6: Monthly electricity production (2014)

Figure 2-7 also shows that exports in summer usually exceed imports in winter. In fact, Switzerland has traditionally been a net exporter of electricity (see Figure 2-4).

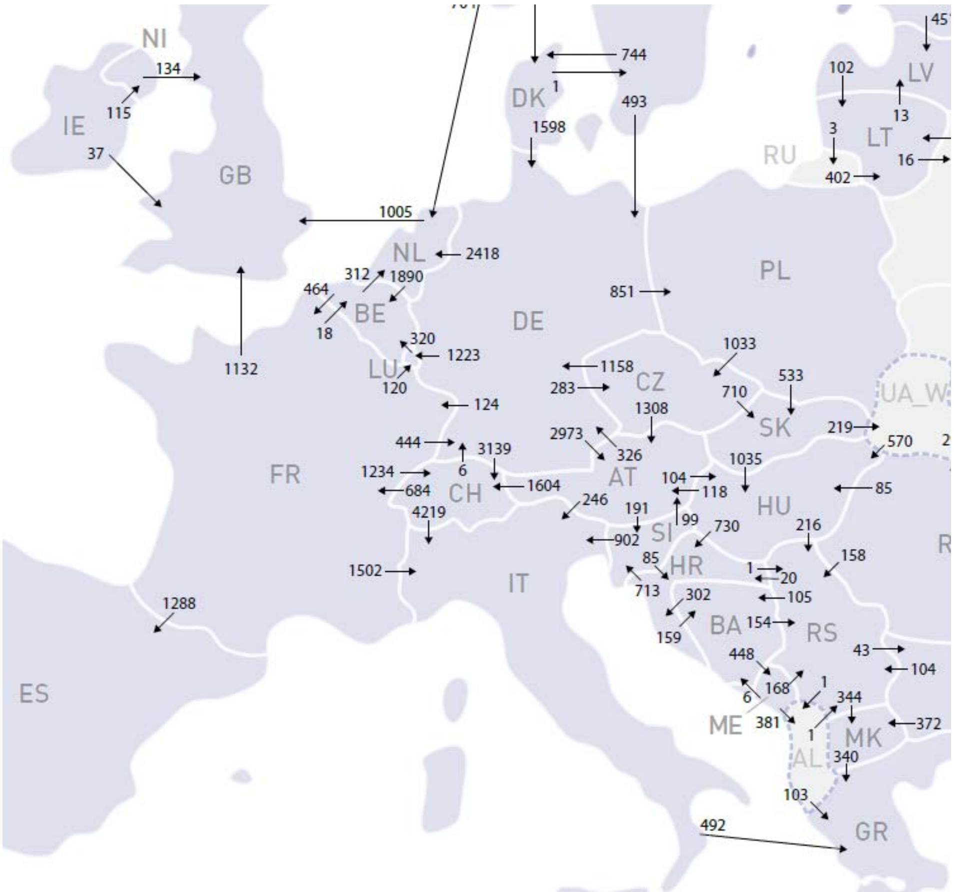


Source: (Bundesamt für Energie, 2014a)

Figure 2-7: Monthly electricity trade patterns

Besides balancing the electricity system from a technical perspective, electricity trading is also a major source of revenue. Most of the current cross-border electricity trading is aimed at exploiting price differentials, especially through the use of large dam and pumped hydro storage to export at peak demands. Swiss power producers have taken advantage of the country's excellent pumped storage capacities such that Switzerland is one of the most important electricity exporters for peak demands (Bundesamt für Energie, 2011; ENTSO-E, 2014), creating surplus revenue[2] while balancing net trade volume.

[2] Net revenue from electricity trading was CHF 442 million in 2014 (for net export of 5.5 TWh). Due to optimization of trade patterns (importing at off-peak hours and exporting at peak demands), Switzerland generates revenue from electricity trading even during years of net electricity imports. For example, net revenue from electricity trading was CHF 1018 million in 2011 (net import of 2.6 TWh), CHF 1328million in 2010 (net import of 0.5 TWh) (Bundesamt für Energie, 2014a, 2014b).



Source: (ENTSO-E, 2015)

Figure 2-8: Load flows (night) on 21.01.2015 at 03.00 a.m CET

Finally, Switzerland also acts as an interconnecting hub due to its ideal positioning between northern and southern Europe, linking the three biggest central European national markets of Germany-Austria, France and Italy (see Figure 2-8 for the load flows through Switzerland in an hour). The cross-border interconnecting capacities (NTC) of Switzerland are around 10 GW, amounting to around 20% of the EU interconnector capacities (ENTSO-E, 2014). As a result, developments in European grid expansions will strongly influence the Swiss electricity system due to its transit role and vice-versa (Schlecht & Weigt, 2014a). Hence, any analysis of the evolution of the Swiss electricity system for the future will have to consider developments in neighbouring countries as well.

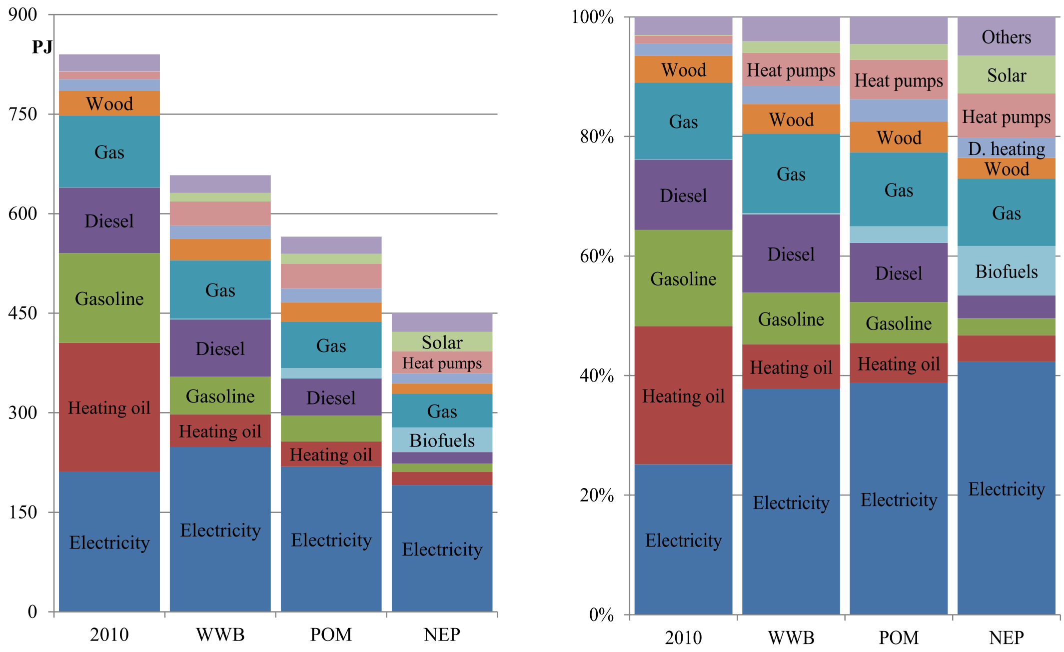
2.3 Future Challenges for the Swiss electricity system

There are a number of challenges associated with the transformation of a Swiss electricity system striving towards sustainability. These challenges can be environmental, socio-political, technical or economical, and some of these challenges are described below.

2.3.1 Swiss electricity demand

The electricity demand of Switzerland has been increasing continuously, reaching a peak value of 59.8 TWh in 2010 (see Figure 2-1). The electricity demand is driven by many socio-economic factors such as GDP growth, population growth etc. There are a number of Swiss specific studies that have demand-side models to determine possible electricity demand scenarios for the future (see section 2.4.1). While almost all the studies project lower overall energy demands, an overwhelming majority of the studies expect a growth in the electricity demand (see Figure 2 in (Densing et al., 2014)).

In September 2012, The Swiss Federal Council of Energy published its "Swiss Energy Strategy (SES) 2050" (PROGNOS AG, 2012), which identified three energy demand pathways namely: WWB – Weiter Wie Bisher i.e. a business as usual scenario; POM – Politische Massnahmen i.e. a scenario with increased energy policy measures; and NEP – Neue Energiepolitik i.e. a more stringent target scenario, with an aim of reducing annual per capita CO_2 emissions to 1 – 1.5 ton CO_2. Figure 2-9 (a) shows the final energy demand by energy carriers for the year 2050 as projected by the Swiss energy strategy. As can be seen from the figure, the final energy demand reduces in all three scenarios, whereas the electricity demand increases from the 2010 level. This is because the scenarios aim at reducing fossil fuel demands in heating or transport sectors by substituting them with electric alternatives such as heat pumps or electric vehicles, which reduce final energy consumptions, but increase the demand for electricity. This is observed more clearly in Figure 2-9 (b), where the share of electricity in total energy demand increases from today's level of about 25% to around 40% by 2050 in all three scenarios. Hence, one of the main challenges facing the Swiss electricity system is to meet this ever increasing electricity demand.



(a) (b)

Figure 2-9: Final energy demand projections for the year 2050 (Swiss energy strategy 2050). Figure (a) shows the absolute energy demand (in PJ) for different energy carriers; Figure (b) shows the contribution of each energy carrier relative to the total energy demand.

2.3.2 Swiss nuclear phase-out and climate policies

As mentioned in section 2.1, around 32% of the Swiss electricity generation in 2014 was from nuclear power. Public perception in Switzerland regarding nuclear has always been mixed, ranging from positive in the 1960's to overwhelmingly negative by 1990, when a ten year moratorium on new plant construction was put into effect following a national referendum. Around 1/3rd of the nuclear capacity is expected to be retired by 2020 (assuming a 50 year lifetime). This combined with the ending of long-term electricity import contracts with France, was expected to create an electricity supply shortfall by 2020 (World Nuclear Association, 2014d). Nuclear power was one of the options touted to fill this supply gap. In November 2010, the Swiss Federal Nuclear Inspectorate (ENSI) provided a positive feedback regarding the construction of three new replacement nuclear power plants on existing nuclear sites in Mühleberg, Beznau and Niederamt ((ENSI), 2010).

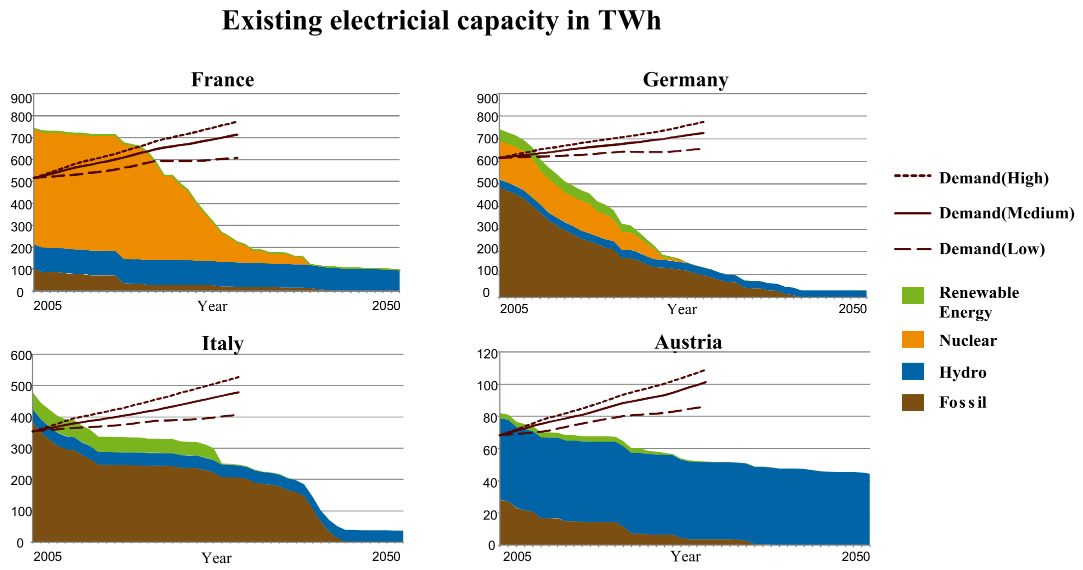
A few months later, on the 11th of March 2011, the Fukushima Daiichi nuclear disaster led to a large social and political outcry against nuclear power throughout Europe. Effects of this opposition campaign also reverberated high in Switzerland, which eventually resulted in the Swiss Federal Council decision to phase-out nuclear energy (FASC, 2011; Leuthard, 2011). Assuming a 50 year lifetime for each plant, this would mean that the last nuclear plant (NPP Leibstadt) would go offline in 2034. This current nuclear phase-out policy would create an electricity supply gap of around 35% - 45% by 2035, depending on the demand assumptions (WWB and NEP respectively).

On top of the nuclear phase-out policy, there are several energy and climate policy targets that Switzerland has set for itself. For example, Switzerland strives to reduce its total greenhouse gas (GHG) emissions by 16% by 2020, and 50% by 2030 (Tagesschau, 2015; UVEK, 2015). Emphasis has been given to energy efficiency measures in the residential, industrial and service sectors, promoting increased electrification of transport (via electric and hybrid vehicles) and heating (via heat pumps, CHP plants etc.) sectors, encouraging investments in renewable energy, and increasing CO_2 taxes on fossil fuels (PROGNOS AG, 2012). As mentioned in section 2.3.1, while the ultimate aim is to reduce fossil energy consumption, electricity demand is expected to increase in the long run (see Figure 2-9).

2.3.3 European energy policies

Similar to the nuclear phase-out policy in Switzerland, neighbouring countries in Europe also face challenging times to secure a sustainable supply of electricity. Many countries have existing base-load fossil or nuclear power plants that are nearing retirement and need to be replaced. Figure 2-10 shows the expected capacity retirement of existing power plants in the four neighbouring countries of Switzerland (Axpo, 2009). The manner in which these capacities are replaced will have far reaching consequences for the Swiss electricity system as well. There are several European energy and climate policy targets that would guide the future evolution of the electricity sector in the neighbouring regions.

The European Union (EU) has set itself very ambitious targets in reducing its greenhouse gas emissions and to create a more sustainable, competitive and secure energy system by 2050. These targets are based on four major pillars namely: energy efficiency, renewable energy, nuclear energy and carbon capture and storage (CCS). Besides the climate change mitigation aspect, the new energy strategy also aims at ensuring a stable and abundant supply of energy by reducing its import dependency on fossil fuels (European Commission, 2015).



Source: (Axpo, 2009)

Figure 2-10: Electrical capacity retirement in neighbouring regions of Switzerland

In March 2007, the European commission announced "The 2020 climate and energy package[3]" (European Commission, 2007), a set of binding legislations to ensure the EU meets three key objectives for the year 2020. The objectives are known as 20-20-20 targets, and aim to:

- Reduce the EU GHG emissions by 20% from 1990 levels
- A minimum of 20% of EU energy demand to be supplied by renewable resources
- Improve the EU's energy efficiency by 20%

[3] Also referred to as the 20-20-20 targets.

According to estimates in 2014, Europe is well on course to meet its 20-20-20 targets. GHG emissions have reduced by around 19% of 1990 levels, while the share of renewables in the gross final energy consumption is around 15.3%. Energy savings in 2020 are expected to reach 18% – 19%, missing the target by 1% – 2%, but could be met if all countries implement existing legislation (European Commission, 2015).

In October 2014, EU leaders announced the “2030 framework for climate and energy policies”, which set out targets beyond 2020. According to the new framework, GHG are to be reduced by 40% of 1990 levels by 2030, with renewable share and energy efficiency targets revised to 27% by 2030 (European Commission, 2014).

For long term perspectives, the European commission published its “Roadmap for moving to a low-carbon economy in 2050” in December 2011. The roadmap envisages a competitive low-carbon economy by 2050, cutting GHG emissions by 80% in 2050 compared to 1990 levels. The roadmap foresees the power sector to have the biggest potential for reducing emissions, with a complete decarbonization of the electricity sector in Europe possible by 2050 (European Commission, 2011). Electricity would also partially replace fossil fuels in heating and transport applications.

Energy security is another primary concern within the European Union. The EU imports more than half of its energy consumption, especially crude oil (more than 90%) and natural gas (more than 60%). Many countries rely on a single source of supply (e.g. relying on Russia for natural gas imports), leaving them exposed to geopolitical and economic instabilities in the energy exporting countries (European Commission, 2015). The Energy Security Strategy proposed by the European Commission in May 2014 aims to protect member countries from such vulnerabilities. Besides efficiency improvements and increased generation from domestic renewable sources and nuclear power, a lot of emphasis has been put on creating an internal energy (especially electricity) market in Europe. Market liberalisation would ensure increased competition between the electricity suppliers as well as increase cross border trade between countries. “Market coupling” is one of the major steps towards the realisation of this liberalised European market. Market coupling optimises the use of existing cross-border electricity interconnector capacities by merging the markets for energy and capacity to form a coupled electricity market. It maximizes social welfare, avoids market splitting and promotes investment in cross-border transmission capacities (EPEX, 2015). By February 2015, the coupled area in Europe (referred to as the Multi-Regional Coupling) encompasses 19 countries, covering 85% of European power consumption (EPEX, 2015). Switzerland is not yet integrated into this new coupled European power market, and the Swiss Federal Council has launched a consultation procedure with respect to the liberalisation of the power market by 2018, with the aim of integrating the Swiss power market into the European electricity market (Swiss Grid, 2014).

Finally, Nuclear power is seen as a viable and attractive low carbon alternative by the European Commission and the International Energy Agency (IEA, 2015). In fact, a “nuclear renaissance” was expected to decarbonise the electricity sector in the medium- to long term future. But as discussed previously with respect to Switzerland (see section 2.3.2), the nuclear revival came to a shuddering halt in many European countries after the Fukushima nuclear accident (Wittneben, 2012). Germany, which until March 2011 produced a quarter of its electricity from nuclear energy, immediately shut down eight of its oldest reactors (around 8.3 GW of 20.3 GW installed nuclear capacity), with the remaining nine reactors to be shut down by 2023 (World Nuclear Association, 2014b). Italy had begun discussions to produce 25% of its electricity supply from nuclear power by 2030, but decided to continue with its nuclear moratorium after a referendum in June 2011 (World Nuclear Association, 2014c). France, a traditional nuclear powerhouse with over 75% nuclear based electricity generation, also faces political problems in terms of expanding or replacing their existing nuclear fleet (Maïzi & Assoumou, 2014). The current government had proposed to reduce the share of nuclear to 50% of the total electricity generation by 2025 (ÉLYSÉE, 2012). Although nuclear power could be an attractive low-carbon alternative, different countries have adopted very different policies regarding nuclear pathways depending on their socio-political environments.

2.3.4 Alternative electricity supply options for Switzerland

All these energy and nuclear policies in Switzerland and Europe discussed above have left Switzerland with a select choice of supply options for its future electricity system.

The Swiss energy strategy (SES 2050) (discussed in section 2.3.1) identified three electricity demand pathways as well as a number of supply variants. The demand pathways depend on socio-economic drivers, efficiency improvements, behavioural changes and so on. At the electricity supply side, the choice is effectively limited to three options in SES 2050 namely; natural gas[4], renewable resources and imported electricity. Each of these options have positive and negative attributes with respect to economic, environmental, technical and social aspects, as illustrated in Figure 2-11. For example, replacing nuclear plants with natural gas power plants could be a simple solution from a technical and economical perspective. However, this option would entail issues related to climate change mitigation (due to CO_2 emissions), and supply security concerns (due to increasing imports of natural gas). Renewable based electricity generation are particularly useful for meeting climate change objectives, but the intermittent nature of solar or wind technologies would create additional problems with respect to supply-demand balancing. These technologies are also relatively capital intensive compared to conventional fossil power plants, especially when considering the need for additional modifications to the grid system as well as backup systems (storage of flexible power plants) to cope with the intermittency issues. Finally, for the imported electricity option, sources and availability of electricity are highly dependent on developments in neighbouring countries, while at the same time raising concerns for supply security.

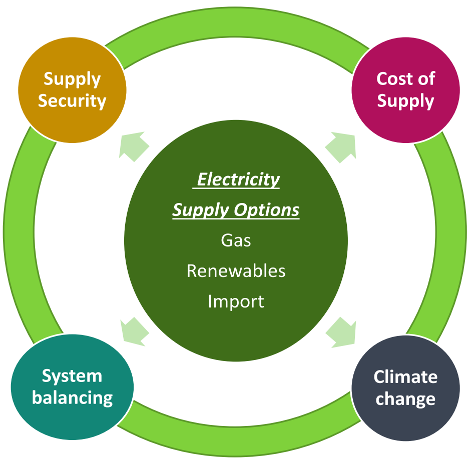


Figure 2-11: Electricity supply options for Switzerland

[4] Centralised production via Combined Cycle Gas Turbines (CCGT) and/or decentralised production via Combined Heat and Power (CHP) systems

Hence, while there is no single perfect replacement for the outgoing nuclear plants, a combination of two or more of the above options could provide a satisfactory alternative. The next section describes the various studies that have explored on how to combine these alternative supply options, what the shortcomings in the studies are, finally leading to the motivations behind developing a new analytical framework for the Swiss electricity system.

2.4 Overview of existing models

There are several Swiss specific studies that try to evaluate the evolution of the Swiss electricity system in future. There also exist many European models that deal with the expansion of the electricity network in Europe. This section provides a review of some of these existing analytical tools, and their strengths and shortcomings.

2.4.1 Overview of Swiss energy models

Several Swiss specific analytical tools have been developed to analyse the future evolution of the Swiss electricity system. Each of these models has its own specific strengths and weaknesses. The scopes of these models vary in terms of their technology representations, temporal details, macro-economic details etc.

There are the top-down general equilibrium (CGE) models that focus on the macro-economic aspects with limited/aggregated or no representation of technologies. CGE models of Switzerland include the GENESwIS model by Econability (Vöhringer, 2012), the CITE model developed by the Centre of Economic Research at ETH (Bretschger & Ramer, 2012), CEPE model by the Centre for Energy Policy and Economics at ETH (Imhof, 2012), SWISSGEM_E developed by ECOPLAN (Bundesamt für Energie, 2012). The focus of these models is on the impacts of various policies and market mechanisms on the economy and social welfare. All of the above-mentioned models deal with the entire energy system (not just electricity sector), and are perfect foresight models with a long time-horizon (except the CEPE model). However, technology data is usually highly aggregated, with very limited intra-annual details, which make them unsuitable for analysing intermittency issues of variable renewable technologies such as solar photovoltaic (PV) and wind.

There are also numerous bottom-up models, which have a much better representation of technological characteristics. Examples of Swiss bottom-up models include SwissMod by FoNEW Basel (Schlecht & Weigt, 2014b), ETEM by (Babonneau et al., 2012; Operations Research Decisions and Systems, 2011), SMM by Paul Scherrer Institute (Weidmann et al., 2012), ZEPHYR by Pöyry (VSE, 2012), “Energiezukunft Schweiz” model by the Energy Science Centre at ETH (Andersson et al., 2011), SCS Energiemodell by SCS Supercomputing Systems AG (Super Computing Systems (SCS), 2013), Mesap/PlaNet by DLR and used by Greenpeace for Switzerland (Teske & Heiligtag, 2013), ENERPOL by the Laboratory for Energy Conversion, ETH (Singh et al., 2014) and finally the model developed by PROGNOS for the Swiss Energy Strategy 2050 (PROGNOS AG, 2012).

SwissMod, ENERPOL and the SCS Energiemodell are dispatch models (see section 3.2 in Chapter 3) with very high inter-annual detail (hourly or quarter-hourly). These models are aimed at analysing dispatchability of electricity generation technologies through optimization or simulation frameworks. However, they do not consider investment decisions or capacity expansion due to their shorter time horizon (1 – 5 years). Other models like the ones from PROGNOS, VSE and Greenpeace consider long-time horizons, but the generation mix is largely given exogenously, depending on scenario assumptions (PROGNOS AG, 2012; VSE, 2012). Models such as the Swiss MARKAL Model (SMM), Energy Technology Environment Model (ETEM) and the ETH/ESC model are capacity expansion models where the generation mix is optimised on a cost basis over a long time-horizon. These long term planning models however do not capture intra-annual variability in renewable resources due aggregated intra-annual representation. This could lead to suboptimal investment decisions, with overestimation of renewable penetration and/or underestimation of storage or flexible capacities required to balance the system, which implies an underestimation of total system costs (Poncelet, Delarue, et al., 2014a).

In order to understand the evolution of the electricity sector, it is important to understand investment cycles (i.e. capacity expansion) as well as variability in supply. But in reality, combining both dimensions is challenging on several aspects such as computational complexity, data availability etc. (Connolly et al., 2009; Kannan &

Turton, 2013). The Swiss TIMES electricity model (STEM-E) developed at PSI (Kannan et al., 2011) was the first attempt at combining these feature for a Swiss model. The model has a very detailed depiction of the Swiss electricity system and has enabled the understanding of plausible transition pathways for the electricity sector (Kannan & Turton, 2012).

Figure 2-12 gives an overview of all the Swiss models discussed in this section. Two major reviews have been undertaken to compare these various modelling approaches. Dr. Nicole Mathys compares various CGE models as well as the SMM and ETEM models (Mathys et al., 2012). Another review carried out by Dr. Martin Densing from PSI compares various bottom-up models (Densing et al., 2014).

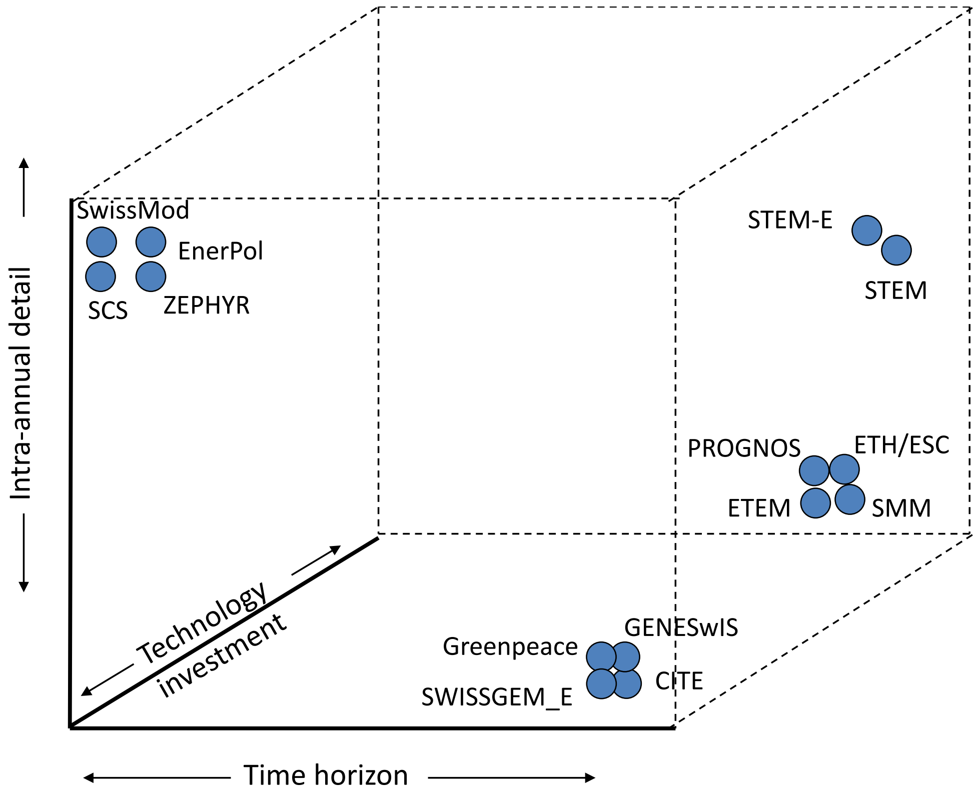


Figure 2-12: Swiss energy and electricity modelling approaches

Despite all the strengths and weaknesses of the various models described above, one limitation is common across all the modelling approaches including STEM-E. All the above mentioned models (except for the ZEPHYR model from VSE) are aggregated national models of Switzerland, with no or highly simplified representations of the electricity import/export with neighbouring countries. As discussed in section 2.2, electricity trade plays an important role in electricity system balancing, and all the aforementioned studies expect it to continue in the future. In fact, several studies consider net import scenarios for Switzerland in the long run. However, such single region models do not consider the source for import or a market for export, instead assuming that imports / exports are available whenever required. These models fall short when addressing uncertainties associated with the technology deployment in neighbouring countries, which will affect electricity trading patterns in future. Such uncertainties can be captured in models where neighbouring countries are also represented in detail, and hence there is a strong rationale in developing a multi-region electricity system model that represents Switzerland and its neighbours.

2.4.2 Overview of European energy models

While the impetus to develop a multi-region model has been explained in the previous section, there are already numerous technology rich European energy and electricity models that deal with similar issues. As discussed in the earlier subsection, each of these models has its own objectives and applications. From a methodological perspective, they can be differentiated in terms of short-term vs long-term optimization, capacity planning vs plant dispatch or operational planning etc. For example, models such as REMIx (DLR, 2008) and EPOD (Johnsson, 2011) are dispatch type models that optimise the operation of the power system and deal with intermittency of renewable sources in detail. However, such frameworks do not include capacity expansion planning over longer time-horizons, i.e. future capacities are given exogenously. On the other hand, models such as the EU-TIMES from JRC (Simoes et al., 2013), TIMES-PEM from IER Stuttgart (Blesl et al., 2010) EIREM (Hoster, 1998), EuroMM from PSI (Reiter, 2010), ELOD (Johnsson, 2011), ATLANTIS (Gutschi Ch., 2009) and ELIN (Kjärstad et al., 2013) have limited intra-annual depiction making them less suitable for capturing variability in renewable based electricity generation (see Figure 2-13). As was the case with Swiss models before, combining a high level of intra-annual details and long time-horizons in a technologically explicit model at the EU level would be complex and computationally challenging to solve (Connolly et al., 2009; Johnsson, 2011; Pfenninger et al., 2014; Welsch et al., 2014). Certain studies use a combination of long-term and short-term model through soft-coupling to generate insights, e.g.

application of ELOD and EPOD models (Johnsson, 2011).

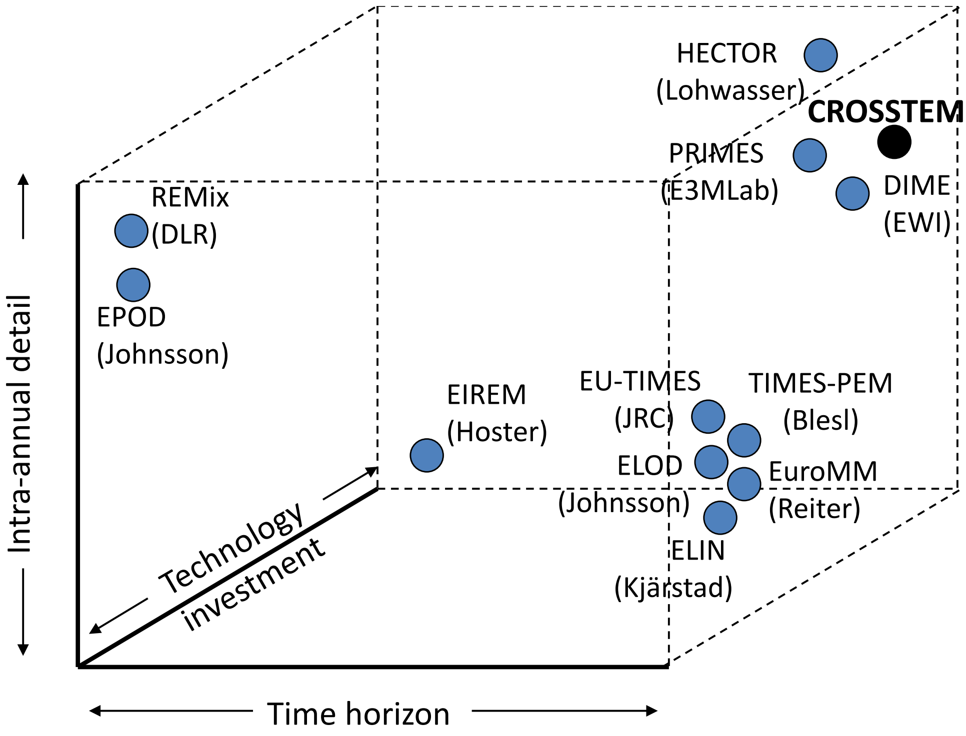


Figure 2-13: European energy and electricity modelling approaches

Frameworks such as the DIME model (Energiewirtschaftliches Institut (EWI), 2008) or HECTOR (Lohwasser & Madlener, 2009) and the PRIMES model (E3MLab/ICCS, 2014) overcome this limitation by having an enhanced intra-annual resolution on long-term models, similar to STEM-E. But all the aforementioned EU models have limits in addressing Swiss specific issues due to their highly aggregated or simplified representation of Switzerland. Therefore, there is a need to have an analytical tool with an adequate representation of the Swiss electricity system and wider EU markets. This is the motivation behind creating the new modelling framework discussed in this thesis.

2.5 Motivation

The objective of this doctoral thesis is to generate insights into transition pathways for the Swiss electricity system in the medium and long term future, in conjunction with developments in the electricity sector of the four bordering countries namely: Austria (AT), France (FR), Germany (DE) and Italy (IT). Together, these five countries account for over half of the total electricity generation in Central and Western Europe (ENTSO-

E, 2014). With a framework consisting of these five regions, we try to answer some specific research questions which include:

- How would the Swiss electricity sector evolve under various scenario conditions?
- Quantify the extent to which policies and climate change mitigation goals in neighbouring countries influence the Swiss electricity sector?
- Which conditions – in terms of infrastructural and technological developments – would be more likely to support a stable and secure supply for Switzerland?
- What would be the cost of moving towards a decarbonised renewable electricity generation mix?

In order to answer the above questions, the Cross-border Swiss TIMES electricity model (CROSSTEM) has been developed. Two additional models – the European Swiss TIMES Electricity model (EUSTEM) and the CROSSTEM-Hourly generation model (HG) have also been developed to complement and complete the CROSSTEM framework. The methodology and detailed description of the CROSSTEM model is provided in the next chapter. The EUSTEM model is covered in Chapter 6 and CROSSTEM-HG in chapter 7.

3 The Cross-border Swiss TIMES Electricity modelling framework

This chapter details the methodology of CROSSTEM. The chapter begins with a brief overview of the concept of energy system models and their applications, as well as the different types of modelling approaches that are used specifically for electricity sector. This is followed by a description of the TIMES modelling framework, based on which CROSSTEM is developed. A detailed explanation of the model structure and inputs used in the CROSSTEM model is described in the subsequent sections of the chapter.

3.1 Introduction

The development and evolution of the Swiss energy and electricity market depends on a number of issues, many of them already described in Chapter 2. As such, predicting the future electricity demand and supply mix is a near-impossible task, due to the complex interactions in the energy sector, as well as highly uncertain parameters such as population and economic growth, liberalisation of electricity markets, environmental considerations, international energy prices etc. However, long-term strategic energy planning is required to prepare countries for the coming decades, the importance of which was revealed particularly in the aftermath of the global oil crisis in 1973 (Energy

Modelling Forum, 1977). Since then, energy system models have been developed to systematically analyse the different interactions in the energy and economy sectors via scenario analysis. The aim of these models is to provide insights and help policy makers to shape their opinion of the directions the energy sector should follow in order to achieve given policy targets (Pfenninger et al., 2014). The next section reviews some of the existing electricity modelling approaches and the issues they aim to address.

3.2 Electricity modelling approaches

Models can broadly be classified as Top-down or Bottom-up models. Top-down models (or more commonly referred to as CGE – computable general equilibrium models) focus on the macro-economic aspects with limited/aggregated or no representation of technologies. The focus of these models is on the impacts of various policies and market mechanisms on the economy and social welfare. Bottom-up models on the other hand are used to conduct a more disaggregated analysis of energy technologies and often focus on the microeconomic impacts and detailed analysis of the techno-economic dimensions of specific policy options (IPCC, 2001). Bottom up models are better suited for the type of analysis that is intended to be carried out in this dissertation.

(Foley et al., 2010) gives a strategic review of various types of bottom-up electricity models and their applications. Electricity system models can be differentiated based on the type of issues that they try to address. For example, they are distinguished with respect to the timescales that are considered. Dispatch/Unit commitment models focus on the electricity grid and temporal variations and have a timescale that varies between minutes/hours (used for determining economic dispatch, power flows etc.), to hours/days/weeks (for weekly/seasonal unit commitment planning) (Foley et al., 2010). All of these are so-called operational models, and are in stark contrast to planning models, which usually have time-horizons spanning years/decades and are used primarily for capacity expansion planning, scenario analysis, production cost modelling, forecasting etc. (Pfenninger et al., 2014).

Finally, the planning models can further be differentiated into simulation/forecasts models and optimization/scenario models. Optimization models are generally linear programming models (although non-linear and mixed integer problems are also seen in the literature) that optimise the total system over one or more selected variables (i.e. system costs, emissions etc.). These models give an indication of possible evolutions of the electricity system via a series of “what-if” scenarios. Simulation models on the other hand do not necessarily optimise for a certain variable, and can be an amalgamation of various submodules, some of which could include optimization models. Instead of generating possible future scenarios, simulation models focus more on the interaction between various components of the system for fixed targets (Pfenninger et al., 2014).

One of the main disadvantages of these long-term capacity expansion planning models is their limited representation of intra-annual details. This is not a big issue when dealing with baseload or flexible generation units whose output can be controlled, as has been the case in the past. However, its weaknesses are exposed when dealing with highly intermittent renewable technologies such as solar PV or wind. For example, representing a year in 6 time slices[5] can create to suboptimal investment decisions with respect to intermittent renewables. It leads to considerable overestimation of renewable technologies, as well as underestimation of flexible backup and storage technologies required for balancing the system (Poncelet, Delarue, & D'haeseleer, 2014; Poncelet, Delarue, et al., 2014b).

In order to understand the long-term development of the Swiss electricity sector in the future, an analytical tool is required that can consider long-time horizons (to account for long-term policy issues and transitions in the electricity sector) while at the same time being able to represent sufficient intra-temporal detail to account for shorter-term (i.e. hourly, seasonal) variations in electricity supply, demand and imports/exports. As mentioned previously in section 2.4 of Chapter 2, combining characteristics of operational models with planning models is complex and challenging. The TIMES framework is one of the analytical frameworks that has the possibility to combine some of the features mentioned above (Kannan et al., 2013), and therefore has been chosen for this thesis. An overview of the TIMES framework is given in the next section.

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[5] The Swiss MARKAL Model has an intra-annual time resolution of 6 timeslices namely base-load and peak-load for three seasons (summer, intermediate and winter).

3.3 Analytical Framework

The analytical framework used to develop the CROSSTEM model is TIMES (**T**he **I**ntegrated **M**ARKAL[6]/**E**FOM[7] **S**ystem framework) (Loulou et al., 2005). TIMES is a perfect foresight, cost optimization modelling framework, which identifies the "least-cost" combination of technologies and fuel mix based on the operational characteristics and availabilities of the technologies, to satisfy exogenously given energy (or in this case electricity) demands. Technology characteristics such as investment costs, operational and maintenance costs, fuel resource costs and availability, energy conversion efficiencies, renewable resource potentials, availability factors, construction times[8] / costs, decommissioning costs etc. can be incorporated into the model (Loulou et al., 2005). TIMES allows for prospective analysis on a long time horizon (50+ years), while at the same time being able to represent a high level of intra-annual detail in demand and supply (e.g. load curves). It also has an enhanced storage algorithm compared to its predecessor MARKAL, enabling the detailed modelling of electricity storage systems (ETSAP, 2008). The TIMES framework is particularly suited to explore possible energy futures based on contrasted "what-if" scenarios.

As mentioned previously, TIMES is a cost-optimization framework that configures an energy system over a certain time horizon by minimizing the total discounted system cost (or in other words maximising the consumer surplus of the system). The discounted total system cost is the objective function of TIMES, and it is an aggregation of capital costs, fixed and variable operation and maintenance costs (FOM and VOM), fuel costs, decommissioning costs, taxes, exogenous import costs, revenues from exogenous exports, subsidies and salvage values of processes and commodities, for the entire time horizon, and discounted to a selected base year. The basic structure of the optimization approach can be described as shown in Figure 3-1.

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[6] MARKAL – **MARK**et **AL**location.
[7] EFOM – **E**nergy **F**low **O**ptimisation **M**odel
[8] Also referred to as lead time. It is defined as the "time between the commencements of licensing process to the date of commercial operation", with investment spread across several years (Loulou et al., 2005).

Minimise

Objective function

$$NPV = \sum_{r=1}^{R} \sum_{y \in years} (1 + dr_{,y})^{REFYR-y} \times ANNCOST(r, y)$$

where:
NPV – is the net present value of the total system (the TIMES objective function)
ANNCOST – is the total annual cost in region r and year y
dr,y – is the general discount rate
REFYR – is the reference year for discounting
YEARS – set of cost incurring years, including past investments, cost within the time horizon, and costs after the end of horizon (EOH).

by ensuring that

Balance equation

$$\sum_{t=1}^{T} \sum_{k \in technology} CAP_{k,}(t) \geq DM(t)$$

where:
CAP – are the capacities of end use technologies
DM – is the exogenous demands to satisfy

and subject to

Constraints

On energy carriers
- Potential (for renewable resources)

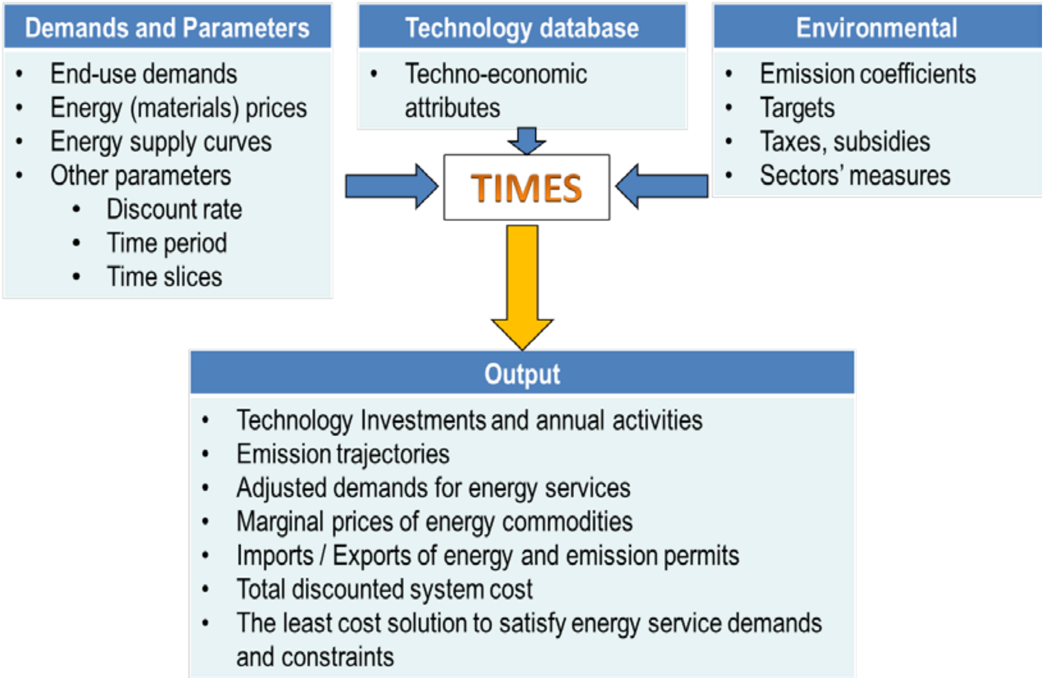
On technologies
- Growth constraints on technology deployment; technical availability; efficiency; construction times

On the energy system
- Minimal reserve capacity in power generation; availability of carbon capture and storage (CCS) and storage technologies

Additional constraints by scenario assumptions

Figure 3-1: Modelling approach – objective function, balance equation and constraints

The evolving techno-economic attributes along with the input and output energy commodity prices determine changing cost-benefit conditions over time, eventually resulting in a ranking of energy supply technologies. This ranking along with the demands that have to be met determine which technology is competitive, marginal or uncompetitive, thereby producing the final generation mix (Gargiulo, 2013). An overview of the TIMES framework is shown in Figure 3-2.



Source: (Gargiulo, 2013)

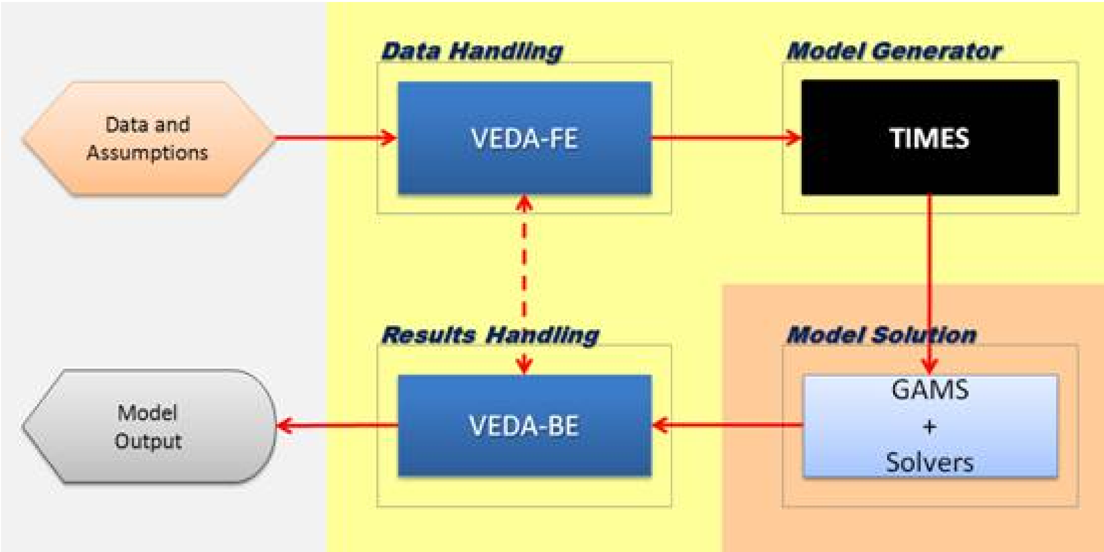
Figure 3-2: TIMES model flow diagram

The next section describes the application of the TIMES modelling framework to develop CROSSTEM.

3.4 CROSSTEM model development

The Cross border Swiss TIMES electricity model (CROSSTEM) was developed using a TIMES input data interface known as VEDA (Versatile Data Analyst). The data flow of the VEDA interface is shown in Figure 3-3. Data and scenario assumptions are fed into the TIMES model generator via the VEDA-Front End (FE), which converts inputs from Excel files to a GAMS[9] (GAMS Development Corporation, 2016) readable format. The TIMES equations are solved in the GAMS environment with the CPLEX solver (IBM ILOG, 2016), producing a text output which is imported in the VEDA-Back End (BE) to analyse model outputs (Kanors, 2008).

[9] GAMS – General Algebraic Modelling System



Source: (Kanors, 2008)

Figure 3-3: VEDA system for TIMES modelling

3.4.1 Model structure

The basic model structure consists of the number of regions, time horizon, number of inter-annual time slices, currency units etc. which are described in the following subsections.

3.4.1.1 Regions

CROSSTEM is an extension of the STEM-E model (Kannan et al., 2011), and covers the whole electricity system of Switzerland (CH) and its four neighbouring countries, viz. Austria (AT), France (FR), Germany (DE) and Italy (IT). In addition to these countries, there is an implicit external region termed “Fringe”, which represents the neighbouring countries of the CROSSTEM regions (see Figure 3-4). This region is defined to account for the electricity trade between the CROSSTEM countries and their neighbours (e.g. electricity trade of Germany with Denmark, Poland, etc.). It also accounts for imports and exports of energy commodities (e.g. natural gas, uranium).

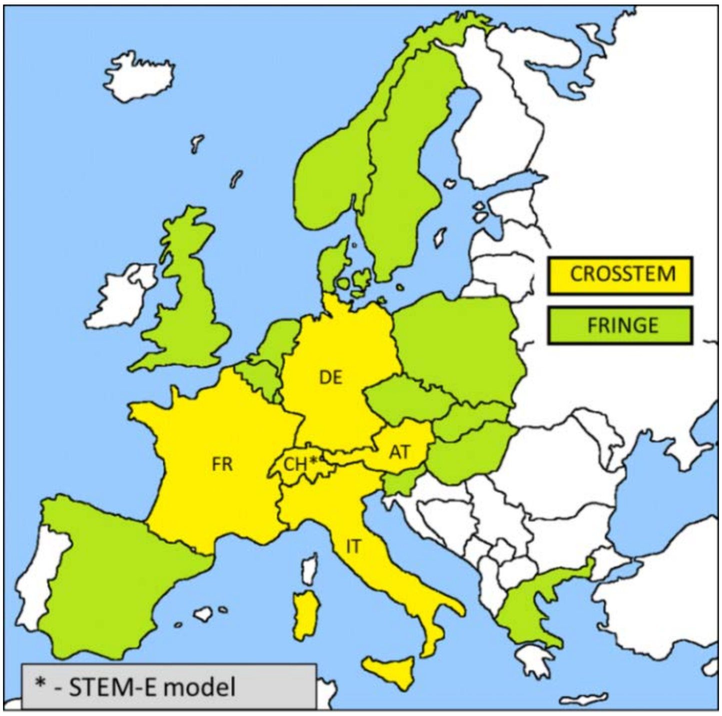


Figure 3-4: CROSSTEM and "FRINGE" regions

3.4.1.2 Time Horizon

CROSSTEM has a time horizon of 60 years (2010-2070)[10] divided into 14 time periods of unequal length. The first two periods consist of one (2010) and two (2011-2012) years respectively for model calibration purposes, while the rest of the time horizon has 12 five-year periods (see Table 3-1). All years within a time period are considered identical, with all the quantities (capacities, commodity flows, operating levels etc.) applying to each year in the period. The only exception is new capacity investments which is made only once in a period (Loulou et al., 2005). The middle year of a time period is known as the milestone year and results are displayed for these milestone years. For example, the milestone year 2015 represents the time period 2013-2017 (see Figure 3-5 and Table 3-1). The TIMES framework is flexible to modify the length of the periods and milestone years.

[10] The model horizon extends up to the year 2070, so as to minimize "end-of-horizon" effects for the year of interest 2050. It is possible that investments may not be made during the final years of the model due to approaching the end of the modelling horizon, resulting in a bias in results.

Table 3-1: Modelling time horizons in CROSSTEM

Period Number	Period length (years)	Actual time periods	Milestone Year
1	1	2010	2010
2	2	2011-2012	2011
3	5	2013-2017	2015
4	5	2018-2022	2020
↕	↕	↕	↕
14	5	2068-2072	2070

3.4.1.3 Time slices

In addition to time periods, the model also has time divisions within a year, and these are known as (intra-annual) time slices (see Table 3-2). The CROSSTEM model represents 4 seasons in a year (Spring, Summer, Fall and Winter) and three different types of days in a week (Weekdays, Saturdays and Sundays), to model the variations in electricity demand and supply patterns of the regions (see also (Kannan et al., 2011)). Each day is further split into 24 hours, thereby enabling the representation of hourly load-curves for demand and supply (see Figure 3-5). Thus the 8760 hours of a year are represented in the model with 288 typical/representative hours/time slices.

Table 3-2: Definition of seasonal and inter-annual time slices in CROSSTEM

Seasonal	Weekly days	Diurnal hours
Summer (SUM-): June – August Spring (SPR-): –March - May Winter (WIN-): December - February Fall/Autumn (FAL-): September - November	Weekdays (WK-): Monday – Friday Saturdays (SA-): Saturdays Sundays (SU-): Sundays and Swiss national holidays	D01, D02, D03 ………………... D24

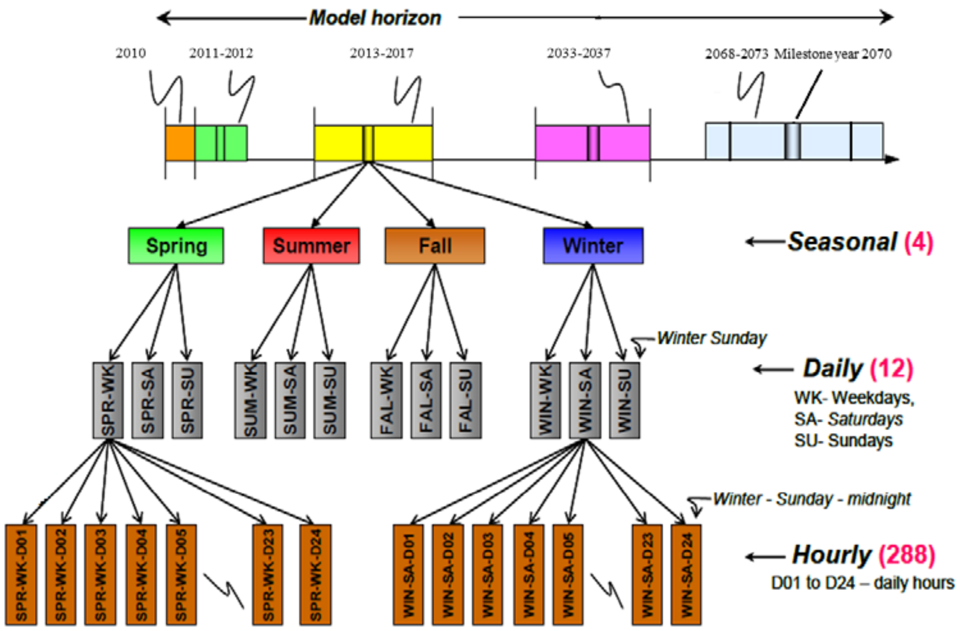


Figure 3-5: Intra-annual details in CROSSTEM

3.4.1.4 Currency Unit

As mentioned in section 3.3, the objective function of the model is the discounted sum of all the annual electricity systems costs over the entire time horizon (discounted to the base year 2010). All cost data is given in Swiss francs 2010 (CHF_{2010}).

For the analysis presented in this report, a discount rate of 4.5% has been used for the entire model horizon, in accordance with the discount rate used for the ELECTRA project (see Chapter 4). This discount rate is used to calculate the annuities on capital investments, as well as to discount the future costs. Technology specific discount rates can be applied, but have not been used for this thesis. The discount rate is a parameter for future sensitivity analysis.

3.4.2 Reference Energy System

A reference energy system (RES) connects all the different elements in the electricity system, from primary energy resource supply to end use electricity demand, and is represented in CROSSTEM for each region. There are around 200 energy technologies[11] interconnected by more than 60 energy and emission commodities[12] to define the whole electricity system. The technologies in the model include a range of electricity generation technologies (power plants), interconnectors for electricity trade between regions, ad-hoc electricity distribution grid, storage technologies (pumped hydro storage, battery and seasonal storage), etc. Commodities range from primary energy resources (natural gas, oil, hydro etc.) to end use electricity demands and CO_2 emissions, which interconnect the various technologies. Figure 3-6 shows a representative RES of CROSSTEM.

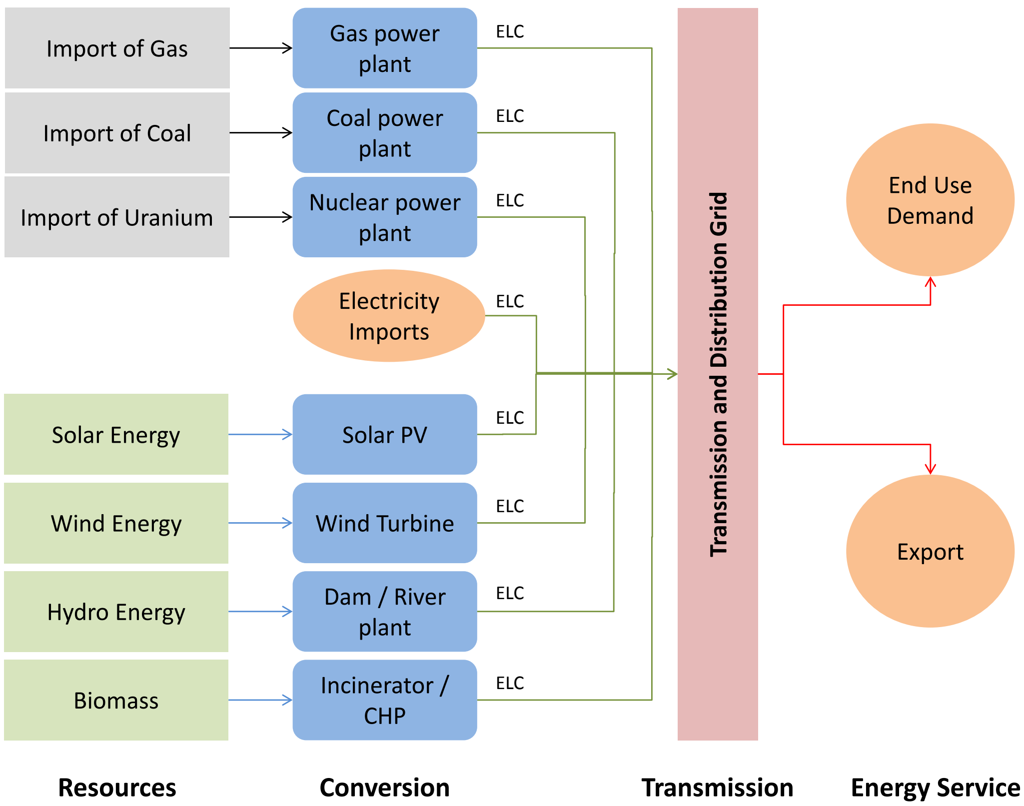


Figure 3-6: Illustration of the Reference Energy System (RES) in CROSSTEM[13]

[11] Process technologies in TIMES include a range of technologies that are classified into the following groups according to their role in the energy system: Electric power plants (ELE), Storage plants (STG), inter-regional exchange (IRE), demand devices (DMD), renewables (RNW), mining (MIN), imports/resources (IMP).

[12] Commodities can also be classified as: energy (NRG), emissions (ENV), demand (DEM), material (MAT) and financial (FIN).

[13] In Figure 3-6, ELC refers to electricity

Primary resources are modelled as either renewable resources or imported fuels, which feed into electricity generation technologies. Electricity generated from these technologies in a region can be supplied to its end-use sector, exported to other regions or sent to electricity storage systems. CO_2 from fossil fuels are tracked at the resource consumption level.

The following sections describe the various RES components in detail. Only aspects common to all regions are described in the following subsections, with country-wise specifics given in the appendix (see Appendix A).

3.4.3 Electricity demands and load curves

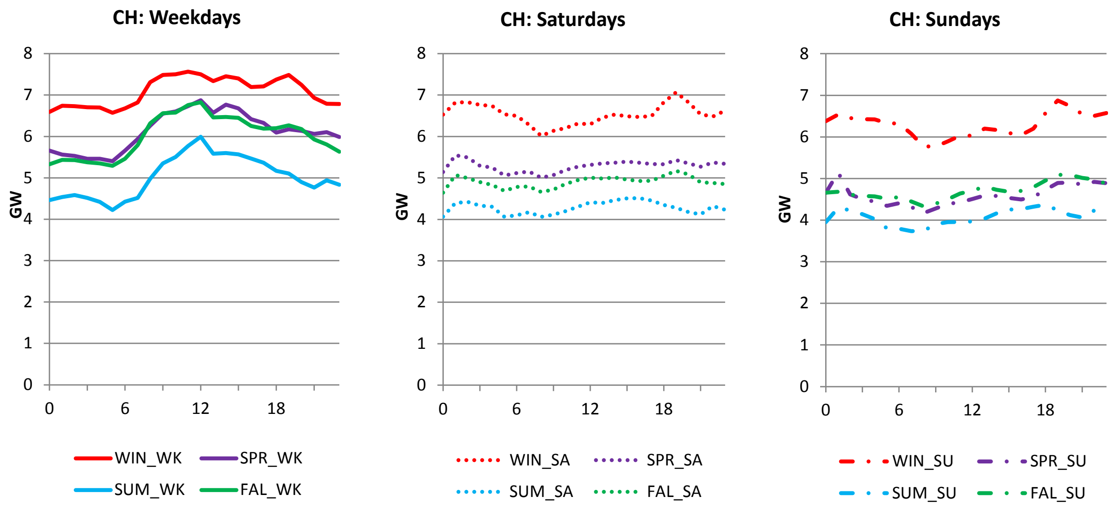
Electricity demand is modelled as an energy service demand (ESDs). The Swiss region in CROSSTEM has five electricity end use sectors *viz.* residential (R), service (S), transport (T), industry (I) and agriculture (A)[14]. The other four regions (Austria, Germany, France and Italy) have one aggregated electricity end use sector each.

Electricity demand is one of the key exogenous inputs to the model. Literature is abundant with projections of different electricity demand trajectories using various modelling frameworks and demand drivers such as population growth, economic development, national and EU policies, technology spill over etc. (Andersson et al., 2011; Densing et al., 2014; European Commission, 2013; PROGNOS AG, 2012). Scenario specific assumptions on future electricity demands are given in Chapter 4 and Chapter 5.

For the intra-annual variations in electricity demand, electricity load curves from the year 2010 (ENTSO-E, 2014) are adopted for all countries for the entire model horizon. For example, Figure 3-7 shows the average/typical hourly electricity demand curves for Switzerland in 2010 for weekdays, Saturdays and Sundays (refer to Appendix A for other countries). However, the assumption of using 2010 load curves for future years does not take into account for instance the increasing electrification in the transport

[14] This was to synchronise the CROSSTEM demands with the end-use sectors in the GENESwIS model for the ELECTRA project (see chapter 4)

sector or space heating applications in future (via electric vehicles, heat pumps), which could significantly alter the shape of the load curves. A sensitivity analysis to highlight the effects of different load curves is presented in Chapter 5.



Source: (ENTSO-E, 2014)

Figure 3-7: Electricity load curve 2010 (Switzerland)

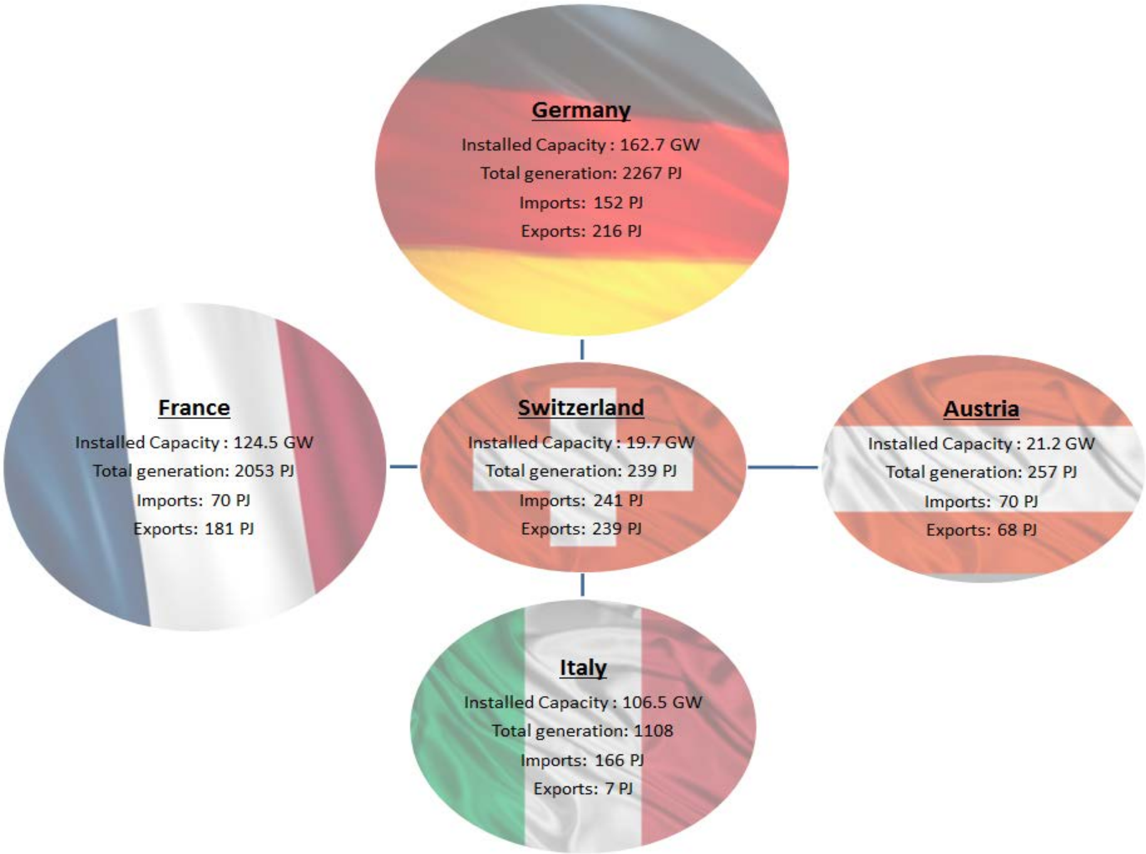
It should be noted that the electricity demand assumptions in CROSSTEM are inelastic, i.e. demand responses and electricity efficiency improvements are not explicitly represented, with demand side measures expected to be captured in the assumed electricity demand growth rate. Although TIMES has the option to analyse price elasticities of demand, it was outside the scope of this thesis. Nevertheless, electricity demand responses were analysed within the scope of the ELECTRA project by coupling part of the CROSSTEM model with a general equilibrium model, and is extensively discussed in Chapter 4.

3.4.4 Electricity generation Technologies

Electricity supply to the end-use sector(s) can be produced with a range of existing and new electricity generation technologies, which are described in the following subsections. Since there is no representation of heat demand in CROSSTEM, combined heat and power (CHP) technologies are not modelled. For model calibration purposes, existing CHP technologies are added to an equivalent fuel-based electricity generation technology. For example, natural gas CHP generation is allocated to gas power plants.

3.4.4.1 Existing technologies

All the existing electricity generation technologies in 2010 from the five countries have been included at an aggregated level by fuel and technology. A list of existing technology categories with their capital stock and technical characteristics for each country is given in Appendix A. The model is calibrated for the base year of 2010 (see Figure 3-8) using OECD & ENTSO-E databases (ENTSO-E, 2014; International Energy Agency, 2015), as well as data from the respective national statistics (Bundesamt für Energie, 2010; Bundesministerium für Land- und Forstwirtschaft Umwelt und Wasserwirtschaft (BMLFUW), 2009; Bundesministerium für Wirtschaft und Energie, 2011; TERNA, 2014).



Source: (International Energy Agency, 2015)

Figure 3-8: Base year (2010) calibration data in CROSSTEM

All the existing technologies have fixed and variable operation and maintenance (O&M) costs, which are assumed to be the same as for the corresponding future technologies (see Table 3-5). Capital costs have been included for certain technologies[15], purely for purposes of coupling with the CGE model, which requires annuities of existing capital stock. Thus capital costs assumptions for new technologies were used for certain existing technologies. However, this assumption does not affect the model solution in the long term because (a) electricity generation from existing technologies is based on their O&M and fuel costs; and (b) when two scenarios are compared, the annuities of the existing stock would balance out. Capacity factors[16] and efficiencies have been calculated for the last decade (2000-2010), at the aggregated technology level, and their statistical averages are applied across the technologies for the future years. The model does not force the existing capacity to be used to its full availability, and power plants can be retired earlier if they are no longer cost effective to operate.

3.4.4.2 Hydro power

Hydro power plants are classified into three categories – dam-, river- and pumped storage hydro. The river hydro is further split into two sub categories (small and large) for countries where data is available (Switzerland and Italy). All hydro plants are assumed to have a lifetime of 80 years, with existing plants having to be retired or refurbished at the end of their lifetime. Refurbishment is assumed to be the replacement/repair of existing equipment (turbine/generator) and/or desilting the reservoir. The cost of refurbishment is assumed to be 35% of the investment cost of a new hydro power plant (Kannan et al., 2011).

Since there are no large variations within daily or weekly outputs of river hydro plants, they have been modelled as seasonal base-load power plants, i.e. output within a season remains stable, subjected to their seasonal availability factors. Monthly river-hydro availability factors of Switzerland and the four neighbouring countries are shown in Figure 3-9, based on which the seasonal availability factors are estimated (Bundesamt für Energie, 2010; E-Control, 2014; ENTSO-E, 2014; Gaeta, 2014; Kannan et al., 2011) (see Appendix A).

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[15] Mainly for capital intensive technologies like hydro, nuclear, solar PV and wind technologies.
[16] Capacity factors are used as availability factors of the existing technologies for the future years.

Dam and pumped hydro plants are modelled as flexible (i.e. dispatchable) electricity generation technologies, subjected to seasonal availability of reservoirs. Similar to river hydro plants, dam hydro plants also have seasonal variations[17], which are represented by seasonal maximum availability factors and are shown in Table 3-3 (Bundesamt für Energie, 2010; E-Control, 2014; ENTSO-E, 2014; TERNA, 2014). A minimum and maximum availability factor has also been implemented at the daily level to prevent the dam hydro plants from running only during weekdays, when the electricity demand and costs are higher than Saturdays and Sundays.

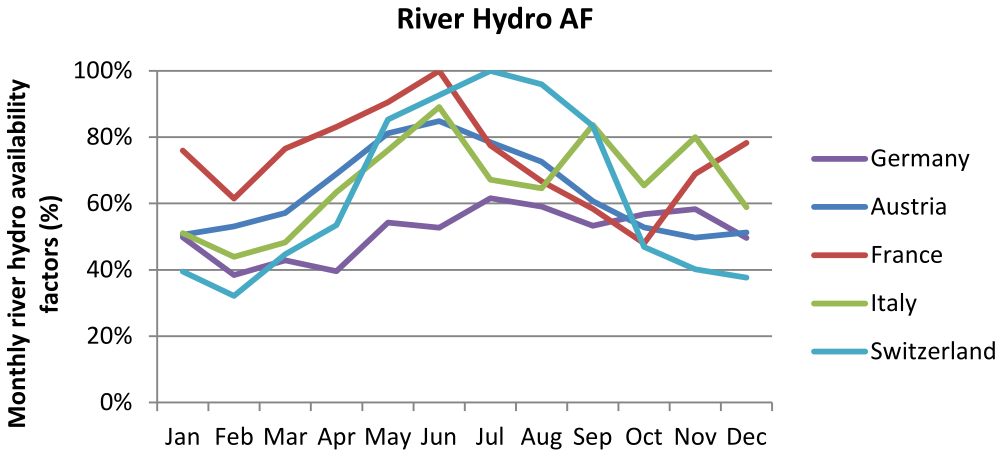


Figure 3-9: Monthly availability factors for river run-off plants

Table 3-3: Seasonal availability factors for dam hydro plants

	Summer	Winter	Fall	Spring
Austria	29%	25%	37%	9%
Switzerland	32%	22%	38%	9%
Germany	28%	23%	23%	26%
France	26%	28%	19%	29%
Italy	31%	21%	23%	25%

The pumped storage system is modelled as an intra-annual storage technology.

[17] Seasonal variations are estimated based on monthly electricity generation and installed capacity.

Electricity can be stored at hourly, daily and seasonal time scales. A storage and conversion loss of 20% is assumed for the pumped hydro plants (Kannan et al., 2011).

3.4.4.3 Nuclear power

Nuclear power plants are characterized as seasonal base-load plants. For Switzerland, all five nuclear plants are modelled individually, whereas for Germany and France, the total capacity is represented at an aggregated level. Figure 3-10 shows the retirement schedule of nuclear plants in the three countries. All the existing plants in Switzerland and France are assumed to have a lifetime of 50 years, whereas plants in Germany are retired by 2023 according to their national nuclear phase-out strategy (World Nuclear Association, 2014b).

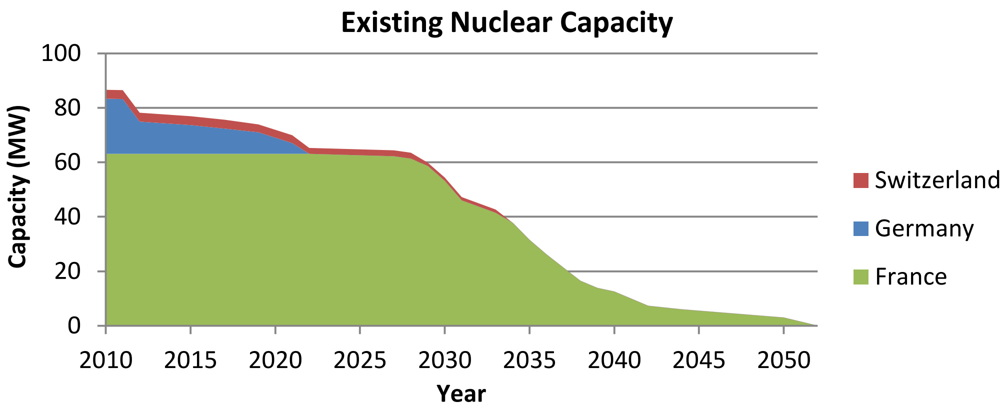


Figure 3-10: Retirement schedule of existing nuclear capacity

All the nuclear plants have an annual availability factor, as well as seasonal availability factors. Seasonal variability of nuclear plants arises mainly due to varying demands between seasons, as well as scheduled maintenance operations carried out during low demand seasons (typically summer). Seasonal (ENTSO-E, 2014) and annual (International Energy Agency, 2015) availability factors are estimated based on historical generation, and are given in Table 3-4.

Uranium for the nuclear power plants is modelled as an imported fuel. The spent fuel from the nuclear reactor is not traced, which implies that there is no cost data associated with spent fuel reprocessing or nuclear waste disposal in the model. However, a federal levy of 0.2 Rappen/kWh for the decommissioning funds *(Stilllegungsfonds für Kernanlagen)* and 0.8 Rappen/kWh for the waste disposal funds *(Entsorgungsfonds für*

Kernkraftwerke) is modelled as a tax on electricity from nuclear plants in Switzerland (Bundesamt für Energie, 2014c; Kannan et al., 2011). The same approach has been adopted for France and Germany as well.

Table 3-4: Nuclear park availability factors

	Germany	Switzerland	France
Annual	85%	93%[18]	81.5%
Summer	76%	68%	69%
Winter	95%	98%	98%
Spring	79%	96%	80%
Fall	91%	84%	79%

3.4.4.4 Thermal power

All large thermal power plants other than nuclear (i.e. gas, coal, oil, and biomass/waste) are modelled as base load power plants. The model also has provisions for a flexible gas power plant to operate as a dispatchable load following plant. These flexible power plants are assumed to have an efficiency penalty to reflect ruptured/part-load operational characteristics.

As mentioned before, since there is no heat demand, CHP technologies are not modelled and electricity generation from the existing CHP generation is allocated to the respective electricity generation technology. Historical average capacity factors are applied as the availability factors (of existing technologies) for the future years.

An annual growth constraint of 1% is applied on the total installed capacity of coal and lignite[19] fired power plant technology in all countries except Switzerland[20], based on the

[18] Average of the five nuclear plants in the model. See Appendix A for individual plant availability factors.
[19] Available for Germany only.
[20] Switzerland does not consider coal/lignite based technologies as an alternative supply option

average annual coal power capacity expansion in Germany during the last 15 years[21] (2000-2014) (Global Energy Observatory, 2014). This is to prevent unrealistically high investments in coal for future years given the current European policies in place..

3.4.4.5 Renewables

New renewable technologies (non-hydro) such as solar photovoltaic (PV) and wind (onshore and offshore) are characterized by country specific hourly availability factors. All other renewable technologies such as geothermal, biomass and tidal plants are modelled as seasonal base-load plants. Efficiency is assumed to be 100% for all the renewable technologies (except biomass), but capacity and availability constraints are applied to reflect resource and technical potentials (see Table 3-6). The following subsections describe the renewable technologies in detail.

Solar Photovoltaic (PV)

Monthly and hourly solar irradiations were analysed for selected locations from each country, for a tilt angle of 35 degrees from the azimuth (JRC, 2013). The hourly and monthly availabilities are normalized to annual capacity factors for solar PV, and the hourly capacity factors are implemented as hourly availability factors. An example for Germany is shown in Figure 3-11 (see Appendix A for other locations).

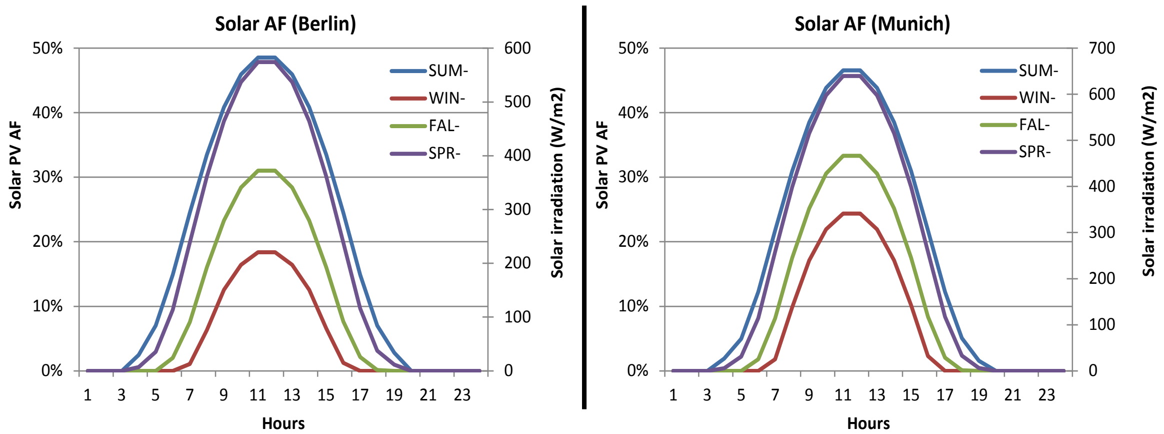


Figure 3-11: Hourly solar irradiation and solar PV availability factors (Germany)

[21] Coal expansion in Germany over last 15 years is 19% (annual 1.2%), Lignite 23% (annual 1.4%)

Wind Energy

Hourly wind based electricity generation profiles from all the countries, for the years 2010-2013 were used to estimate the aggregated hourly capacity factors, and were implemented as hourly availability factors in the model. An example of the wind profile for Austria (Austrian Power Grid, 2014) is given in Figure 3-12. It can be seen that the wind based electricity generation is usually higher during the night time than during the day. One can also notice seasonal variability, with the availabilities generally lowest during the summer. It is important to note that the wind turbines are not forced to follow this wind profile. Instead, the maximum output from wind turbines is restricted by the availability factor. Thus, the model could curtail generation from wind turbines in order to balance electricity supply and demand. Alternative scenarios with no wind or solar curtailment are presented in Chapter 5.

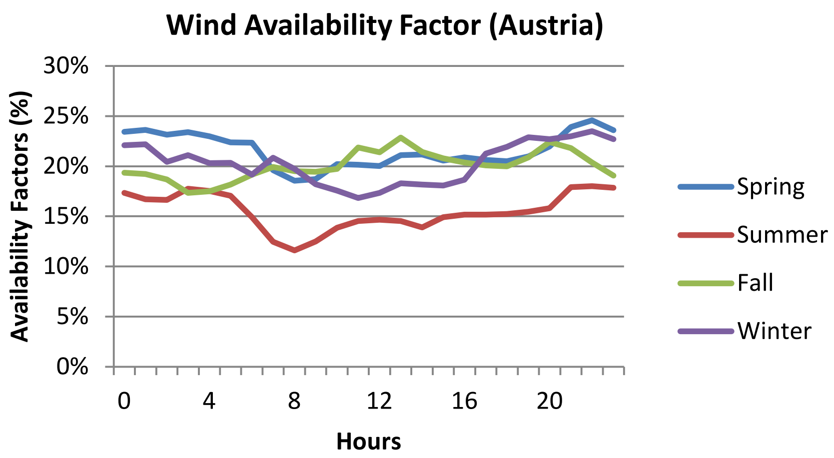


Figure 3-12: Availability factors for wind turbines (Austria)

Other renewable technologies

Geothermal and tidal plants are characterized as seasonal base-load plants (variations are only allowed on a seasonal level). Biomass, wood and waste incinerators are characterized as annual base-load plants. Although the existing plants of the latter technologies are mainly CHP plants, they were modelled as electricity plants (since CROSSTEM does not cover the heat sector). Since total installed capacity of CHP is relatively low (for example in Switzerland, CHP accounts for less than 3% of the total electricity generation capacity), this assumption is not significant.

3.4.4.6 Transmission and Distribution (T&D) Network

CROSSTEM is a spatially aggregated model and therefore the interconnectors between the regions and transmission and distribution networks within each region are not explicitly modelled, i.e. the countries are modelled as copper plate regions. However, to account for the T&D costs, an ad-hoc T&D grid is included with a simplified cost function correlating costs to the size of the country, as shown in Figure 3-13. Investment costs per km of transmission line were taken from (Odenberger & Unger, 2011), while their O&M costs were based on Swiss Grid network usage charges (Swiss Grid, 2008). In this manner, larger countries such as France and Germany would have higher costs of expanding the grid compared to smaller countries like Switzerland or Austria.

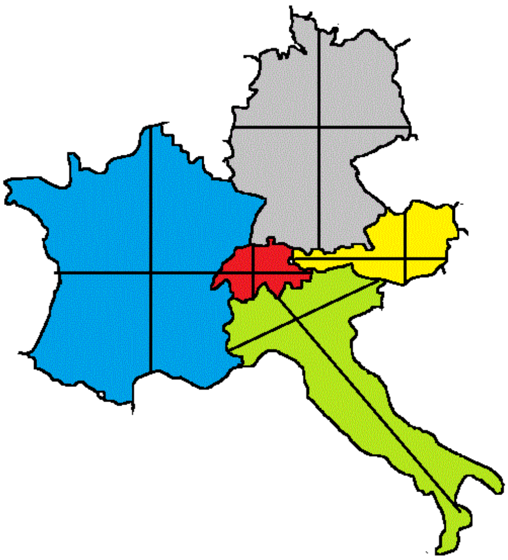


Figure 3-13: T&D grid CROSSTEM

Transmission and distribution losses of 5 – 7% are assumed based on historical values of each country.

3.4.4.7 New and future technologies

A range of new and future technologies have been included to supplement the existing technologies. All existing technology categories are included for future technologies. In addition, some newer technologies such as Carbon Capture and Storage (CCS) and Concentrated Solar Power (solar CSP) are also introduced. The techno-economic characteristics of the new technologies are given in Table 3-5. The technologies also have a learning curve with vintages, reflecting capital cost reduction and efficiency improvements over time. Figure 3-14 shows the capital cost reduction for selected renewable technologies. For large scale power plants, construction times are included to factor in lead times and interest costs during construction. Similarly, decommissioning time and costs are also incorporated. Most of the techno-economic data for new technologies are adopted from estimates by the PSI Technology Assessment group (Paul Scherrer Institute, 2010), with other sources (International Renewable Energy Agency (IRENA), 2012; Lako, 2010; Resch et al., 2006; Schröder et al., 2013) used for updates and cost comparisons.

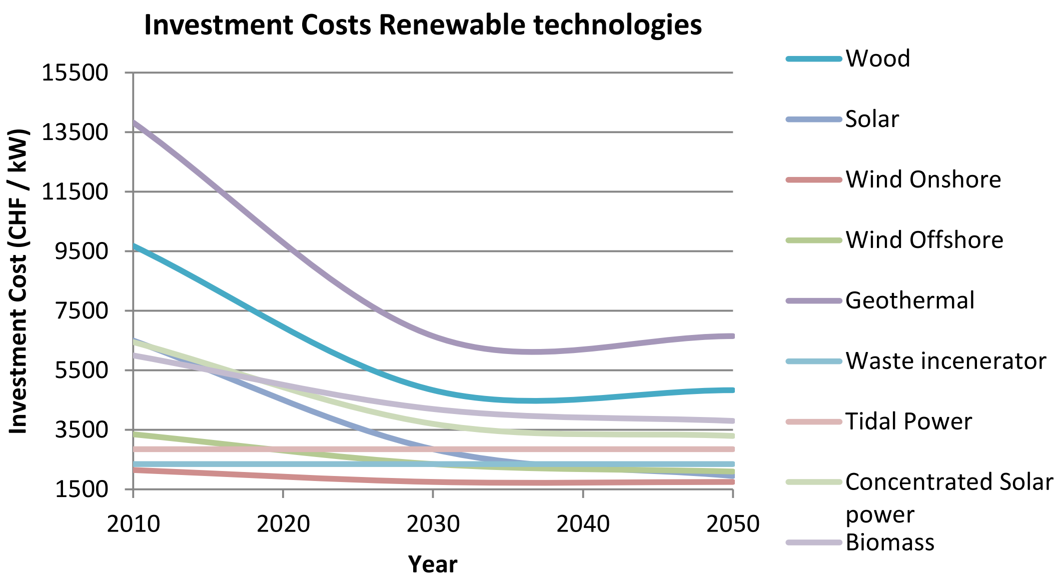


Figure 3-14: Investment costs of renewable technologies

Non fossil fuels, including electricity imported from fringe countries[22] are assumed to be carbon free. Carbon capture and storage (CCS) technologies have a capture efficiency of 90%, and are assumed to be available from 2030 onwards. A capacity reserve margin of 30% is assumed throughout the model horizon and all technologies with the exception of wind and solar technologies contribute to the reserve calculation.

[22] Fringe countries are the countries surrounding the five regions in CROSSTEM. They are modeled as one external region, with the imports and exports between a CROSSTEM region and fringe region being limited to historical upper limits on an annual basis.

Table 3-5: Technical characteristics and cost of new technologies

Technology Description	Vintage Year	Life time (year)	Efficiency (%)	Availability Factor[+] (%)	Capital Cost (CHF/kW)	FOM Cost (CHF/kW/year)	VOM Cost (CHF/GJ)	Lead time (year)
Hydro (River)	2015	80	80%	63%	6'560	18.2	1.67	3
Hydro (Dam)	2015	80	80%	27%	10'000	9.7	1.84	3
	2030	80	80%	27%	8'000	9.7	1.84	3
Nuclear[@] : Gen2 (LWR)	2010	50	32%	80%	4'250	22.5	3.25	6
Gen3 (EPR)	2030	60	35%	80%	4'250	11.6	1.92	6
Gen4 (FBR)	2050	40	40%	80%	4'750	55.1	0.18	6
Coal: SCPC*	2010	30	43%	80%	2'350	40.3	0.69	3
	2050	35	54%	87%	2'050	45.1	0.79	3
Coal: SCPC with CCS	2030	35	43%	87%	3'200	69.3	0.92	3
	2050	35	49%	87%	2'900	69.3	0.92	3
Lignite[$] : SCPC	2010	40	40%	86%	2'450	52.0	0.69	3
	2050	40	49%	86%	2'137	58.2	0.79	3
Lignite[$] : SCPC with CCS	2030	40	33%	86%	4'480	95.0	0.92	3
	2050	40	41%	86%	4'060	95.0	0.92	3

Natural Gas: GTCC# Base load	2010	25	58%	82%	1'150	7.8	6.72	3
	2050	25	65%	82%	1'050	7.8	6.72	3
Natural Gas: GTCC with CCS	2030	25	56%	82%	1'700	15.6	13.44	3
	2050	25	61%	82%	1'500	15.6	13.44	3
Solar: PV	2010	40	100%	11%	6'500	5	1	0
	2030	40	100%	11%	2'850	5	1	0
	2050	35	100%	11%	1'950	5	1	0
Wind: Onshore	2010	20	100%	14%	2'150	44	14	0
	2030	20	100%	14%	1'750	28	9	0
	2050	20	100%	14%	1'750	28	9	0
Wind: Offshoreβ	2010	20	100%	44%	3'350	87	9	2
	2030	20	100%	44%	2'350	58	6	2
	2050	30	100%	48%	2'100	22	14	2
Geothermal	2020	30	100%	80%	13'825	134	12	3
	2030	30	100%	80%	6'650	87	29	3
Waste Incinerator	2020	30	15%	15%	2'350	40	1	3
Pump hydro	2010	80	80%	27%	7'000	10	2	3

Tidal Power plant ^	2010	25	100%	30%	2'850	49	-	3
Solar: CSP&	2010	25	100%	33%	6'449	65	2	3
	2050	25	100%	33%	3'295	65	2	3
Interconnector**	2010	50	100%	90%	950	95	0.4	0
Seasonal Storage^^	2010	30	50%	50%	1'200	36	-	3
	2050	30	60%	50%	600	18	-	3
Battery$$	2010	20	70%	50%	3'120	94	-	3
	2030	20	80%	50%	2'592	78	-	3
	2050	20	85%	50%	1'800	54	-	3

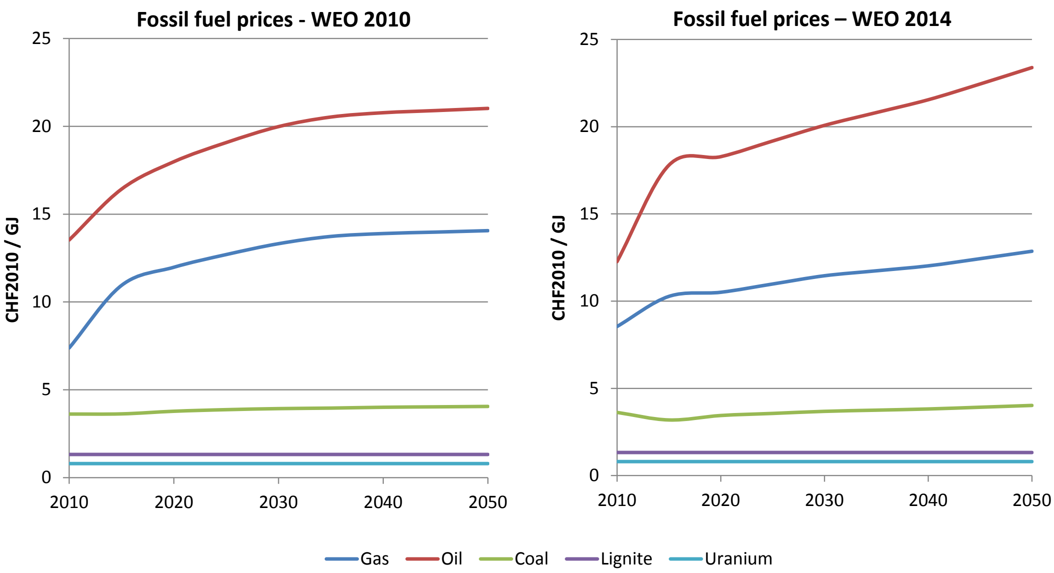
+ All renewable availability factors given in this table are for Switzerland. AF's varies across different regions, especially those for renewable technologies, and is detailed in the appendix.
@ LWR – Light Water Reactor; EPR – European Pressurised Reactor; FBR – Fast Breeder Reactor
* SCPC – Supercritical pulverized coal
$ Lignite fired power plants are only available in Germany
# GTCC – Gas turbine combined cycle: The data given is for base-load plants. For flexible gas plants (merit order), the same cost numbers have been used, but a 20% penalty is applied to efficiency and availability factor to account for interrupted operation.
β Technology only Available for Germany, France, and Italy.
& Technology only available for Italy.
^ Technology only available in Italy, France
** Interconnector investment and FOM costs are given in CHF/km/kW. These numbers are subsequently multiplied with interconnector distances between two regions.
^^ Techno-economic patarameters for Compressed Air Energy Storage (CAES) used
$$ Flow battery storage for wind turbines and large scale solar PV generation

Two new categories of storage technologies are also included in addition to pumped storage systems. Battery storage allows for hourly storage, while a seasonal storage technology allows for storage on a weekly and seasonal level. Techno-economic characteristics of the storage technologies were adopted from (Bundesamt für Energie, 2013).

3.4.5 Energy Resources

Energy resources are modelled in three broad categories *viz.* imports (which include all fossil fuels as well as electricity imports), exports (only electricity to neighbouring regions via interconnectors) and renewables (all renewables resources, including hydro). Energy resources are characterized with resource availability and cost. Cost of uranium fuel rods for nuclear power plants are adopted from (Paul Scherrer Institute, 2010).

There are no specific resource constraints for the fossil fuels. The international energy prices for the ELECTRA project scenario analysis described in chapter 4 are adopted from the world energy outlook 2010 (International Energy Agency, 2010) (Figure 3-15a). In Chapter 5 and 6, fuel prices are updated to the latest international fuel price assumptions from world energy outlook 2014 (International Energy Agency, 2014) (Figure 3-15b).



(a) (b)

Figure 3-15: International fuel prices 2010 vs 2014

Renewable resource potentials implemented in CROSSTEM are based on various national and EU-wide studies (Akademien der Wissenschaften Schweiz, 2012; Beurskens L.W.M. et al., 2011; Bundesministerium für Land- und Forstwirtschaft Umwelt und Wasserwirtschaft (BMLFUW), 2009; Chamorro et al., 2014; Ess et al., 2012; European Commission, 2013; Kannan et al., 2011; Lako, 2010; Lanati & Gelmini, 2011; Nitsch et al., 2012; Resch et al., 2006; Réseau de transport d'électricité, 2012). Table 3-6 shows a summary of the technical renewable energy potentials used for the five countries in the model. The potentials are linearly interpolated from the actual deployment in 2010 to the 2050 values. There are high uncertainties regarding the renewable resource potentials, and therefore they constitute a potential subject for sensitivity analysis. For example, enabling an early uptake of the full renewable potential would be desirable for a stringent climate target scenario.

Table 3-6: Assumptions on technical renewable energy potentials

Energy Resource	Technical potentials (2050) (PJ_{elc})				
	AT	CH	DE	FR	IT
Waste & Biogas	3	8.1	21	16	18
Biomass (Wood)	23	13	191	65	76
Solar PV	11	36	230	159	288
Solar CSP	-	-	-	-	29
Wind (Onshore)	25	14	475	234.8	64
Wind (Offshore)	-	-	461	332.2	129
Geothermal	1	16	69	5	57
Hydro (Reservoir)	31	75	3.6	131	50
Hydro (run of river)	117	58	86	117	145
Tidal Power	-	-	-	5.2	0.03

3.4.6 Electricity trade

As a multi-region model, CROSSTEM has the option to trade electricity endogenously between the five countries based on their marginal cost of electricity generation. In addition, the model has the option to import and export electricity with the external fringe region based on exogenous electricity price assumptions. Import/Export prices with the fringe region have been adopted from the ADAM project for Chapter 4 (Frauenhofer, 2010; Kannan et al., 2012), and from the EUSTEM[23] model for Chapter 5. Figure 3-16 shows the hourly exogenous electricity import/export prices of fringe regions in the year 2050 used in Chapter 4.

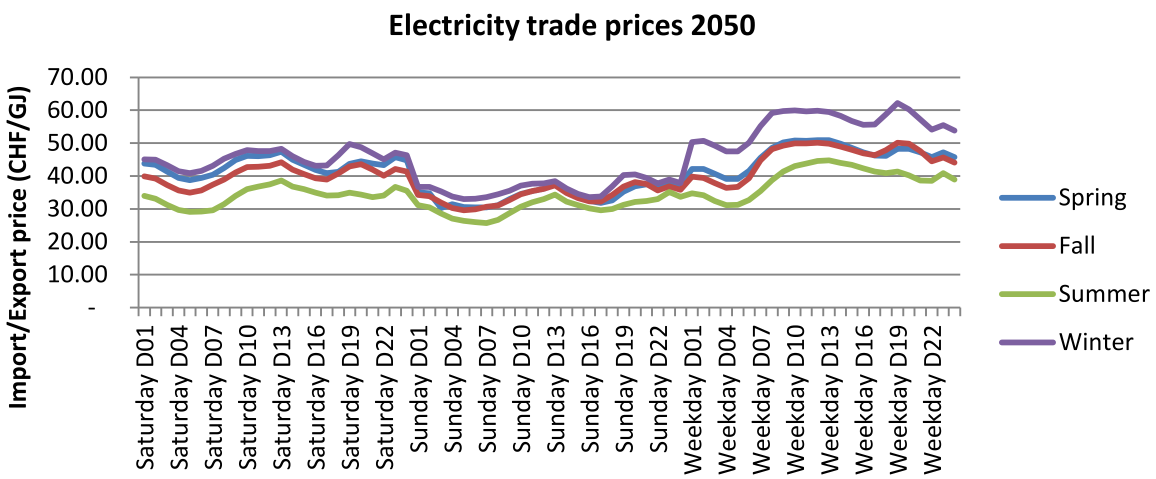


Figure 3-16: Electricity trade prices to and from fringe regions in 2050

The model has the option to invest on new interconnector capacities. CROSSTEM has full freedom with respect to the timing of the imports and exports at intra-annual time slice levels. In Chapter 4, constraints are applied at annual levels to keep historical trends in electricity trade. For example, Italy and Austria are traditionally net importers of electricity while France, Switzerland and Germany are net exporters. For the scenarios analysed in Chapter 4, these boundary conditions on trade are not allowed to change, i.e. net exporting countries cannot become net importers in the future and vice versa[24]. This constraint is relaxed in the scenario analysis presented in Chapter 5. To avoid excessive import to circumvent stringent low carbon scenarios, net trade with the external fringe region is also bounded to the historical maximums. The CROSSTEM

[23] The European Swiss TIMES Electricity Model (EUSTEM) model is discussed in detail in Chapter 6
[24] The trade constraints are introduced to prevent the model making investments in just one country and all other countries importing from that country.

countries can only trade with their adjacent neighbours, as shown in the matrix below (Table 3-7).

Table 3-7: Electricity trade matrix

Trade	CH	AT	FR	DE	IT	OT*
CH						
AT						
FR						
DE						
IT						
OT*						

* Denoting Fringe (other) region

Interconnector available

Interconnector unavailable

As mentioned in section 3.4.4.6, CROSSTEM is a spatially aggregated model; therefore T&D networks are not modelled explicitly. For the analysis in chapter 4, universal interconnector capacity costs were applied for all regions. This assumption however does not take into account the additional transmission network expansions required within each region to get the electricity to the borders. This assumption was updated for the analysis in chapter 5. To account for interconnectors between big and small countries, interconnector costs are implemented based on mid-point average distances between national nodes as shown in Figure 3-17. For example, an interconnector between Italy and Switzerland is 35% more expensive than an interconnector between Switzerland and Austria, thereby having some representation of transmission distances. The interconnectors are assumed to have no energy loss, i.e. the losses are assumed to be embedded in T&D losses. An annual availability of 90% is included to account for annual maintenance (own assumption). Existing interconnector capacities are calibrated based on NTC values from ENTSO-E (ENTSO-E, 2015).

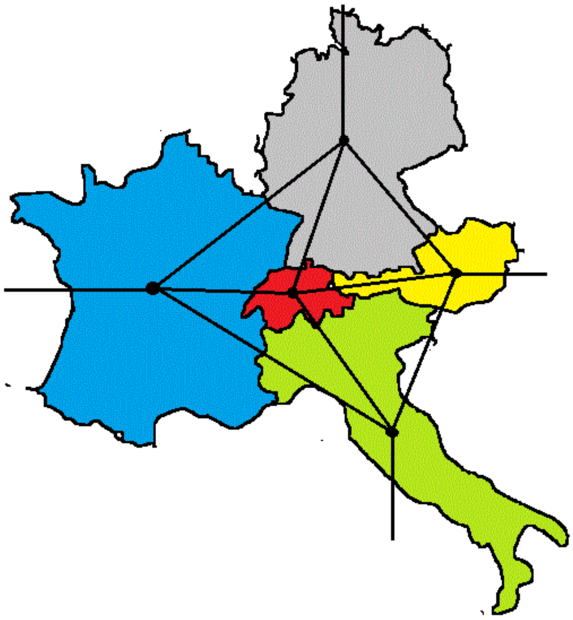


Figure 3-17: Interconnector distances in CROSSTEM

3.4.7 Carbon dioxide (CO2) emissions

Carbon dioxide (CO_2) emissions from fossil fuels are traced at the resource consumption level, with CO_2 emission factors assigned to each fuel type as given in Table 3-8. Non fossil fuels, including imported electricity from fringe countries are assumed to be carbon-free. A CO_2 emissions tax is applied to all scenarios described in this thesis based on the Emission Trading Scheme (ETS) price assumptions used in the Swiss energy perspectives (PROGNOS AG, 2012) which in turn was taken from the "New Energy Policy" scenario of the IEA World Energy Outlook 2010. The CO_2 tax ranges from 15 CHF/t CO_2 in 2010 to 57 CHF/t CO_2 by 2050.

Table 3-8: CO_2 emission factors

Energy commodity	CO_2 emission (t/TJ)
Lignite	116
Coal	91
Oil	78
Gas	56

3.4.8 CCS storage potentials

Carbon Capture and Storage (CCS) technologies are assumed to be available from 2030. The market potential of CCS technologies is limited by the CO_2 storage potentials. The storage potentials for Switzerland is taken from (Diamond, 2010), and for the remaining countries from various EU studies (EU Geocapacity, 2009; Simoes et al., 2013). Three different levels of storage potentials have been considered for the various scenarios analysed and are shown in Figure 3-18.

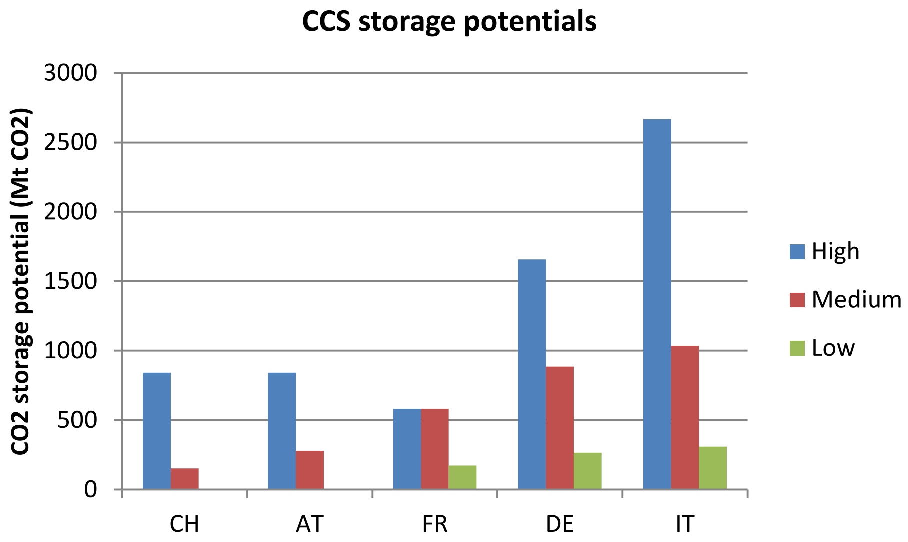


Figure 3-18: CCS storage potentials

The high CO_2 storage potential incorporates all the CO_2 storage options like hydrocarbon fields, onshore and offshore aquifers etc. This high storage potential is used for the analysis in Chapter 4. The medium CO_2 storage potentials are limited to hydrocarbon fields, and the low storage potentials only account for 30% of the medium storage capacities for an even more conservative estimate[25] (see Figure 3-18). The medium storage potentials are used in Chapter 5. The low storage potentials are used for scenario analysis in Chapter 6, where the scope of the model is expanded from CROSSTEM to EUSTEM.

[25] For Switzerland and Austria, the low CCS potential is assumed to be zero.

4 APPLICATIONS OF THE CROSSTEM FRAMEWORK

This chapter discusses the application of the CROSSTEM model, in the context of the ELECTRA project. The ELECTRA project: “Electricity markets and trade in Switzerland and its neighbouring countries: Building a coupled techno-economic modelling framework”, was funded by the Research Program Energy-Economic-Society of the Swiss Federal Office of Energy (SFOE). The project was a collaboration between three institutions namely Econability (S. Maire, F. Vöhringer), the Energy Economics group of Paul Scherrer Institute (R. Pattupara, K. Ramachandran, H. Turton), and the Research Group on the Economics and Management of the Environment (REME) of EPFL (Prof. P. Thalmann, M. Vielle) (Voehringer et al., 2011). The main aim of the 3½ year project was to create a novel coupled modelling framework for the analysis of energy policies in Switzerland. PSI developed the bottom-up models for the coupled framework, while the coupling of the models was undertaken by Ms. Sophie Maire.

The chapter begins with an overview of the project and motivation for developing a coupled framework. The models involved in the coupling procedure and a snapshot of the coupling methodology is then described. The section concludes with results from the coupled framework as well as from selected scenarios of the CROSSTEM model. Excerpts from the project report (Maire, Pattupara et al., 2015) are used extensively in this chapter.

4.1 Introduction

The original aim of the ELECTRA project was to create an integrated top down – bottom up framework that would enable the analysis of Swiss energy and climate policy impacts on the energy sector, while simultaneously accounting for effects from international policies and electricity trade. In order to achieve this, multiple models were developed and linked to each other in an iterative process. A dynamic bottom-up model (CROSSTEM and a version representing only Switzerland, called CROSSTEM-CH) would provide a detailed representation of the Swiss electricity system at a high time resolution. Dynamic computable general equilibrium (CGE) models of the Swiss (GENESwIS, (Vöhringer, 2012)) and global (GEMINI-E3, (Bernard & Vielle, 2009)) economies in turn would deliver a microeconomic representation of elastic electricity demand by economic sectors as well as the rest of the economy including price-driven links with the electricity sector.

Coupling models that differ in their approaches (such as bottom-up vs top-down models) provides insights that cannot be obtained by the models on their own. For example, while the CROSSTEM model describes the electricity sector in high technological detail and can be used for analysing the evolution of the Swiss electricity system under various energy and climate policies, it cannot capture the effects on the rest of the economy, electricity demand variations due to price effects and substitutions with other energy carriers (such as in the heating or transport sectors) and so on. GENESwIS on the other hand is a fully dynamic model of the Swiss economy, with a focus on energy policy and greenhouse gas emission trading, but has a highly simplified representation of the electricity sector, thereby minimising its capability to analyse electricity sector specific policies (Vöhringer, 2012). By coupling these two models, it is possible to enhance the representation of the electricity sector within the general equilibrium model. In this way, technological details are taken into account in the general equilibrium model, which allows the analysis of specific policies surrounding the electricity sector of Switzerland (such as the nuclear moratorium, increased renewable based electricity generation, electricity import/export markets). Concurrently, it is also possible to integrate general equilibrium effects into the partial equilibrium model (CROSSTEM) via electricity demand variations, fuel price and technology cost indicators at a national level (via the GENESwIS model) and at a European and international level (via the GEMINI-E3 model) (Voehringer et al., 2011).

Over the course of the project, the coupled framework ELECTRA-CH, consisting of the CROSSTEM-CH and GENESwIS, was completed, while important steps were taken towards the integration of CROSSTEM with the GEMINI-E3 and GENESwIS model for the full ELECTRA framework, which was however not completed. The next section will therefore briefly describe the methodology and results of the ELECTRA-CH framework only.

4.2 ELECTRA-CH framework

Two models were used to develop ELECTRA-CH, the CROSSTEM-CH model and the GENESwIS model. This section will start with a brief description of both models, followed by the coupling procedure. Detailed explanations can be found in the ELECTRA project report (Maire, Pattupara et al., 2015).

4.2.1 Methodology

4.2.1.1 CROSSTEM-CH

As mentioned before, the CROSSTEM model was developed within the ELECTRA project framework. CROSSTEM can also be run in an individual country mode for Switzerland, by using exogenously defined electricity interconnectors to simulate the international electricity exchange with Austria (AT), Germany (DE), France (FR) and Italy (IT) (see Figure 4-1). This single region model is referred to as CROSSTEM-CH and is analogous to the STEM-E model, which was developed at PSI by R. Kannan and H. Turton (Kannan et al., 2011).

CROSSTEM-CH varies from STEM-E in certain aspects regarding model structure as well as input data. These changes were necessary for the bottom-up model to be aligned with the top-down GENESwIS model for coupling. Notable differences in CROSSTEM-CH over STEM-E include:

- Changes to the model horizon – STEM-E had a time horizon of 100 years (2000 – 2100) split into 14 unequal time periods. This was changed in CROSSTEM (and thereby in CROSSTEM-CH) to 60 years (2010 – 2070), split into 14 time periods, each time step representing five-years (see section 3.4.1.2).

- Updates to technology data – Updates were made to the technology database. For example, new storage technologies such as hourly (battery) and seasonal (Compressed air energy storage) storage systems are introduced in CROSSTEM, as existing pumped hydro storages were foreseen to be inadequate to integrate a high share of intermittent renewable technologies.
- Updates to renewable resource potentials (Akademien der Wissenschaften Schweiz, 2012) in Switzerland, and changes in fossil fuel prices (International Energy Agency, 2010).
- Base year calibration – STEM-E had the year 2000 as the base year, with some near term calibration till 2010. For CROSSTEM (and CROSSTEM-CH) the base year is moved to 2010 as the energy data for 2010 was available. However, data from 2000 – 2010 is still used to reflect historical variations in technical efficiencies and availability factors of existing technologies.
- Modification of base year annuities – To enable coupling between the models, a greater harmonization was required between the electricity price in GENESwIS and electricity generation costs obtained from CROSSTEM-CH. Since GENESwIS is calibrated on the Swiss Input-Output Table (IOT) (Nathani et al., 2011), it became important that average and marginal costs of electricity from CROSSTEM-CH reflected the IOT prices for the calibration year 2010. In order to achieve this, ad-hoc capital costs for existing technologies were introduced in CROSSTEM-CH.

CROSSTEM-CH is a stripped down version of CROSSTEM, and therefore it has all the characteristics of CROSSTEM already described in detail in chapter 3. The main difference between CROSSTEM-CH and CROSSTEM lies in the formulation of electricity trade with the neighbouring countries. In the former, electricity import/export prices and market share of electricity trades with the neighbouring countries are defined *exogenously* based on a set of assumptions whereas in the latter they become *endogenous* variables. In CROSSTEM-CH, the hourly electricity import/export prices were calculated by applying cost coefficients (multipliers) obtained from European electricity spot market data to an annual electricity trade price. The electricity trade prices were based on annual electricity supply costs from the ADAM [26] project (Frauenhofer, 2010). Prices were distinguished between countries by using the electricity demand profiles of each region. These price coefficients aligned electricity prices with the capacity demand of the neighbouring countries. A detailed methodology is explained in (Kannan et al., 2011). It should be noted that import prices adopted from the ADAM model were for a stringent climate scenario, resulting in high import prices.

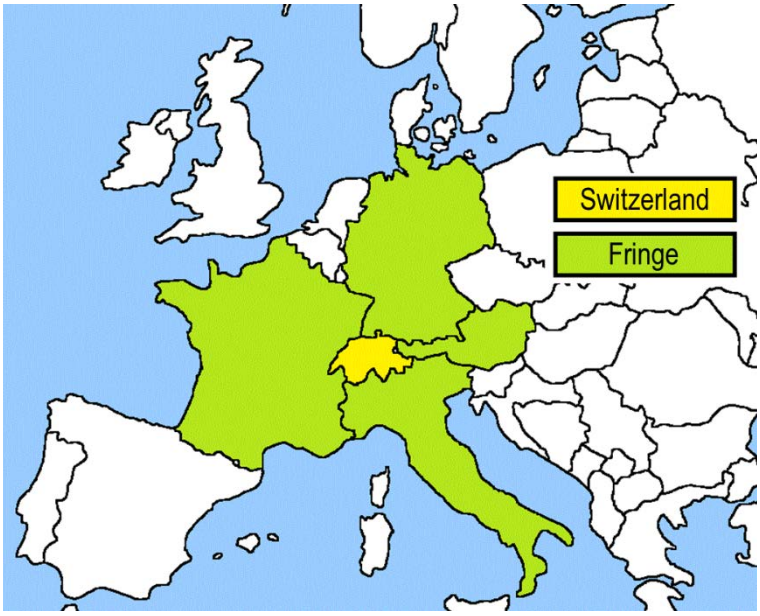


Figure 4-1: Regions in the CROSSTEM-CH model

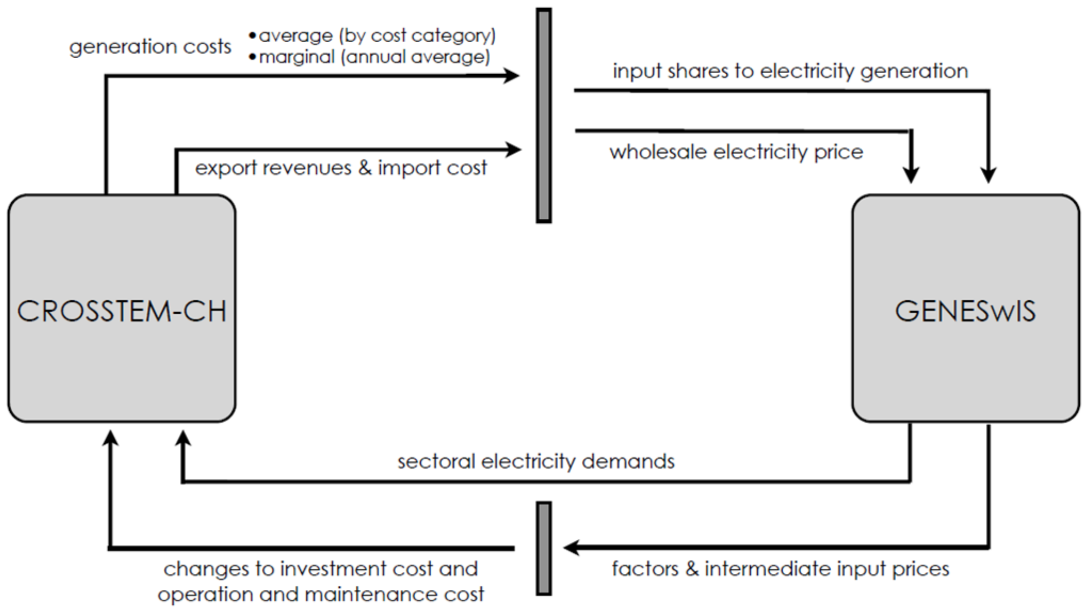
4.2.1.2 GENESwIS

GENESwIS is a multi-sectoral dynamic CGE model of the Swiss economy, designed to analyse energy policies and greenhouse gas emission trading. The model was developed by Dr. Frank Vöhringer from Econability, and updated by Ms. Sophie Maire for the ELECTRA project. Details of the modelling framework can be found under (Maire & Vöhringer, 2014; Voehringer et al., 2011) and in the ELECTRA project report (Maire et al., 2015).

[26] ADAM – Adaptation and Mitigation strategies supporting European climate policy: A European project to evaluate European mitigation policies to reach 2020 goals.

4.2.1.3 The coupled ELECTRA-CH framework

The ELECTRA-CH framework couples the CROSSTEM-CH and GENESwIS models in an iterative process. Figure 4-2 illustrates the information exchange between the two models that takes place at each iteration. The sum total of the electricity production costs, export revenues and import costs is converted into the wholesale electricity price and sent to the CGE model, where it serves as an input to the electricity generation cost function. The generation cost includes average cost (obtained from the total system cost) as well as an annualised marginal cost. The electricity generation mix from CROSSTEM-CH is also sent to the GENESwIS model to obtain input shares for commodities in the electricity generation cost function of the CGE.



Source: (Maire et al., 2014)

Figure 4-2: Information exchange between the two component models

On the other hand, sectoral electricity demands and certain cost factors are sent from the CGE model to the bottom-up model. GENESwIS differentiates the electricity demand into five sectors namely; Agriculture, Industry, Residential, Service and Transport, which matches the end-use sectors in CROSSTEM-CH (see section 3.4.3 in chapter 3). In order to remain consistent, technology price feedbacks are also sent from the CGE model to CROSSTEM-CH. These price-variation coefficients are created based on the weighted shares of different sectors such as labour, metals, cement, transport etc. in

GENESwIS, which are sent to the CROSSTEM-CH model to modify the investment and O&M costs of different technologies[27] in the bottom-up model (Maire et al., 2014).

The sequence shown in Figure 4-2 is iterated, until the vector quantities of the total electricity demand each year converges. Both models are calibrated and harmonized to the Prognos “Weiter Wie Bisher” (WWB) electricity demands, which serves as the baseline scenario. Detailed methodology of the coupling process can be found in the project report.

4.2.2 Applications of the ELECTRA-CH framework

In this section, three illustrative scenarios are described to highlight the functioning of the new coupled framework. The section starts with a description of the scenarios, followed by results and some general conclusions.

4.2.2.1 Scenarios

	Baseline (WWB)	TAX	NoGAS
Market instruments (GENESwIS)	ETS	Same as baseline	Same as baseline
	CO_2 tax on heating fuels 36CHF/t(2010) 72CHF/t(2020-50)	CO_2 tax on heating fuels 72CHF/t (2020) 200CHF/t (2050)	Same as TAX
		CO_2 tax on transport fuels 50CHF/t (2035) 200CHF/t (2050)	Same as TAX
		Electricity tax 10%(2020) 50%(2050)	Same as TAX
Regulation (CROSSTEM)	No net import (yearly average)	Same as baseline	Net import (same total energy [PJ] as imported gas)
			No gas power plants

Source: ELECTRA project report

Figure 4-3: ELECTRA domestic scenarios - comparison of policy instruments

[27] Electricity generation technologies are classified into four main groups: Hydro, Thermal, Solar PV and Other renewables. Price coefficients are exchanged for these technology groups.

Three scenarios were analysed for the ELECTRA project: a baseline scenario (WWB), a scenario with market instruments applied solely on the CGE model (*TAX*), and a scenario with technological restrictions applied solely on the bottom-up model (*NoGAS*). The scenarios are described in the following subsections, and Figure 4-3 depicts the key policy instruments applied in each scenario, also showing in which model the policy instruments are applied.

4.2.2.1.1 Baseline (*Baseline*) scenario

The baseline scenario is based on the business as usual (*WWB*) scenario of the Swiss energy strategy 2050 (PROGNOS AG, 2012). The framework is calibrated to the electricity demands from WWB scenario, while including current policies such as:

- European Emission Trading Scheme (for the ETS sectors in GENESwIS, for CO_2 prices in CROSSTEM-CH). The CO_2 permit prices are taken from the Swiss Energy Strategy 2050 WWB projections (PROGNOS AG, 2012).
- A CO_2 tax on heating fuels for non-ETS sectors (GENESwIS). The Tax values range from 36 CHF/t CO_2 in 2010 to 60 CHF/t in 2015, and 72 CHF/t from 2020 to 2050 and beyond.
- A subsidy program on energy refurbishment of buildings (GENESwIS).
- Annual electricity self-sufficiency constraint (CROSSTEM-CH). Switzerland is assumed to be neither a net importer nor exporter of electricity over the year, but seasonal and daily imports/exports are enabled.
- Nuclear phase-out in Switzerland (CROSSTEM-CH). Nuclear power plants in Switzerland are assumed to be retired after their 50 year life time, with the last plant going off-grid by 2034. This assumption is valid for all three scenarios.

4.2.2.1.2 Tax instruments (*TAX*) scenario

This scenario applies additional tax measures solely on GENESwIS, while boundary conditions in CROSSTEM-CH remain unchanged. The additional tax policy relevant for the electricity system is as follows:

- An additional tax is levied on the electricity consumption in GENESwIS. An electricity tax of 10% is introduced in 2020, increasing linearly to 50% by 2050.

4.2.2.1.3 No-gas (*NoGAS*) scenario

In this scenario, an investment in new gas plants for electricity production is restricted in the CROSSTEM-CH model, while boundary conditions in GENESwIS remain the same as for the *TAX* scenario.

- No new investment in gas-based electricity generation is allowed in Switzerland.
- Relaxation of self-sufficiency constraint. Due to the absence of gas-based electricity, domestic renewable based generation is insufficient to supply the WWB demand. Hence, Switzerland is allowed to be a net importer of electricity. The quantity of net electricity imports is limited to the quantity of gas imported (in PJ) for gas-fired power plants in the *TAX* scenario (see Figure B7 in Appendix B). The rationale behind this simplistic assumption is to keep the same level of energy security, despite the fact that electricity imports and natural gas imports do not imply the same level of security risks.

In this scenario, the relaxation of the self-sufficiency constraint was necessary to obtain convergence. Scenarios with more restrictive boundary conditions such as limiting imports or with different electricity import prices were not solved by the coupler.

4.2.2.2 Results

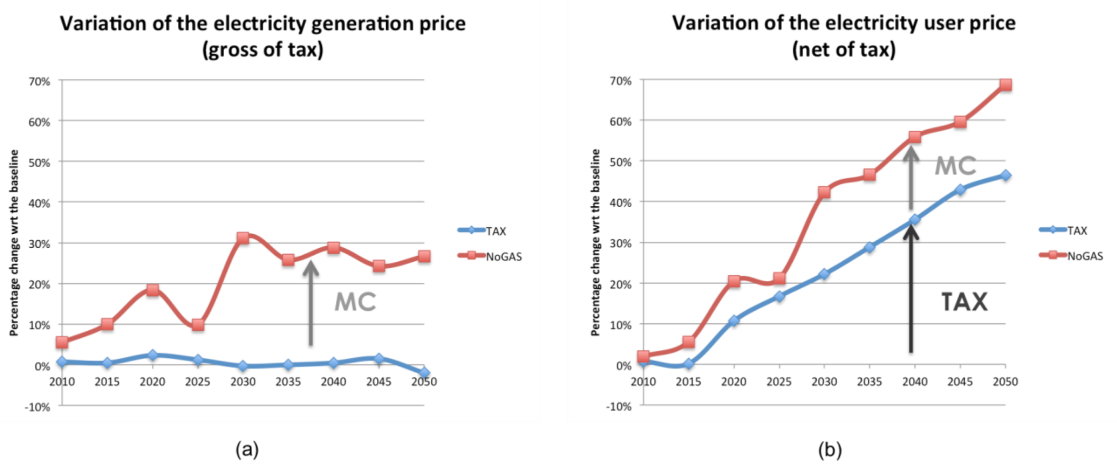
This section mainly deals with results obtained from the CROSSTEM-CH part of the coupled framework. Nonetheless, for completeness, some insights from GENESwIS are highlighted.

4.2.2.2.1 Electricity prices and demand

As mentioned in section 4.2.1.3, the CROSSTEM-CH model receives the electricity demands from GENESwIS, which is based on the electricity generation cost determined by the electricity supply mix in CROSSTEM-CH. An increase/decrease in electricity costs from CROSSTEM-CH initiates a response in GENESwIS with a corresponding decrease/increase in electricity demand, until a convergence is reached for the equilibrium supply-demand mix. Variations in wholesale electricity generation price (determined by CROSSTEM-CH) and electricity end user price (calculated by GENESwIS) for the *TAX* and *NoGAS* scenarios compared to the *Baseline* scenario are given in Figure 4-4 (a) and (b) respectively. The electricity demand variation of *TAX* and *NoGAS*, which is determined by GENESwIS and fed to CROSSTEM-CH, is given in Figure 4-5.

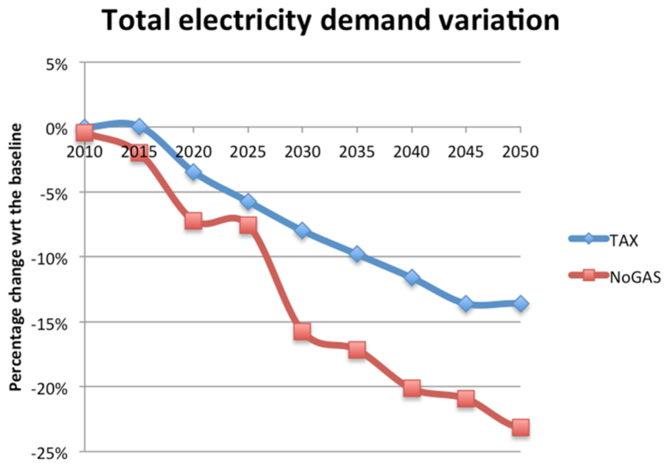
The blue line in Figure 4-4 (a) shows that the electricity generation price fed into GENESwIS from CROSSTEM-CH in *TAX* does not vary a lot in comparison to *Baseline*. As the boundary conditions for the CROSSTEM-CH model are identical in both these scenarios, the same technologies are used to satisfy the demands (see section 4.2.2.2.2), thereby resulting in similar marginal costs and hence wholesale electricity prices. The electricity user price for the end-use consumer on the other hand increases considerably (around 45% higher in 2050) in the *TAX* scenario compared to the *Baseline* (Figure 4-4 b). This change is solely due the electricity tax, which was applied in the GENESwIS model (see section 4.2.2.1.2). This increase in user price results in a reduction of electricity demand in *TAX* (blue line in Figure 4-5) compared to *Baseline*.

For the *NoGAS* scenario, boundary conditions for CROSSTEM-CH change, which results in an increase of the marginal cost of electricity (see section 4.2.2.2.3), implying a greater wholesale electricity price (red line in Figure 4-4a) and in turn a greater electricity user price (Figure 4-4b). This translates into an even further reduction of demand (red line in Figure 4-5) compared to the *TAX* scenario.



Source: ELECTRA project report

Figure 4-4: Variation of (a) wholesale electricity price (net of tax) and (b) electricity end user price (including distribution cost and tax) for the *TAX* and *NoGAS* scenarios



Source: ELECTRA project report

Figure 4-5: Variation of total electricity demand for the *TAX* and *NoGAS* scenarios with regard to *Baseline*

4.2.2.2.2 Electricity generation mix

The Swiss electricity generation mix and installed capacity from the coupled framework scenarios are given in Figure 4-6 and Figure 4-7. As mentioned before, the *Baseline* scenario follows the WWB demand from the Swiss Energy Strategy (PROGNOS AG, 2012). In this scenario, the cost optimal way to replace existing nuclear capacity is with natural gas based generation in the short to medium term, and with a combination of gas and renewables in the long term. By 2020, already 365 MW of nuclear capacity is retired (NPP Mühleberg retires in 2019), while the demand increased by 5%. To fill this supply-demand gap, the model invests in around 1.3 GW of base-load type natural gas plants[28] (see Figure 4-7). By 2035, the remaining nuclear capacity[29] is phased out and replaced by a combination of base-load (2.9 GW) and flexible (2.5 GW) gas power plants. The flexible gas generation capacity enables better supply-demand balancing in conjunction with the import/export cycles. The latter generates additional trade revenue

[28] It is worth to note that electricity imports from long-term contracts are not considered in this analysis. In the short-term, these imports would be sufficient to meet the demand. However, due to the self-sufficiency constraint, the model builds new gas plants in the short term.

[29] Although the last nuclear power plant in Switzerland (NPP Leibstadt) goes offline in 2034, 2035 still shows that 2.5% of the total electricity generation comes from nuclear. This is because the milestone year displays an average of all the years within that time period.

due to diurnal and seasonal arbitrage electricity trade, which are further discussed in section 4.2.2.2.3. By 2050, the increasing gas prices combined with technology learning (capital cost reduction) in renewable technologies leads to increasing investments in solar PV (10GW). By 2050, 52% of the net generation comes from Hydro, 32% from gas and the remaining 16% from renewables.

Compared to the *Baseline* scenario, the *TAX* scenario has a lower demand (14% lower by 2050) as shown in Figure 4-5. This is due to the demand response of GENESwIS described in section 4.2.2.2.1. Since the remaining boundary conditions for CROSSTEM-CH are unchanged between *TAX* and *Baseline* the overall generation mix and installed capacity in *TAX* are very similar to the *Baseline* scenario. While the total capacity of hydro and nuclear technologies remains unchanged with respect to *Baseline*, there is a proportionate reduction in gas based generation due to the lower demand. Hence in *TAX*, the system has an installed gas capacity of 1 GW by 2020, 4.1 GW by 2035 (vs. 5.4 GW in *Baseline*) and 3.1 GW (vs. 4.7 GW in *Baseline*) by 2050. The solar PV generation remains unchanged from the *Baseline* scenario, i.e. full potential is tapped by 2050. The self-sufficiency constraint prevents the model from increasing domestic production and exporting the excess electricity.

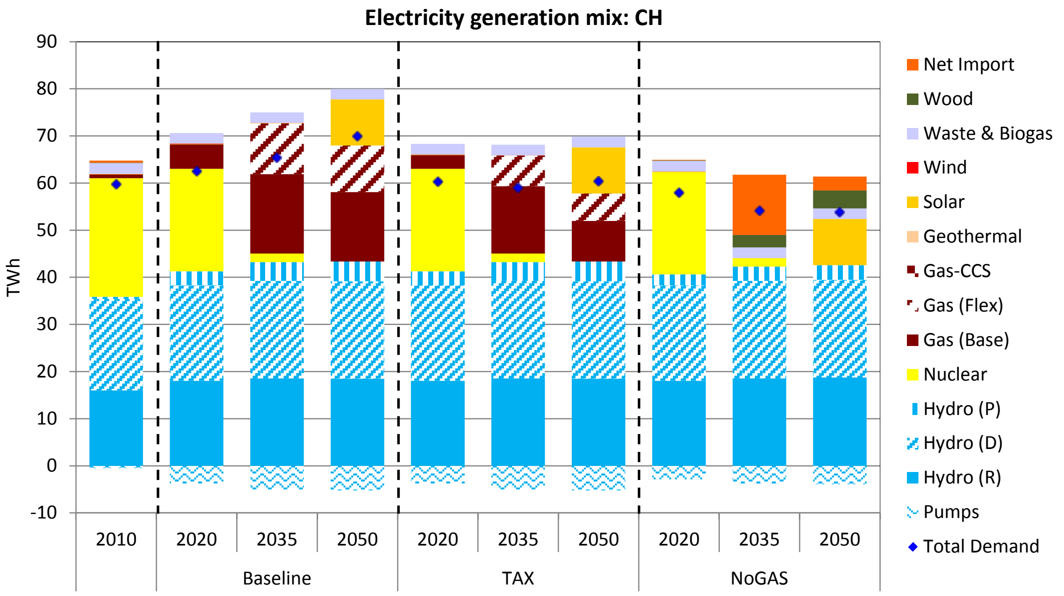


Figure 4-6: Electricity generation mix (Switzerland)

The *NoGAS* scenario provides a very different picture compared the other two scenarios. This scenario has an even lower demand than the *TAX* scenario (23% lower than *Baseline* and 11% lower than *TAX* by 2050, see Figure 4-5). This further lowering of demand is due to the supply mix of CROSSTEM-CH for *NoGAS*, which increases the electricity production marginal cost compared to *TAX*.

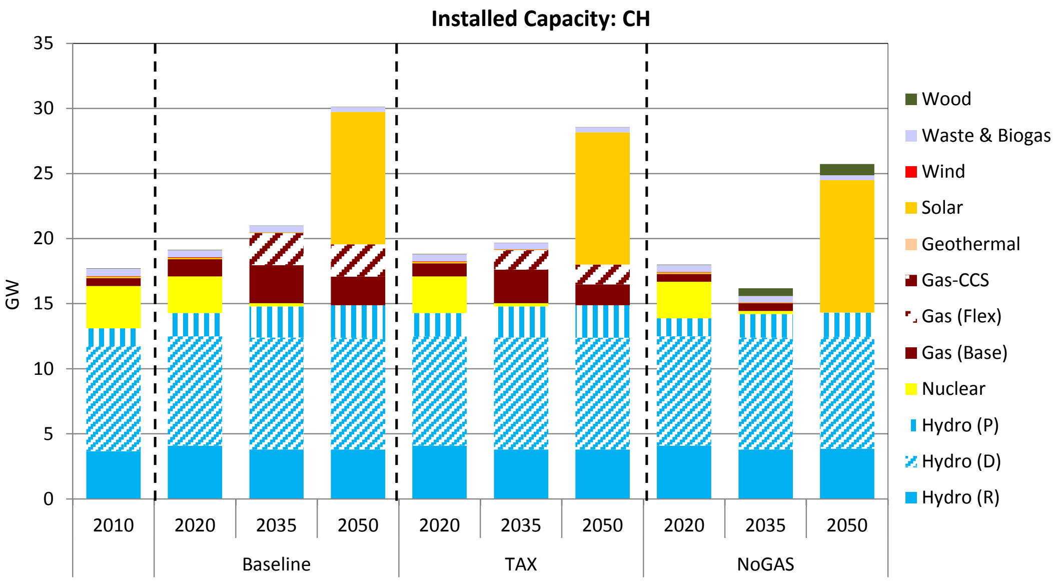


Figure 4-7: Installed Capacity (Switzerland)

Since no natural gas based generation is allowed in this scenario, the model is allowed to import electricity to the same level as gas imports for electricity production in the *TAX* scenario (see scenario definition in section 4.2.2.1.3). In the near term (2020), due to the lowering of the demand, the existing nuclear, hydro and renewable capacities are almost sufficient to supply the demand (only 0.14 TWh of net imports in 2020). By 2035, when all the nuclear capacity has been retired, the model finds it cost optimal to import most of the retired nuclear generation equivalent (around 13 TWh, or 22% of the total demand), with some investment in biomass fired power plants provide seasonal base-load (0.6 GW by 2035). The costs of other new renewable technologies such as solar PV are still not cost competitive in 2035 compared to the assumed electricity import prices from the surrounding regions (Kannan et al., 2011). As with the other scenarios, solar PV becomes competitive by 2050 due to increasing price of imported electricity as well as cost reductions in renewable based generation. The available solar potential is fully tapped by 2050 (10 GW). Nonetheless, a net import of around 3 TWh (about 5% of the total demand) is still required to meet the electricity demand.

4.2.2.2.3 Generation schedule

One of the main features of the CROSSTEM-CH model is its ability to depict hourly load patterns. The hourly electricity supply and demand balance curves of Switzerland in the *TAX* scenario for an average weekday for all four seasons in 2050 are shown in Figure 4-8. Generation schedules for the other scenarios are shown in Figure 4-9 and Figure 4-10. The upper panel in Figure 4-8 shows the dispatch schedule of various power plants, with the blue line indicating the demand and red line showing the marginal cost of electricity. The bottom panel highlights the dispatch of excess electricity, which is either exported (grey area) or stored via pumped hydro systems (blue area).

Load Curve – TAX (2050)

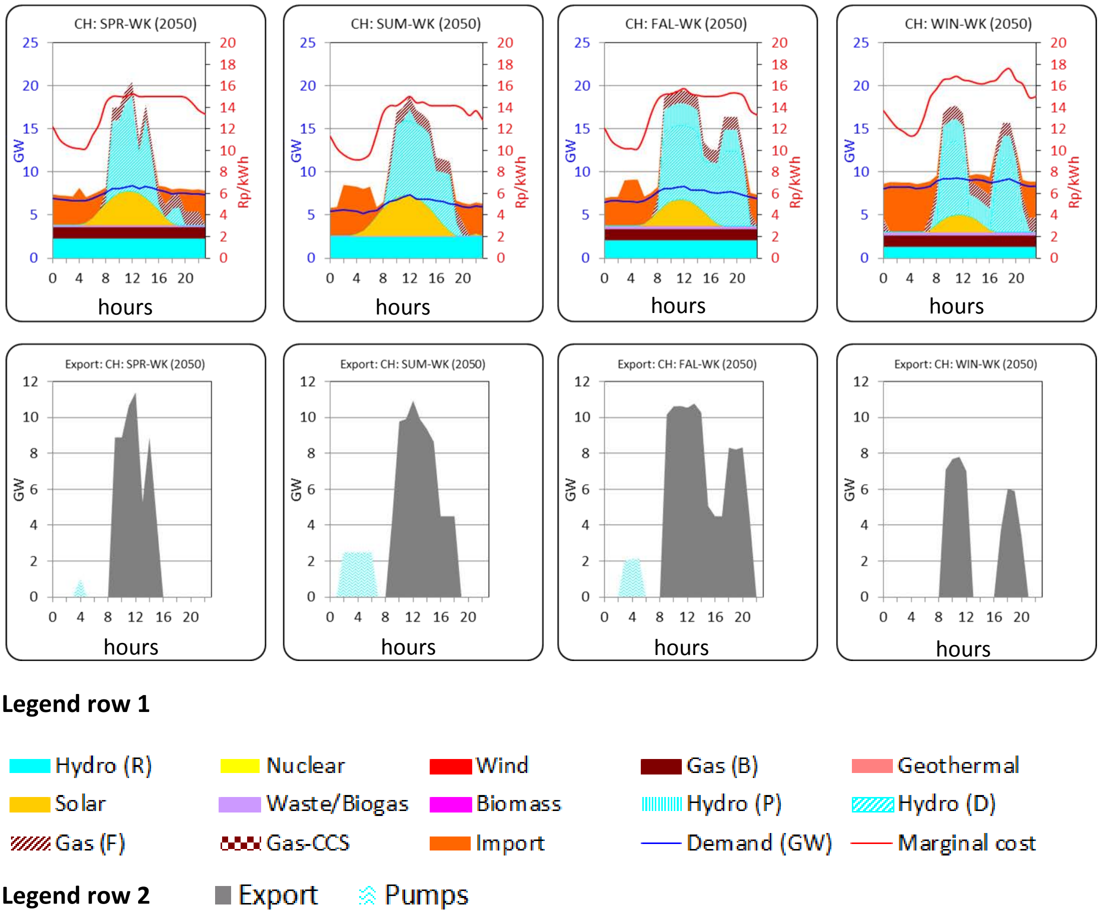


Figure 4-8: Electricity generation schedule on weekdays (2050) – *TAX*

It can be observed that the base-load generation (river hydro and base-load gas plants) only covers around half of the demand, even during the summer when the demand is lowest. Since there is a large installed capacity of solar PV, this covers the peak time (08:00-16:00), with imports required during the early morning hours as well as evening and/or night hours for all the four seasons. In spring and summer, solar availability is high (see Figure A16 in Appendix A), and combined with flexible dam hydro and flexible gas based production, covers the peak demand adequately. Switzerland also generates excess electricity during these peak hours by scheduling dam hydro plants, with the surplus electricity being exported. During the early morning (00:00-08:00) and late evening (20:00-00:00) hours, when electricity import prices are assumed to be cheaper, Switzerland imports the electricity to cover its demand as well as store the electricity using pumped hydro (see bottom panel in Figure 4-8).

In autumn (fall), electricity schedule patterns are similar to summer and spring, but an additional export peak occurs during the evening hours. The underlying driver for this second peak is again the import/export price assumptions (see Figure 4-27), with the model maximizing the amount of exports at these high price hours to generate more revenue. Although there is a reduction in solar PV output compared to summer and spring, it is compensated by flexible dam hydro generation, whose availability is highest during fall (see section 3.4.4.2 in chapter 3).

The generation schedule in winter is very similar to that in autumn. Since solar PV and dam hydro availabilities are at their lowest in winter, the demand is met with base-load gas plants and imports. Imports occur almost throughout the day, except for a few hours around noon (09:00-12:00) and in the evening (17:00-19:00) when import/export prices are assumed to be high. The dam hydro generation is scheduled in those hours to meet the demand as well as to export electricity at high prices. Dam hydro is used in this manner to exploit the export prices, finding it more cost effective instead of using it more evenly throughout the day to minimize the imports.

The hourly generation profile of the *Baseline* scenario is very similar to the *TAX* scenario; only the magnitude of the demand differs and accordingly the gas based generation is increased in *Baseline* (see Figure 4-9 and Figure 4-10). This also explains why the marginal cost (red line in upper panel of Figure 4-9 and Figure 4-10) does not vary much across both these scenarios, as both scenarios have the same marginal technology (also see section 4.2.2.2.1, Figure 4-4).

For the *NoGAS* scenario, the generation schedules still have a lot of similarities with the other two scenarios, with the obvious exemption of gas based generations. In summer (Figure 4-9) and spring (not shown), the model optimizes the use of flexible hydro and imports to complement the steady outputs from solar PV and base-load river hydro. Import and export patterns are also similar, but due to the lower generation capacities, there is a corresponding reduction in the export volumes as well.

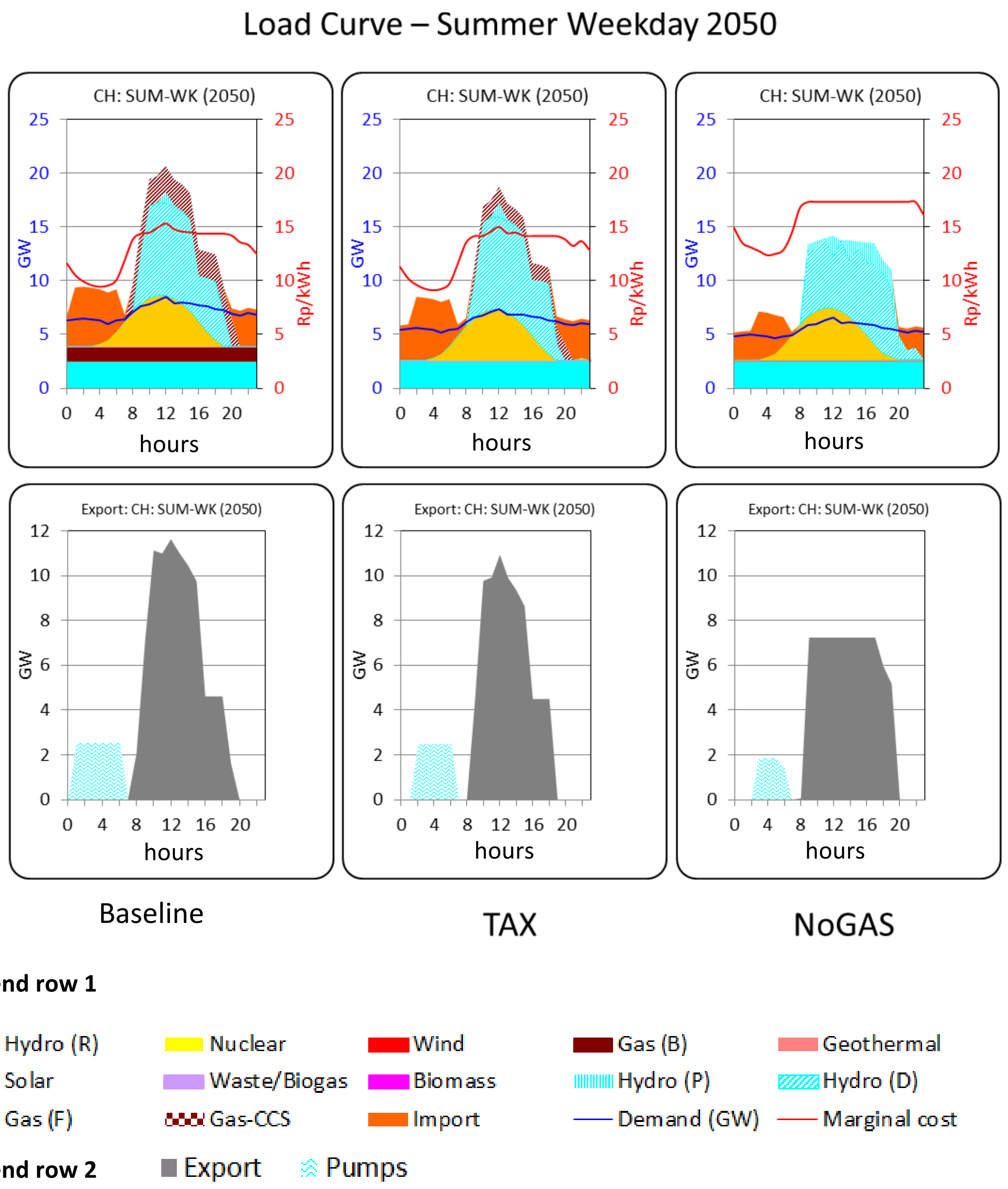


Figure 4-9: Electricity generation schedule on a summer weekday (2050)

In fall (not shown) and winter (Figure 4-10), base-load generation from river hydro is supplemented by biomass and geothermal sources. As with the previous scenarios, electricity is imported throughout the day except for the two high price peaks (noon and evening), and the flexible hydro plants are scheduled at these hours to maximize exports at higher prices and generate more trade revenue. The increasing dependence on expensive electricity imports is also reflected in the marginal price, which is highest for the *NoGAS* scenario amongst the three scenarios. It is this increase in marginal price that induces the lowering of the demand in *NoGAS* even further by GENESwiS (see section 4.2.2.2.1).

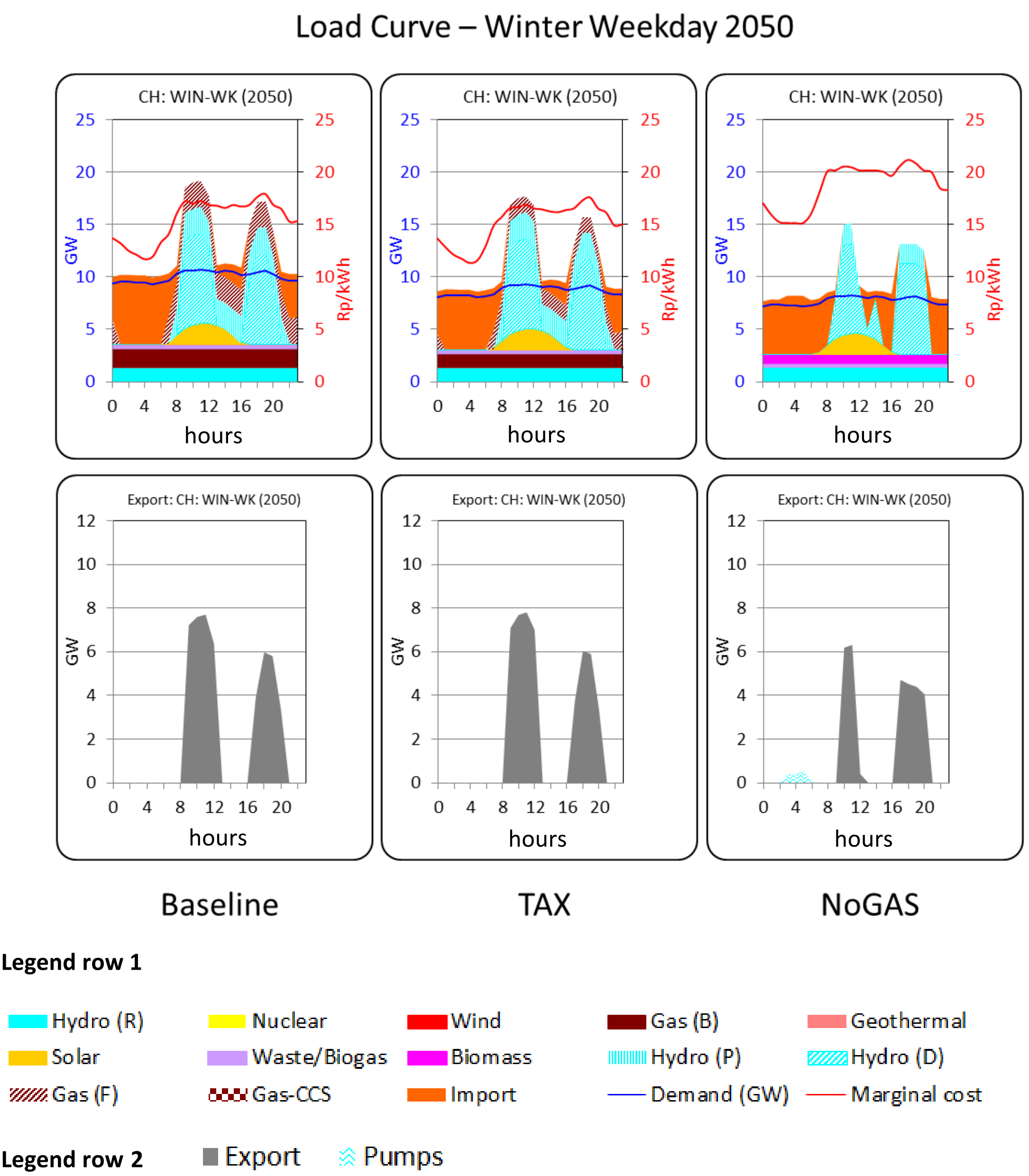


Figure 4-10: Electricity generation schedule on a winter weekday (2050)

4.2.2.2.4 CO_2 emissions

CO_2 emissions from the electricity generation sector for all three scenarios are given in Figure 4-11. For both the *Baseline* and *TAX* scenarios, there is an initial increase in the CO_2 emissions, reaching a peak value of 10.8 Mt CO_2 in 2045 for the *Baseline* scenario, and 7.6 Mt CO_2 in 2040 for the *TAX* scenario. Increasing gas prices combined with the higher CO_2 tax result in increasing penetration from solar PV, which lowers the emissions by 2050. The *NoGAS* scenario does not have direct CO_2 emissions from the electricity sector; however CO_2 emissions associated with imported electricity are not considered in this study.

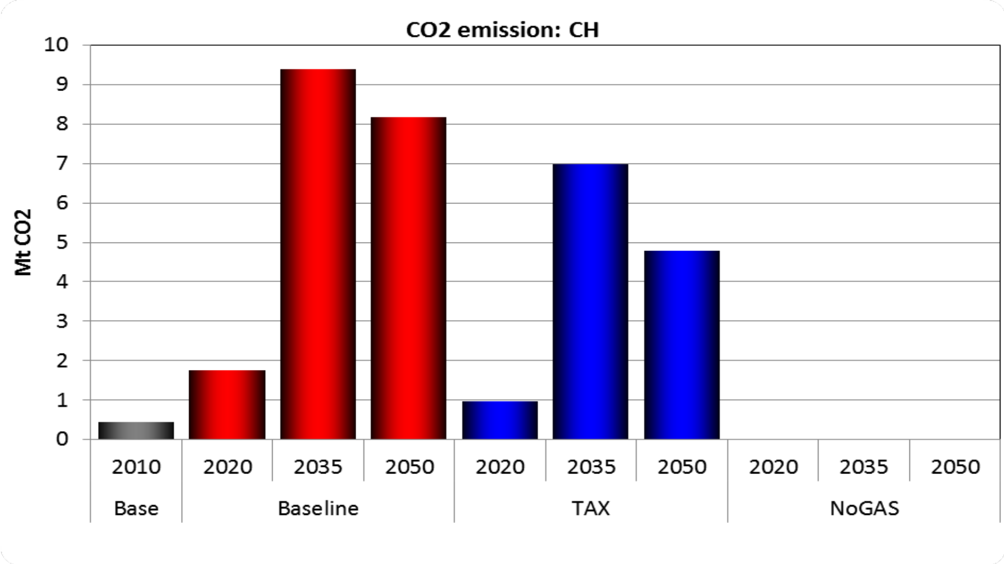


Figure 4-11: CO2 emissions (Electricity sector)

4.2.2.2.5 Electricity supply system cost and average electricity cost

Figure 4-12 shows the annual undiscounted electricity supply system costs, for all three scenarios. The costs are shown for various cost components such as capital costs (annuities on investments), taxes (e.g. levy on nuclear spent fuel and CO_2 tax), fixed and variable operation and maintenance costs, fuel costs and trade balances (which refer to net profits if negative or cost if positive) from electricity import or export. The net electricity supply system cost for each scenario is also shown in the figure (blue marker).

One can see the increasing electricity system cost as we move from 2010 to 2050 in all three scenarios. For the *Baseline* scenario, in the near to medium term (2020, 2035) the main cost component is the fuel costs – reflecting the higher share of gas-based generation and increasing natural gas price assumptions. The high CO_2 emissions in this scenario are also reflected in the costs via the tax component (CO_2 taxes). By 2050, the fuel cost and taxes are stable due to partial replacement of gas plants with solar PV, which in turn drastically increases the capital costs.

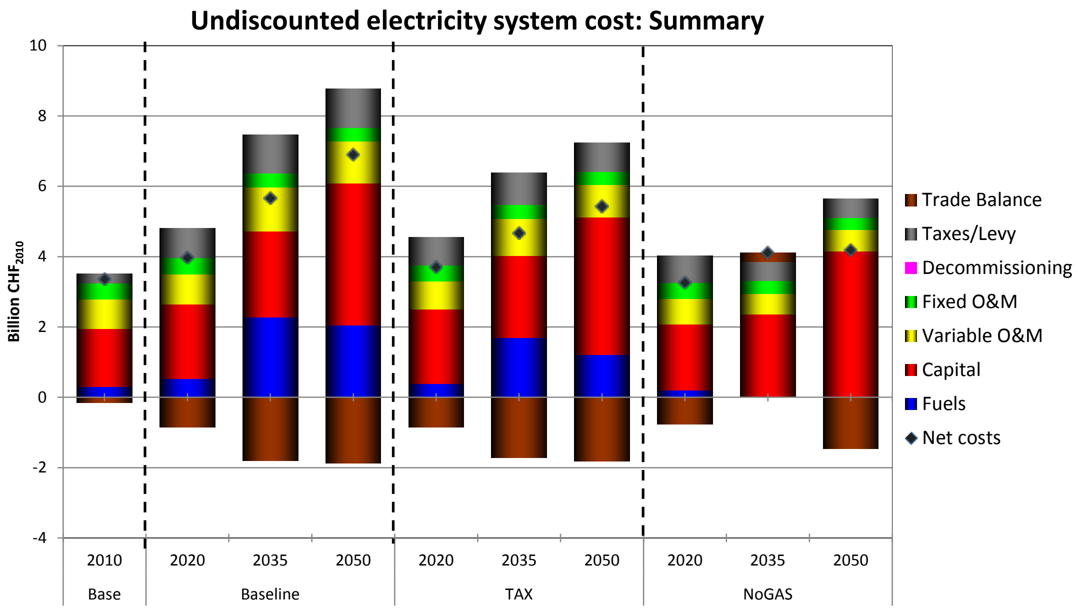


Figure 4-12: Undiscounted electricity system cost: Switzerland

The cost pattern for the *TAX* scenario is similar to the *Baseline* scenario, but with a slightly lower magnitude of costs due to the lower capacities required to supply the lower demand. It is worth remembering that the electricity tax is applied in the CGE model for the electricity consumption. Therefore there is no significant change in the tax component of the electricity supply system cost.

For the *NoGAS* scenario, with overall electricity demand being the lowest, there are no large investments in the near to medium term (2020, 2035), which reduces the total electricity system cost with respect to the other scenarios. With no gas based production, there is no CO_2 tax or fuel cost to be accounted for. In 2035, Switzerland requires net imports to meet the demand (22% of the demand is imported). But by optimising the timing of imports and exports, the net import cost only accounts for 8% of the total electricity system cost. By 2050, higher investments in renewable technologies (solar PV, see Figure 4-7) coupled with a lowering of the electricity demand reduces the dependence on expensive electricity imports. This results in a trade revenue surplus, which in turn offsets the increasing capital cost of renewable technologies and keeps the net costs even lower than the other two scenarios.

The differences in the total system costs across the three scenarios are also reflected in the average electricity cost. The average cost of electricity declines by 9% in 2050 for the *TAX* scenario compared to the *Baseline* scenario (see Figure 4-13). The total electricity system cost and thereby the average cost of electricity in the *NoGAS* scenario decreases even further (30% decrease in average cost by 2050 compared to *Baseline*).

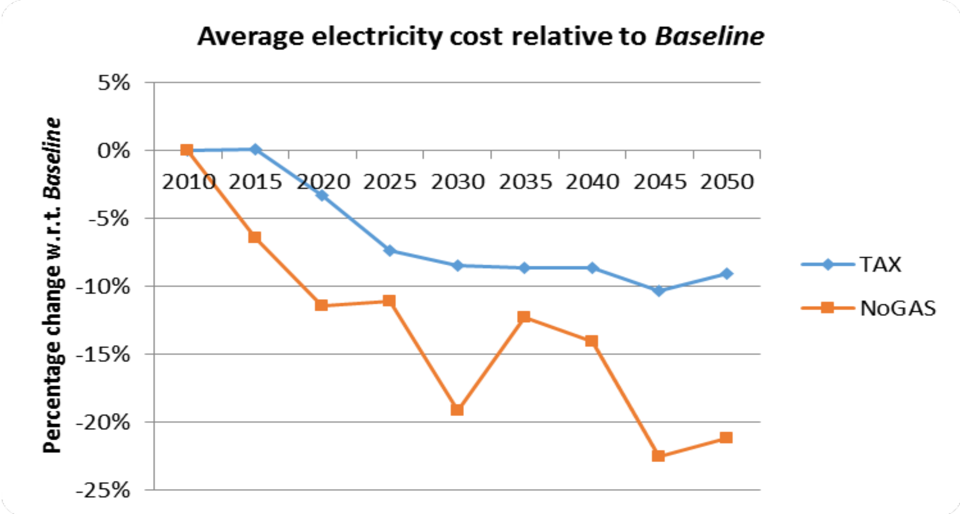


Figure 4-13: Relative average electricity cost (*TAX*)

4.2.3 Comparison of ELECTRA-CH framework with the stand-alone CROSSTEM-CH model

The most obvious advantage of the coupled model over a stand-alone bottom-up model is the demand feedback. As seen in the results section (4.2.2.2), increasing electricity prices from the CROSSTEM-CH model triggered a reduction of electricity demand in the GENESwIS model, which was eventually fed back to the CROSSTEM-CH model. In a stand-alone CROSSTEM-CH model, this is not possible, since the electricity demand is inelastic to price changes. Any increase in cost factors both internally or externally (through an electricity tax like in the *TAX* scenario, section 4.2.2.1.2), only increases the cost of production and gives a higher electricity generation cost. A partial equilibrium bottom-up modelling framework like TIMES does however have the possibility for inherent demand feedback via the use of exogenously defined demand elasticities (Loulou et al., 2005). However, defining such elasticities is an arduous task, as they are highly uncertain and vary over time, and was out of the scope of this project. Hence, the ELECTRA-CH framework can give insights which the stand-alone CROSSTEM-CH model cannot generate.

Besides the electricity demand feedback, the coupled framework also incorporated sectoral price feedbacks from the GENESwIS model to CROSSTEM-CH. This was to analyse how changes in different sectoral costs (for example labour costs) affected capital or operational costs of power plants in the CROSSTEM-CH model.

The price feedback is achieved via the estimation of price-variation coefficients in GENESwIS, which would modify investment as well as O&M costs of various technologies in CROSSTEM-CH. The price coefficients are calculated as the weighted average of price variations in different sectors of GENESwIS such as labour, metals, cement etc. Coefficients are calculated for five technology groups in CROSSTEM-CH, namely: gas, hydro, solar, other renewables and nuclear. Coefficients are separately calculated for investment costs and O&M costs. The price coefficients exchanged in ELECTRA-CH for the *TAX* scenario is shown in Figure 4-14.

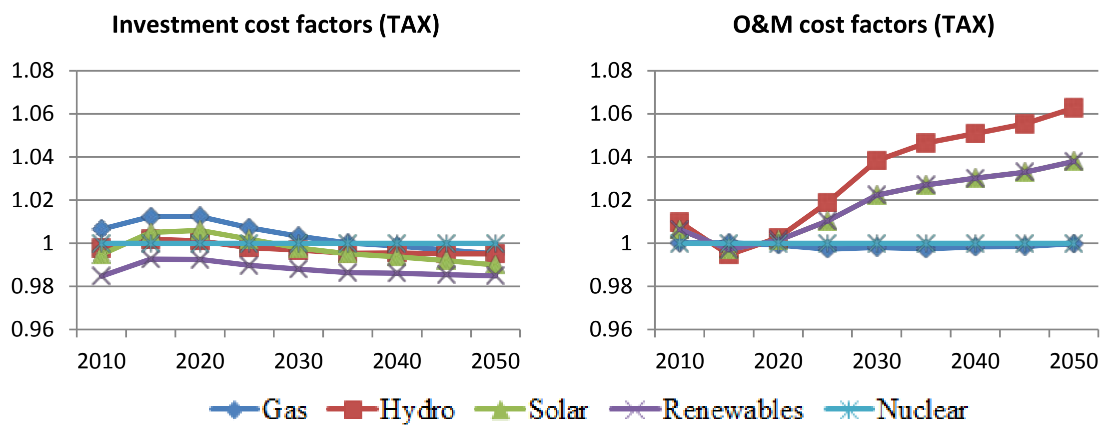


Figure 4-14: Price-variation coefficients for the *TAX* scenario

In order to highlight the impact of the price variation coefficients, the electricity supply mix results of the *TAX* scenario discussed in section 4.2.2.2.2 (referred to as “Couple” for the current analysis) is compared to results from a standalone CROSSTEM-CH model without price feedbacks (referred to as “Standalone”). The “Standalone“ model uses the electricity demand assumptions from the *TAX* scenario, but does not multiply investment and O&M cost with the price-variation coefficients.

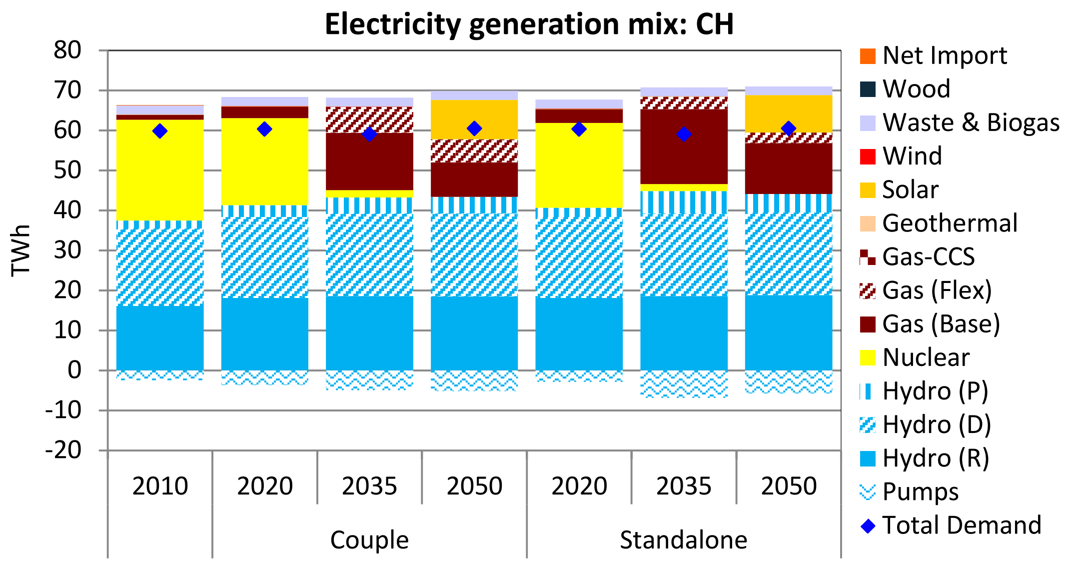


Figure 4-15: Electricity generation mix (Switzerland–*TAX*) - Coupled vs uncoupled

As seen from Figure 4-14, the investment cost for gas and hydro technologies are higher during the initial time periods, but then decrease towards the end of horizon (variations are small, within ± 2%). The O&M costs for gas plants do not change much over the same time period, whereas they increase considerably (up to 6% by 2050) for the hydro technologies. This implies that for a coupled run, the cost of operating hydro technology is higher than for a standalone run. This is reflected in the generation mix presented in Figure 4-15, which shows a higher output from pumped hydro (which is the most expensive hydro option available) for the standalone run compared to the coupled run. To overcome this lost flexibility, the coupled model invests in more flexible gas generation technology (in 2035, 30% of the total gas based generation comes from flexible gas plants in the coupled run, compared to 14% in the standalone run). Similar patterns are observed for the other two scenarios as well.

This highlights another advantage of the coupled framework, and demonstrates that coupling top-down and bottom-up models matter.

4.3 Application of the full CROSSTEM framework

In this section, results are presented to demonstrate the features and capabilities of the full CROSSTEM model and highlighting its advantages over the single region models such as STEM-E (or CROSSTEM-CH, described in the previous section). A set of scenarios with different boundary conditions on electricity trade and technology development in Switzerland and the neighbouring countries are presented in the following subsections.

4.3.1 Input assumptions

Some key assumptions that are common to all scenarios are described below.

4.3.1.1 Electricity demand

Swiss electricity demand is adopted from the WWB scenario in the Swiss Energy Strategy 2050 (PROGNOS AG, 2012). The electricity demands for the neighbouring countries are taken from a business as usual scenario of the GEMINI-E3 model (Bernard et al., 2009) (see Figure 4-16). The business as usual scenario of the GEMINI-E3 model has more stringent boundary conditions compared to the WWB scenario for Switzerland, which is reflected in the lower electricity demand growth projection for the neighbouring countries. Chapter 5 explores alternative electricity demand assumptions for the surrounding countries.

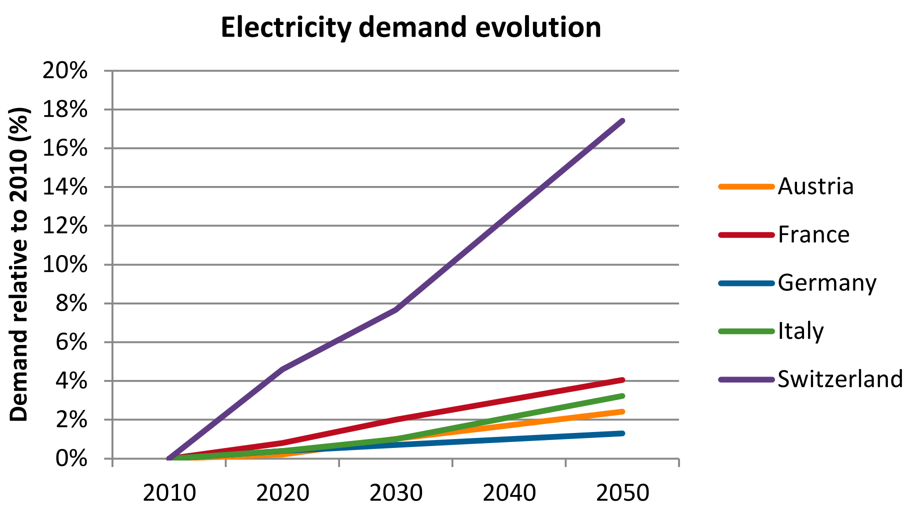


Figure 4-16: Electricity demand in CROSSTEM

4.3.1.2 Technology restrictions

Nuclear power is assumed to be phased out in Switzerland by 2034, in Germany by 2023. France is allowed to replace its existing nuclear fleet, with new capacities not allowed to exceed 2010 capacity levels (i.e. nuclear power plant investments in “green fields” are not allowed). Nuclear investment is not expected in Austria and Italy.

Investment in coal power is not enabled in Switzerland, following the assumptions in the Swiss energy strategy (PROGNOS AG, 2012). For neighbouring countries, a growth constraint is applied for new investments in coal and lignite[30] fired power plants based on the coal capacity expansion in Germany in the last 15 years. This is to prevent unrealistic capacity expansions in coal based power plants in lieu of the nuclear phase-out.

4.3.1.3 Electricity trade

Historical patterns in electricity trade were kept as a boundary condition for these initial set of scenarios. Hence, traditional net importers of electricity (i.e. Italy and Austria) cannot become net exporters and traditional net exporters (France and Germany) cannot become net importers in future. These market/boundary conditions are very crucial assumptions, and small changes to these conditions would significantly affect the results (alternative scenarios without trade constraints are presented in Chapter 5). At the same time, the possibility to assess different boundary conditions with CROSSTEM under what-if analysis constitutes a strength of the framework developed in this thesis.

All other assumptions such as international energy prices, CCS potentials and CO_2 taxes have already been described in Chapter 3.

4.3.2 Scenario Overview

Three electricity supply scenarios have been analysed in this section using the business as usual (WWB) electricity demand of the Swiss Energy strategy 2050. The scenarios are consistent with earlier studies analysed using the STEM-E model (Paul Scherrer Institute, 2012). However, CROSSTEM has an improved framework with better representation of the international boundary conditions, which enables endogenous cross border electricity trade. The model bases the electricity trade on marginal costs of electricity generation in the neighbouring countries by accounting for the sources of

[30] Available for Germany only.

electricity import and market for electricity export. The three scenarios comprise of a common set of assumptions and scenario specific boundary conditions, which are chosen to generate insights on the influences of policies in the neighbouring countries on the Swiss electricity system. Table 4-1provides an overview of the scenarios.

Table 4-1: CROSSTEM scenario matrix

	Framework →		CROSSTEM		
	Scenario name		Sc.1	Sc.2	Sc.3
	Scenario description		Baseline	Baseline$_{CH}$-LC$_{EU}$	NoGas$_{CH}$-LC$_{EU}$
Switzerland	Electricity demand		WWB	WWB	WWB
Switzerland	Electricity supply variants	Gas plants	Yes	Yes	No
Switzerland	Electricity supply variants	Imports	No self-sufficiency#	No self-sufficiency#	Yes*
Switzerland	CO_2 cap		No	Yes^	Yes^
EU boundary	Electricity demand		WWB	WWB	WWB
EU boundary	CO_2 cap		No	Yes (95% by 2050)^	Yes (95% by 2050)^

Notes:
* Import is allowed up to an equivalent gas-based supply from the Baseline
^ Applied on all 5 countries together
# Self sufficiency constraint for CH
Sc.1 → Sc.2, price of imported electricity is expensive because EU shift towards low carbon /clean source of electricity
Sc.2 → Sc.3, CH does not have cheap electricity from gas and relies on imported electricity to meet the demand
CO2 price – EU ETS prices as given in WWB, for all scenarios.

4.3.2.1 Scenario 1 (Sc1)

This scenario can be described as a business as usual scenario and is comparable to the *Gas* scenario in Energie Spiegel Nr. 21 (Paul Scherrer Institute, 2012), i.e. Switzerland has the option to build new gas power plants while the neighbouring countries have much wider range of electricity supply sources including coal and nuclear power. *Sc1* directly corresponds to the *Baseline* scenario discussed in the coupled framework (see section 4.2.2.1.1). Switzerland is assumed to be self-sufficient in electricity supply over the year, i.e. annual net electricity imports/exports are not allowed. However, net imports/exports are allowed on hourly/weekly and seasonal levels.

4.3.2.2 Scenario 2 (Sc2)

This scenario is a variant of *Sc1*, where a decarbonization of the entire power sector is envisaged in Switzerland and the neighbouring countries. The CO_2 emissions from all the five CROSSTEM countries are to be reduced by 95% of 1990 levels (or about 94% of 2010 levels) by 2050. Note that the ***CO_2 cap is applied across all five regions*** in the model and is not country specific. Thus the model identifies least cost sources of low carbon electricity supply subjected to the technical, resources and trade constraints. This scenario highlights the influence of the neighbouring countries' electricity system on the Swiss electricity supply and operational patterns.

4.3.2.3 Scenario 3 (Sc3)

This scenario is same as the *Sc2* scenario, with an additional constraint included in Switzerland that ***restricts investment in new gas power plants***. Since the assumed renewable resource potential in Switzerland is not adequate to meet the WWB electricity demand, the self-sufficiency constraint has been relaxed so that Switzerland can become a ***net importer of electricity***. However, the level of net electricity imports is limited to the level (in PJ) of gas imports in the *TAX* scenario of the coupled framework. It is worth noting that relaxing the self-sufficiency constraint enables the model to import cheap electricity from the neighbouring counties, if cost effective. This scenario is analogous to the *NoGAS* scenario in the coupled framework.

4.3.3 Results

This section details the results of the CROSSTEM scenarios described above. The results discussed here mainly focus on Switzerland, with detailed results of the neighbouring countries given in Appendix B. In section 4.3.4, results from the CROSSTEM model are compared to results from the single region CROSSTEM-CH model to highlight the benefits of the new framework.

4.3.3.1 Electricity generation mix

The Swiss electricity generation mix and installed capacity for the three scenarios are given in Figure 4-17 and Figure 4-18 respectively. In the *Sc1* scenario, new gas power plants (both base-load and flexible plants) gradually replace the existing nuclear plants. By 2020, 365 MW of nuclear capacity is retired (Mühleberg in 2019), while the electricity demand increases by 5%. This time, the model invests in around 1.9 GW of base load type natural gas generation capacity. By 2035, the remaining nuclear capacity[31] is replaced by a combination of base-load (4.2 GW) and flexible (3.2 GW) gas power plants. The flexible gas generation capacity enables better supply-demand balancing in conjunction with the imports/exports from the neighbouring countries, which also enables Switzerland to generate more trade revenue by exporting more electricity during peak hours (see section 4.3.3.3). By 2050, 51% of the generated electricity is from hydro, 46% from gas power plants and the remaining 3% from new renewables (primarily waste and biogas).

In *Sc2*, the electricity generation mix in the near term (2020) appears identical to that in *Sc1*, but the total installed capacity of gas plants is 3 GW compared to 1.9 GW in *Sc1*. The higher installed capacity is because of the higher costs of imported electricity in *Sc2*, especially in winter due to the CO_2 constraints. In other words, sources of low carbon electricity in winter are expensive in neighbouring countries mainly due to expensive renewable technology costs during the earlier periods. Hence the model minimises imports during certain hours (see section 4.3.3.2)) by generating more electricity locally, especially in winter, which in turn reduces the total capacity factor of the gas plants. By 2035, investments in gas CCS (carbon capture and storage) as well as wind technology are required to comply with the CO_2 emission cap. By 2050, all thermal power is produced by gas CCS power plants (3.1 GW, 29% of total generation), while solar PV, wind and other renewables contribute to around 20% of the generation mix. Investments in renewable technologies are required due to the CO_2 emission cap, as well as the self-sufficiency constraint. The emission cap prevents more investments in gas CCS plants due to residual emissions (CCS plants capture only 90% of the total emissions), while the self-sufficiency constraint prevents the import of cheap electricity from the neighbouring countries. The higher cost of electricity also means reduced pumped hydro usage compared to *Sc1*, due to the associated energy losses in pumped

[31] Although the last the last nuclear power plant in Switzerland (NPP Leibstadt) goes offline in 2034, 2035 still shows that 2.5% of the total electricity generation comes from nuclear. This is because the milestone year displays an average of all the years within that time period.

hydro.

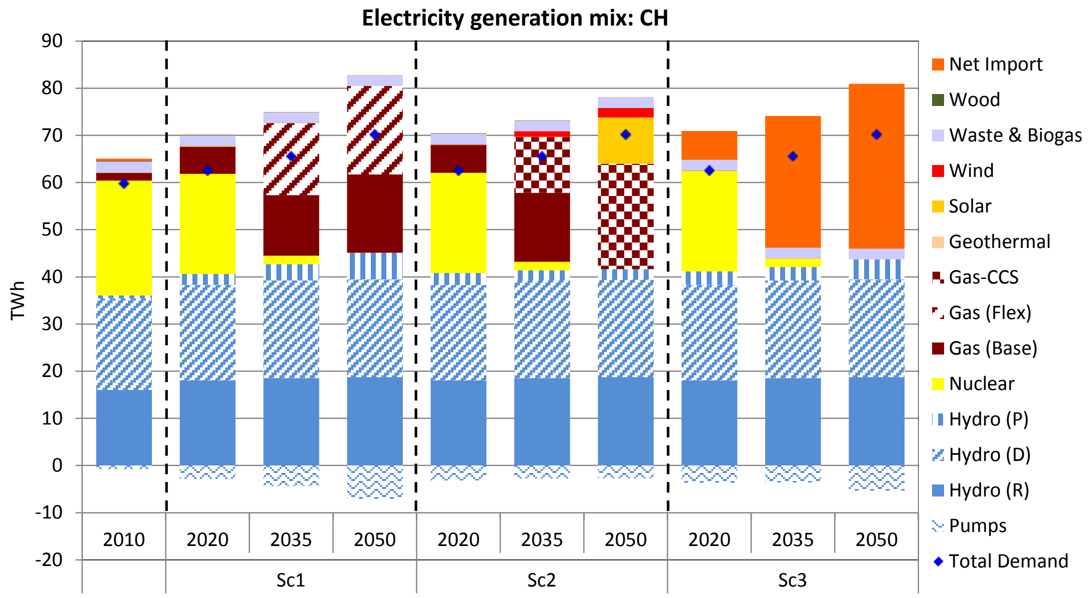


Figure 4-17: Electricity generation mix (Switzerland)

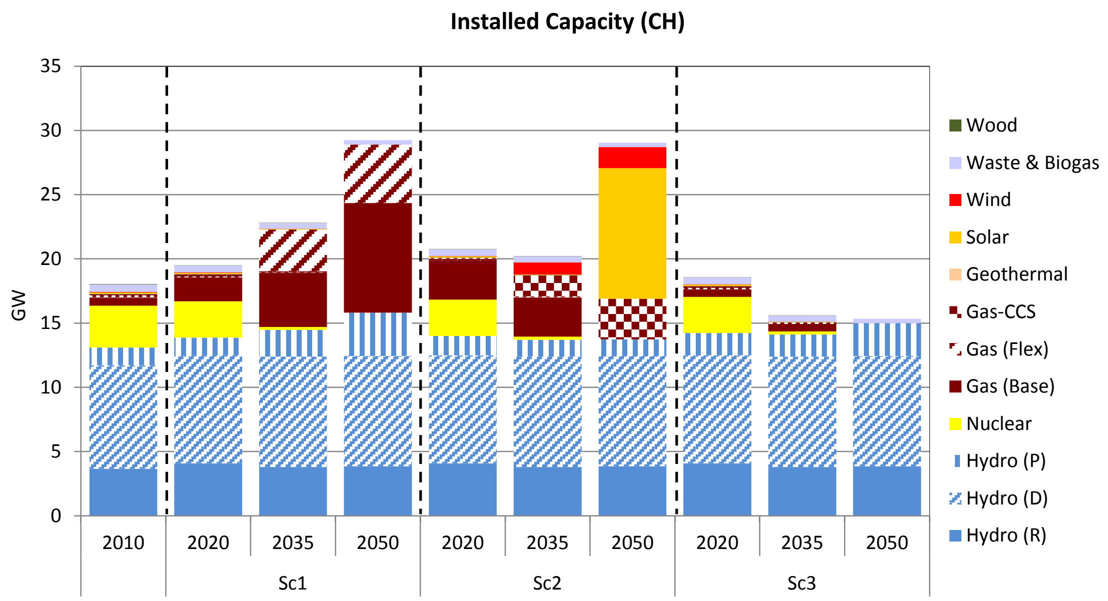


Figure 4-18: Installed capacity (Switzerland)

In *Sc3*, due to the restriction on investments in gas plants and relaxation of the self-sufficiency constraint, the most cost effective option for Switzerland is to replace the existing nuclear capacity with imported electricity. By 2035, almost 40% of the electricity demand is imported, and by 2050 the share of imported electricity increases to 46%. By relaxing the self-sufficiency constraint, Switzerland is able to import cheap electricity from neighbouring countries, rather than having to build expensive gas CCS plants or renewables which have less favourable conditions in Switzerland (e.g. lower capacity factors for solar PV in Switzerland compared to Italy, or for wind technology compared to Germany), which was the case in *Sc2*. How and where the additional investment is made in order for Switzerland to import the electricity is shown in Figure 4-19.

The figure shows the relative share of electricity generation mix of the five countries for the base year (2010) and the year 2050 for all three scenarios. Since the boundary conditions for the neighbouring countries are identical for both *Sc2* and *Sc3*, the difference in the electricity generation mix between these two scenarios is caused by the relaxation of the self-sufficiency constraint in Switzerland. It is observed that for Italy, Austria and Germany, there are no visible variations in the electricity generation mix between the two scenarios. France on the other hand has an increased share of renewables in *Sc3* compared to *Sc2*. In fact, France invests in an extra 15 GW of wind capacity and 2 GW of solar PV capacity in *Sc3* compared to *Sc2* (see Figure B1 in Appendix B). Both wind and solar PV technologies are more cost competitive than gas CCS plants by 2050, which prompts Switzerland to import the cheaper electricity from France. At the same time, France has to invest in higher renewable capacity, but generates additional trade revenue by exporting the electricity to Switzerland. It is worth recalling that due to the trade constraints (see section 4.3.1.3), only France and Germany can be net exporters, which limits other regions from investing in higher renewable capacities. It is also important to note that the ‘no gas plants’ constraint does not affect the results for Switzerland (i.e. the constraint is loose) and the relaxation of the self-sufficiency constraint is enough to obtain the results discussed above. This indicates that the limits on net imports is quite generous (120 PJ or 33 TWh in 2050, see Figure B7 in Appendix B), as there is still unexploited renewable potential in Switzerland. Nonetheless, the restriction on gas plants is still applied to be consistent with the coupled framework scenarios (*NoGAS* scenario, section 4.2.2.1.3).

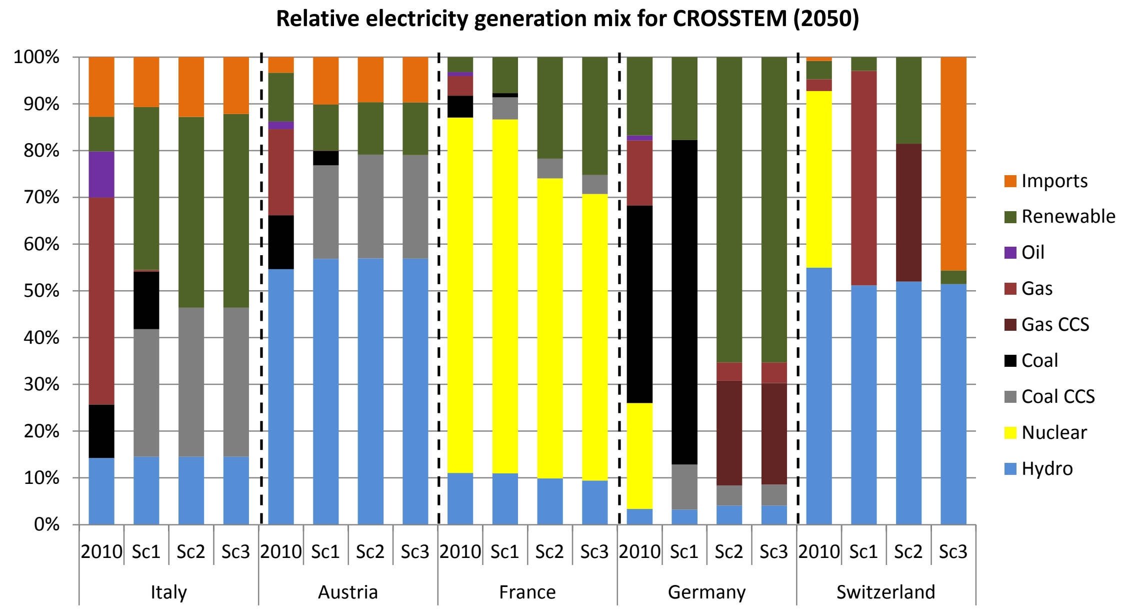


Figure 4-19: Electricity generation mix CROSSTEM countries (2050)

4.3.3.2 Generation schedule

As mentioned before, one of the main features of the CROSSTEM model is its ability to depict hourly electricity load patterns. The hourly supply and demand balance curves of Switzerland for a winter weekday in 2050 for all three scenarios is shown in Figure 4-20. In the figure, electricity demand (blue line) and supply mix are shown in the upper panel, while the lower panel depicts electricity export (grey shade), and consumption by pumped hydro (light blue shade). The red line in the upper panel is the marginal cost of electricity supply. Unlike dispatch-type models, the marginal cost from CROSSTEM is not the short-run marginal cost of generation, but the long-run marginal cost of electricity by accounting for investment costs of capacity.

In *Sc1*, electricity supply from base load generation plants (natural gas and river hydro) covers almost 84% of the demand. The rest of the demand is met with a combination of imported electricity (during early morning hours 00:00-08:00) and flexible gas and dam hydro plants (scheduled during 08:00-22:00). Some of the imports are stored via pumped hydro during 03:00-05:00. The surplus electricity production from the gas and hydro plants are exported. In addition, the pumped hydro is also scheduled during 8:00-22:00 and exported.

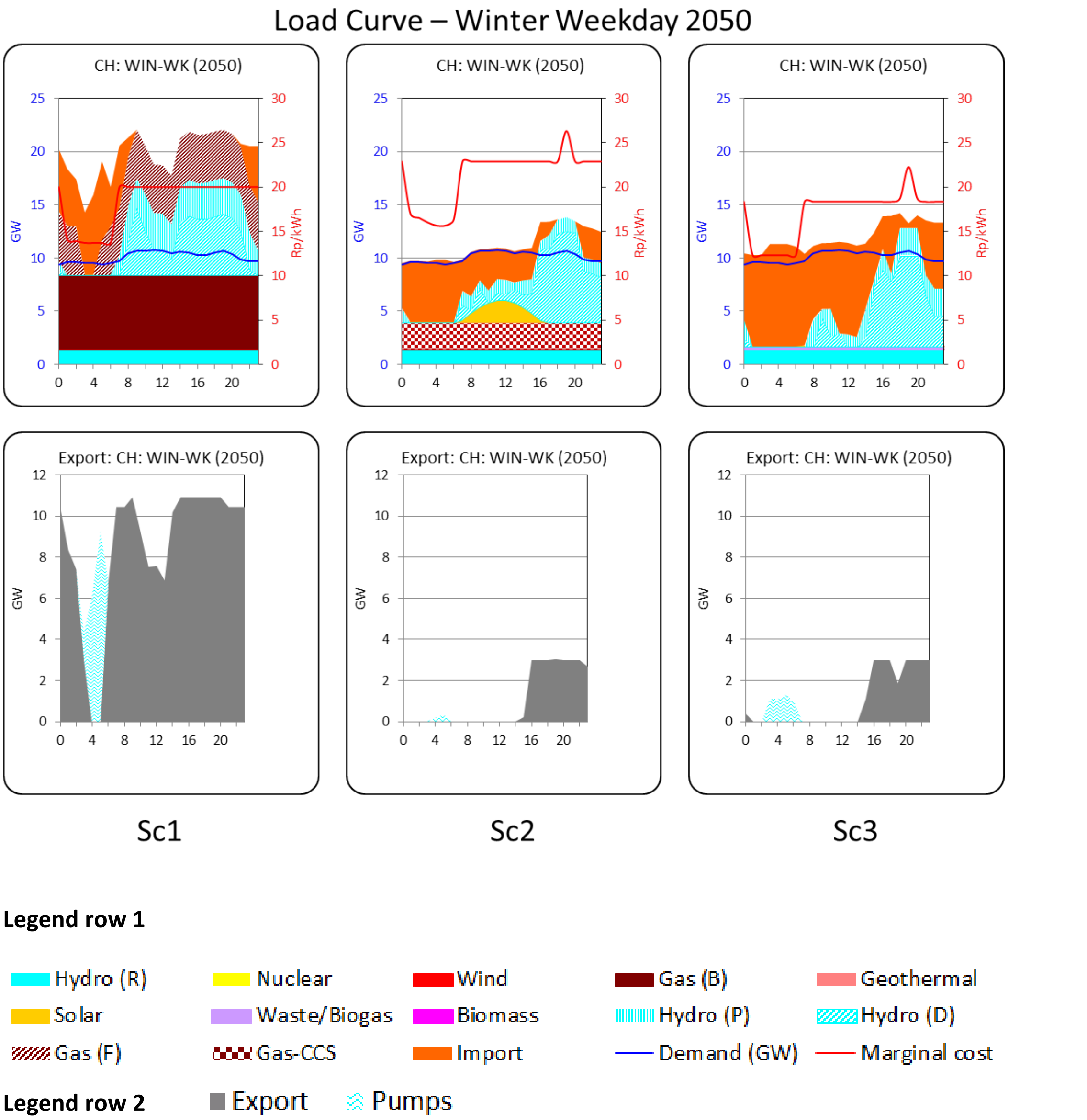


Figure 4-20: Electricity generation schedule of Switzerland on a winter weekday in 2050

In *Sc2*, due the CO_2 constraint, Switzerland does not have similar levels of base load capacities as for *Sc1*, with only around 39% of the demand covered by base load gas CCS plants and river hydro (vs. 84% in *Sc1*). There is a higher reliance on imported electricity throughout the day, with solar PV and dam/pumped hydro plants reducing the level of imports during peak hours (08:00 – 00:00). Exports in winter are greatly reduced in this scenario compared to *Sc1*. The source of the imported electricity and market for the exported electricity for *Sc2* is further elaborated in section 4.3.3.3.

In *Sc3*, in the absence of gas plants (as per scenario definition) and renewable technologies (due to high costs compared to imported electricity), electricity imports are required throughout the day, with only 16% of the demand covered by base-load river hydro plants. As observed with *Sc2*, flexible hydro plants are scheduled during peak hours to reduce imports at higher electricity prices.

While comparing the marginal costs in Figure 4-20, *Sc2* displays the highest marginal costs amongst the three scenarios. This is due to a combination of the CO_2 emissions cap which increases cost of imported electricity compared to *Sc1*, and the self-sufficiency constraint which forces investments in expensive gas CCS technology. The latter is inferred from insights obtained from *Sc3*. *Sc3* has the lowest marginal costs – even lower than the *Sc1* scenario which does not have any CO_2 emission constraints. This indicates that Switzerland has to pay a high cost for the gas based generation to fulfil the self-sufficiency constraint. Otherwise, cheaper import options are available elsewhere in the neighbouring countries.

4.3.3.3 Electricity trade – source of import and market for export

As will be explained in section 4.3.4, one of the main advantages of CROSSTEM over a single region electricity model is that the electricity trade is endogenous and based on marginal cost of generation. This means that in order to import electricity in one region, there has to be a surplus electricity generation in at least one of the other regions. Hence in CROSSTEM the source of electricity import and market for export can be traced to understand the underlying drivers. To illustrate this, Figure 4-21 shows electricity generation schedule on a winter weekday in 2050 for *Sc2,* for all five countries with their source of import and market for export. The top panel shows the electricity generation schedule while the middle and lower panels show countries from/to which electricity is imported/exported.

We start with the generation schedule for Switzerland, which has already been described above (see Figure 4-20). Electricity is imported almost throughout the day. The majority of the imports are coming from Germany, with minor supply from France, Italy and Austria during the early morning hours (00:00-07:00). Switzerland exports electricity during the evening hours (16:00-00.00) to Italy.

The German electricity schedule shows that there is indeed overproduction of electricity throughout the day from its large wind and thermal base-load capacity. This is further supplemented by solar PV during the day time, with flexible hydro dispatched during evening hours. Electricity is imported only for a few hours in the evening (18:00-20:00), with imports coming from France. Exports are primarily to Switzerland, Austria, France and the fringe (Other) regions.

In France, the demand is fully covered by a combination of nuclear, river hydro, coal CCS and waste/biogas based electricity generation. Solar PV and dam hydro complement these base-load plants, resulting in continuous exports throughout the day, primarily to Italy.

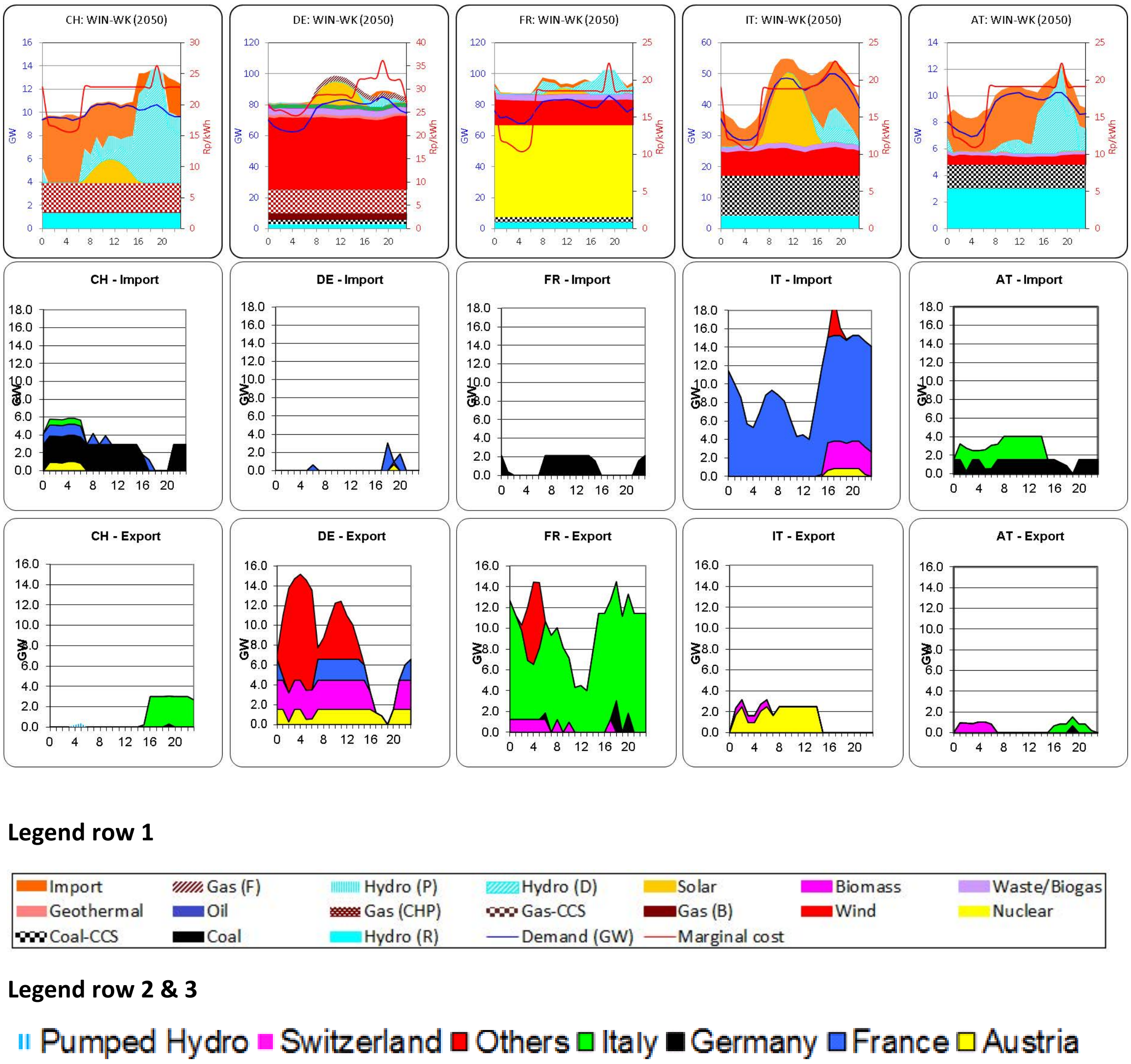


Figure 4-21: Electricity generation schedules on winter weekday 2050 (*Sc2*)

Italy has a high investment in solar PV due to its high availability factor in the region, which is supplemented by wind, coal CCS, waste/biogas and river hydro based generation. However, total supply from these sources is lower than the demand and therefore imports are required throughout the day. Most of the imports come from France. The output from solar PV is favourable to the steep increase in demand during daytime. In the evening (17:00-00:00), flexible hydro plants are scheduled to manage the second peak in demand. However, Italy still requires substantial imports to meet the evening peak demand and the imported electricity is supplied from France, Austria and Switzerland. Italy also imports more than its demand during 01:00-14:00 from France, which is eventually exported to Austria during the first half of the day (01:00-14:00).

Austria has a profile similar to Switzerland. Imports are happening throughout the day, coming mainly from Italy and Switzerland, with the flexible hydro plants dispatched during the evening hours to reduce imports at peak price hours.

Similar electricity generation schedules for the other scenarios, other seasons and other days of the week are given in Appendix B.

4.3.3.4 Cost of electricity supply

Figure 4-22 shows the annual undiscounted electricity system costs for Switzerland for the three scenarios. The costs are broken down to various cost components such as capital costs (annuities on investments), taxes (levy on nuclear spent fuel and CO_2), fixed and variable operation and maintenance costs, fuel costs and trade balances, which refer to net profits if negative or cost if positive from electricity import or export. The net system cost is also shown in Figure 4-22 (blue marker).

The electricity system cost increases from 2010 to 2050 in all three scenarios in line with the electricity-demand assumption. For *Sc1*, in the near to long term future (2020-2050) the main increase is in capital and fuel cost component due to the investment and operation of new natural gas power plants. The higher share of gas based generation (Figure 4-17) as well as increasing natural gas price assumptions increase the total cost of fuel in the energy system. The increasing CO_2 emissions (see Figure 4-25) also results in an increase in the taxes (CO_2 taxes). At the same time, the relatively high quantity of electricity trade (see Figure 4-20) generates surplus revenue. Nevertheless, the total system cost increases.

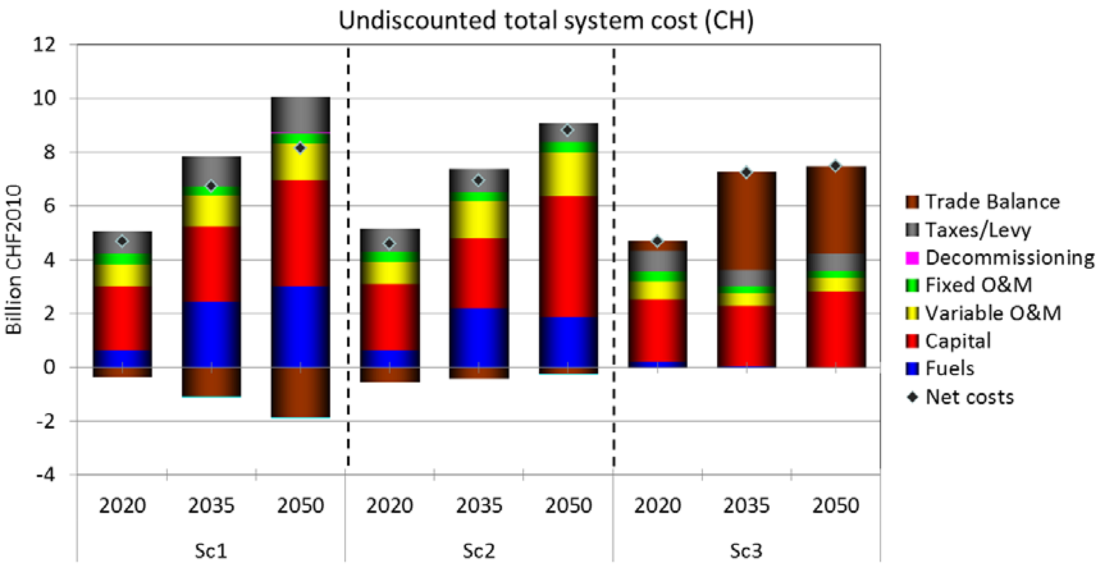


Figure 4-22: Undiscounted system costs (Switzerland)

In *Sc2*, the generation mix in the near term is similar to *Sc1* resulting in similar costs. By 2035 however, the 'total' cost is slightly lower in *Sc2* compared to the *Sc1* scenario. Relatively lower installed capacity (see Figure 4-18) in gas based generation results in a decrease in fuel costs, as well as CO_2 taxes. However, the level of the capital cost component (see Figure 4-23) is similar to the *Sc1* scenario, because *Sc2* requires capital intensive technologies like gas CCS plants, solar PV and wind turbines (Figure 4-18).

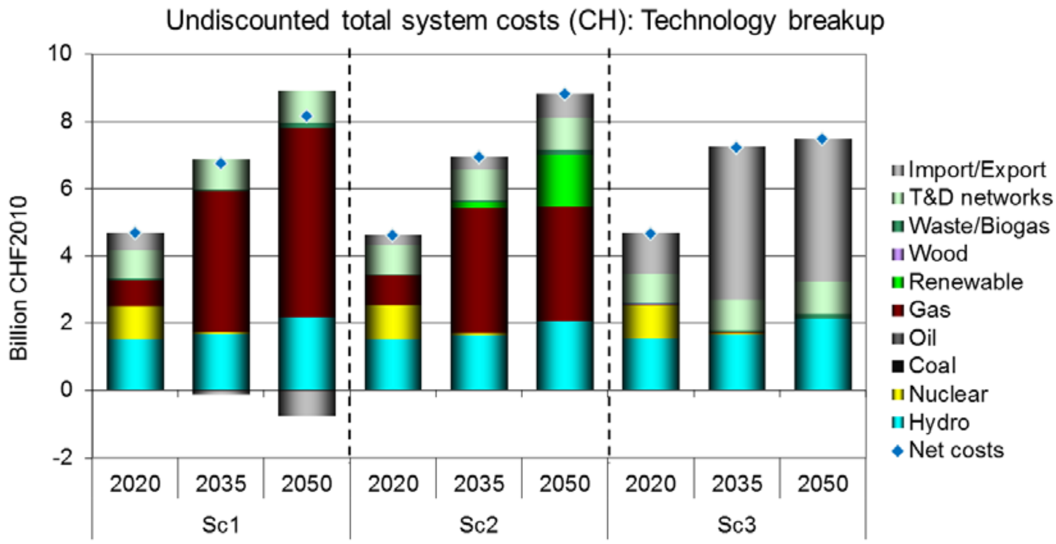


Figure 4-23: Undiscounted system costs (Switzerland): Technology breakup

By 2050, investments in renewables technologies (solar PV and wind) increase the capital costs further, but the fuel costs and CO_2 taxes reduce due to lower gas CCS based electricity generation (see Figure 4-18). Although the 'total' system costs are lower in *Sc2* compared to *Sc1* for years 2035 and 2050, the 'net' system cost (obtained by subtracting the surplus trade revenues from total system cost) is higher in *Sc2* due to lower trade revenue. This is because the electricity supply cost of Switzerland is expensive compared to other CROSSTEM countries in *Sc2*, making it less attractive for other countries to import from Switzerland, thereby reducing the trade revenue. Figure 4-24 shows the average cost of electricity *Sc2* and *Sc3* relative to Sc1, with the cost for *Sc2* around 8% higher in 2050 compared to *Sc1*.

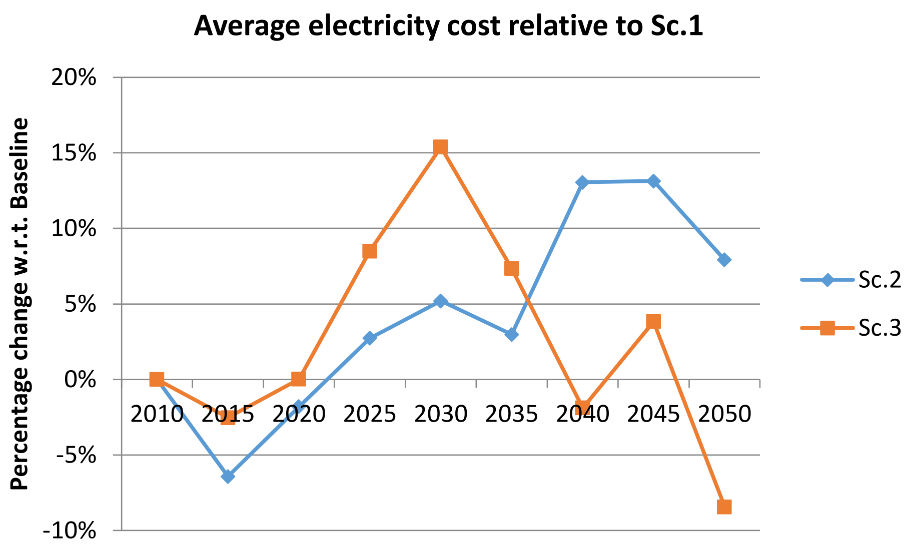


Figure 4-24: Average cost of electricity (Switzerland)

The *Sc3* scenario has the lowest system cost amongst the three scenarios. The cost of imported electricity (see trade balance in Figure 4-22) makes up the major share of the total system costs (27% of the total costs in 2020, 63% in 2035 and 57% in 2050), as imported electricity constitutes a major part of electricity supply in Switzerland due to the relaxation of the self-sufficiency constraint. In 2020, costs of import are still cheap giving *Sc3* the lowest net system costs and thus average electricity cost amongst the three scenarios (see Figure 4-24). As the CO_2 constraints become more stringent by 2035, cost of imported electricity becomes high due to capital intensive investments in renewable and CCS technologies in the neighbouring countries. By 2050, cost of electricity imports reduces further owing to lowering costs of renewables and CCS plants due to technology learning, thereby making *Sc3* the cheapest in terms of average costs by 2050 (costs decrease around 8% by 2050 compared to *Sc1*, Figure 4-24). It is worth noting that the system is optimized for the all five regions together, and the relaxed self-sufficiency constraint makes it feasible for Switzerland to import the cheap low carbon electricity.

4.3.3.5 CO_2 emission

Figure 4-25 shows the total CO_2 emissions from the five countries for all three scenarios. In the *Sc1* scenario, the total emission increases in the short term (till 2020) due to increased coal based electricity supply in Germany to replace the existing nuclear capacity. In the later years, the CO_2 tax becomes sufficiently high to make investment in renewables and CCS technologies cost-competitive, thereby reducing emissions as well. The figure also shows the extent to which each country reduces their CO_2 emissions to meet the emission targets in the low carbon scenarios. In *Sc2*, Switzerland still contributes to the total CO2 emissions, while there are no emissions from Switzerland in *Sc3* due to the restriction on investments in gas plants. This results in slightly higher emissions in Germany, due to higher investments in normal gas plants than in the more expensive gas CCS plants.

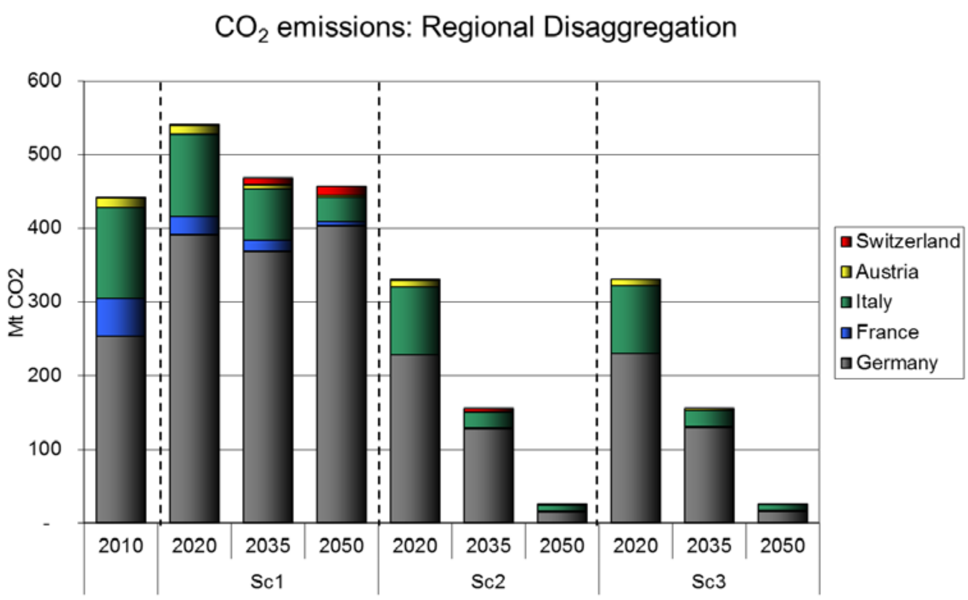


Figure 4-25: CO_2 emissions: Regional Disaggregation

4.3.4 Advantages of CROSSTEM over CROSSTEM-CH

This section highlights some of the strengths of a multi-region model like CROSSTEM with endogenous electricity trade, over a single region Swiss electricity model like STEM-E or CROSSTEM-CH with exogenous boundary conditions on electricity trade. To illustrate the differences, the *Sc1* scenario of CROSSTEM is compared with the *'Sc1* equivalent' *Baseline* scenario from the coupled framework (described in section 4.2.2.2), as they have identical electricity demand and supply options for Switzerland. The results are compared with respect to the electricity generation mix and generation schedules to understand the underlying drivers.

4.3.4.1 Electricity generation mix

Figure 4-26 shows the electricity generation mix for Switzerland from both models. Although the fuel and technology mix in both models are similar in the near term (2020), there are significant differences in the long run. In 2035 for instance, both models choose around 28 TWh of gas-based electricity generation. However, in the *Baseline* scenario of CROSSTEM-CH, around 80% of the gas-based electricity generation originates from base-load type plants, whereas in the CROSSTEM only around 45% is generated by base-load plants, while rest comes from flexible gas plants. As flexible gas plants are assumed to be less efficient than their base-load counterparts, this increases the fuel consumption and hence cost of electricity.

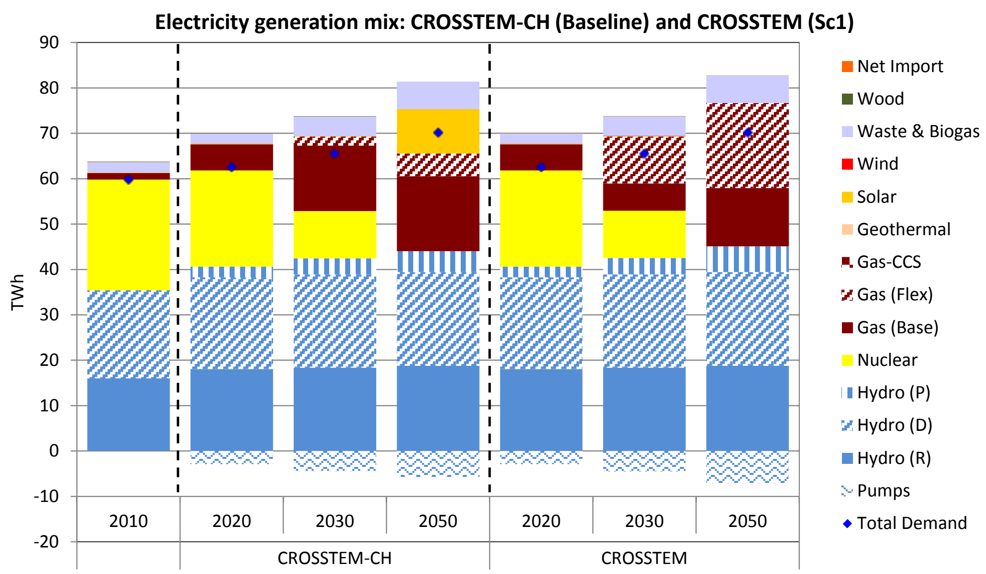


Figure 4-26: Swiss electricity supply mix: CROSSTEM-CH vs CROSSTEM

An even larger difference is observed in the year 2050 in terms of the electricity supply. While CROSSTEM-CH chooses a considerable quantity of solar PV in the generation mix, no solar PV investments are made in CROSSTEM. Moreover, as seen in 2035, most of the gas plants in CROSSTEM-CH are base-load type (80%), whereas the major share of gas plants in CROSSTEM comes from flexible gas plants (54%). There are two main reasons for this difference in technology choice: (a) the “load dumping” phenomenon in the single region model, which is minimised in CROSSTEM, and (b) variations in the exogenous import/export prices assumption in CROSSTEM-CH.

“Load dumping” is a term used to describe the phenomenon of dumping excess electricity to neighbouring countries without any knowledge of their markets. In a single region model like CROSSTEM-CH, the electricity imports/exports are exogenously defined. Although there are bounds on total trade volume as well as market share constraints to reflect historical trading patterns with neighbouring countries, there is no restriction on the timing of the imports or exports. This means that imported electricity is assumed to be available whenever there is a demand and electricity can be exported whenever there is an excess generation[32]. In reality, neither of these conditions are true, but it is a common compromise made in single regions models (Densing et al., 2014). This issue was one of the main motivations for developing CROSSTEM. “Load dumping” is partly addressed in the CROSSTEM model, wherein electricity can be imported only when there is excess generation in the surrounding countries. Similarly, electricity exports are only possible when there is a market (i.e. demand) in the surrounding countries. This is why in the *Baseline* scenario of CROSSTEM-CH, most of the gas-based generation is produced from base-load plants, which are more efficient (and hence cheaper) than flexible gas plants. In contrast, Switzerland in CROSSTEM has to invest more in flexible gas plants to be able to optimize the trading patterns with

[32] It should be noted that “load dumping” in single-region models could be mitigated by additional modelling of fringe regions. For example, a generation and consumption profile could be introduced for fringe regions, which prevents it from acting as a flexible electricity generation process (as well as flexible consumption processes). The definition of such exogenous generation and consumption profiles does not, however, reflect future variations in electricity demand and supply patterns in the fringe regions.

the real market conditions of the neighbouring counties (and *vice versa*).

The second driver is the assumption on electricity trade price. Figure 4-27 shows the exogenously given electricity import/export price assumptions[33] in the CROSSTEM-CH model versus the marginal cost of electricity in the surrounding countries of Switzerland obtained from CROSSTEM, for the year 2050. As observed in the figure, the exogenous import/export price assumptions in CROSSTEM-CH are relatively higher in all time slices compared to CROSSTEM except for winter weekdays[34]. This implies that exporting electricity in summer or spring is as attractive for CROSSTEM-CH as in the winter season, since the model fully ignores the source of imported electricity and/or the market for exported electricity. The high electricity trade price assumption during the peak hours in CROSSTEM-CH across different seasons enables solar PV to become an attractive option to generate excess electricity, which is then exported at those peak hours assuming that there is a market to export to.

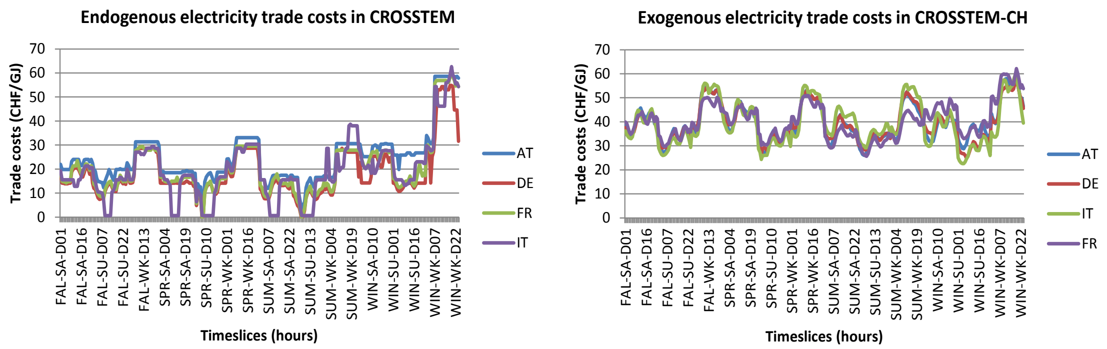


Figure 4-27: Electricity import/export costs for Switzerland - CROSSTEM (endogenous) vs CROSSTEM-CH (exogenous)

In CROSSTEM, electricity prices in winter are much higher than in the other seasons reflecting high demand across all regions in winter. The CROSSTEM model indicates that there is no market in neighbouring countries to import excess electricity generated from solar PV in Switzerland, as these countries also invest in solar PV, and have better

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[33] In hourly price assumption is estimated based on annual cost of electricity supply from the ADAM model. The methodology is explained in (Kannan/Turton 2011).

[34] It should be noted that the import prices adopted from the ADAM model were for a stringent climate scenario, resulting in high import prices (Kannan et al., 2011)

conditions for it (for example higher solar availabilities in Italy). Instead, the model finds it better to invest in flexible gas based generation in Switzerland to export electricity during winter periods, and thereby generate higher trade revenues see section 4.3.4.2).

A similar observation can be drawn from the *NoGAS* scenario for CROSSTEM-CH and the '*NoGAS* scenario equivalent' *Sc3* for CROSSTEM. The higher electricity import costs assumed in the CROSSTEM-CH model result in higher investments in domestic renewable technologies and thereby minimizing the net electricity imports. On the other hand, cheaper electricity generation costs in neighbouring regions favours electricity imports for Switzerland in the CROSSTEM model.

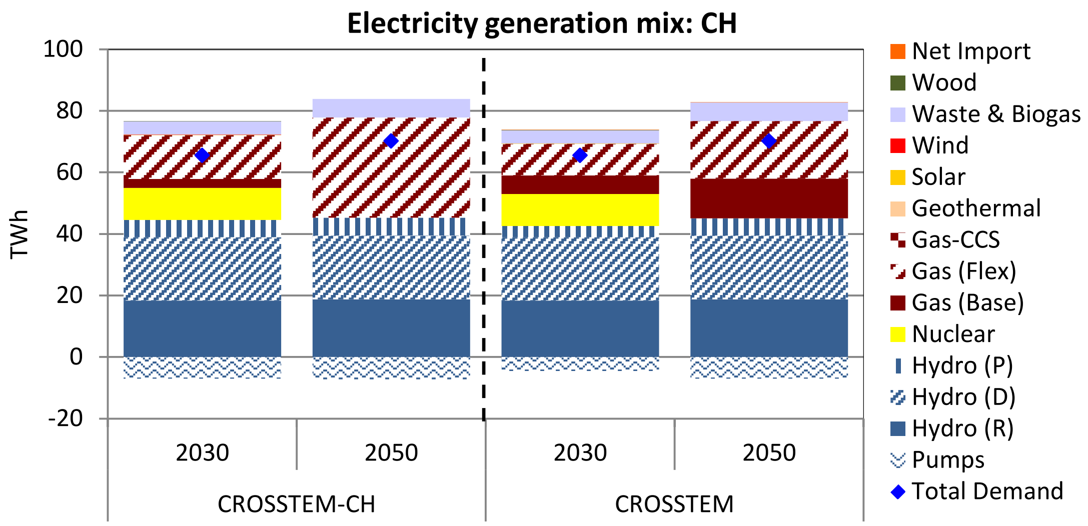


Figure 4-28: Swiss electricity supply mix CROSSTEM-CH vs CROSSTEM (with same electricity trade costs in both models)

When the CROSSTEM-CH model was rerun using the marginal electricity generation costs of neighbouring countries from the *Sc1* scenario of CROSSTEM for exogenous electricity trade prices, the resulting electricity generation mix given by CROSSTEM-CH resembled that of the *Sc1* scenario, as shown in Figure 4-28. No longer are there any investments in solar PV based electricity generation in CROSSTEM-CH, due to the lower summer electricity trade cost assumption. However, trade volumes and trade patterns in the CROSSTEM-CH model are still very different compared CROSSTEM, as fringe trade is modelled as a flexible generation and consumption process in

CROSSTEM-CH. Electricity trade in CROSSTEM-CH aims to maximise trade revenue by exporting electricity during peak price hours (especially in winter), which in turn resulted in the high penetration of load following flexible gas plants in CROSSTEM-CH compared to CROSSTEM.

4.3.4.2 Electricity generation schedule

Figure 4-29 shows the differences in the electricity generation schedules in Switzerland between the two models on a summer (Figure 4-29 a) and winter (Figure 4-29 b) weekday in 2050. As mentioned before, the electricity import/export profiles in CROSSTEM-CH are merely driven by the exogenous trade price assumptions, whereas in CROSSTEM, the trade becomes endogenous, which means that import/export patterns are highly dependant on supply options and demand in neighbouring countries (Figure 4-21).

In the summer, CROSSTEM-CH dispatches all the flexible hydro from 08:00-16:00, supplementing the solar PV generation to export maximum electricity during these peak hours, with electricity imports required to meet the demand in early morning and late evenings. In CROSSTEM on the other hand, most of the imports occur during the early morning hours which is simultaneously also exported, with no export during the daytime hours 08:00-16:00, as there is no supply shortfall in neighbouring regions during those hours. Dam/pumped hydro and flexible gas plants are scheduled during the evening hours to be exported to Italy from 16:00-00:00 (see Figure B5 in Appendix B for details on sources of electricity imports and markets for electricity exports in the CROSSTEM *Sc1* scenario).

In winter (Figure 4-29 b), electricity is imported almost throughout the day in CROSSTEM-CH, except for the two peak hours between 09:00-12:00 and 17:00-19:00, when electricity prices are assumed to be high. All the flexible generation is scheduled for these hours, thereby maximizing export trade revenue. In CROSSTEM, marginal costs of electricity in winter are very high, which makes it very attractive for Switzerland to export electricity. Hence, full capacity of the installed gas plants is scheduled in winter, supplemented by dam and pumped hydro. As mentioned before, this import/export pattern for Switzerland in CROSSTEM is only possible because of matching conditions in the surrounding countries (see Figure B6 in Appendix B).

Hence, the profiles from CROSSTEM are more consistent than those obtained from CROSSTEM-CH, which would have similar import/export patterns for all scenarios (section 4.2.2.2.3).

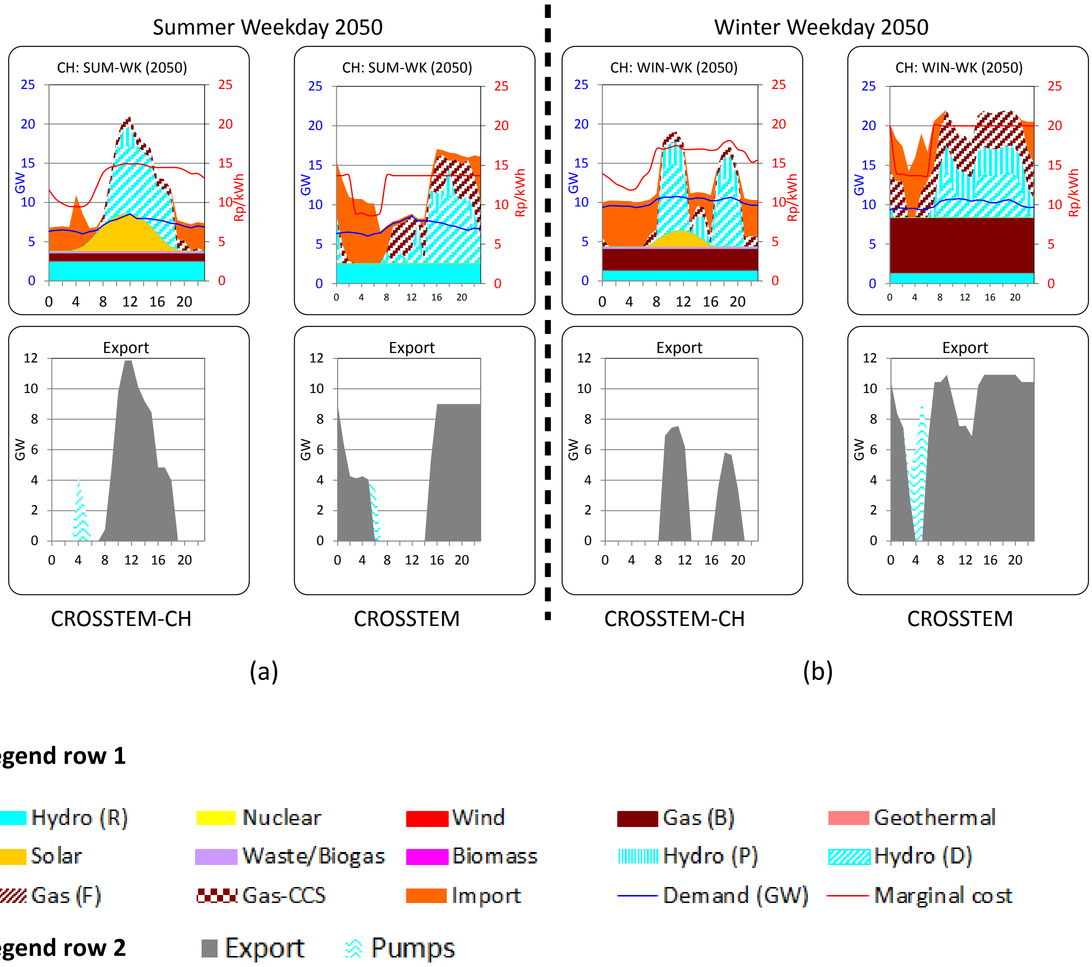


Figure 4-29: Electricity generation schedules - CROSSTEM-CH vs CROSSTEM

4.4 Conclusions

The ELECTRA-CH framework successfully coupled a top-down CGE model with a bottom-up technology model. The representative scenarios analysed with the framework demonstrated the capabilities of the coupled model, and highlighted its superiority over the respective stand-alone versions. The new framework combines the best of bottom-up and top-down components, greatly improving the understanding of supply and demand interactions. The main impact of coupling the CROSSTEM-CH model with the CGE model was the endogenization of the electricity demand. The ELECTRA-CH framework introduces implicit demand elasticities in the previously inelastic electricity demands of the bottom up model.

The limited set of scenarios presented in section 4.3.3 with the assumed set of boundary conditions shed novel insights on the development of Swiss electricity system in conjunction with developments in neighbouring countries, which had not been possible with the existing single region models of Switzerland. Comparisons of CROSSTEM with CROSSTEM-CH showed that by not representing the electricity markets of neighbouring countries, single region models such as CROSSTEM-CH overestimated the penetration of renewable technologies such as solar PV, and underestimated the flexible generation and storage requirements needed to balance the electricity system. By simultaneously optimising both electricity generation and electricity trade, CROSSTEM addressed the uncertainties associated with electricity trade volumes and costs by endogenising the electricity trade of Switzerland with its neighbouring countries to find the least cost solution. The analysis proved that the multi-region model is a very powerful tool to explore different boundary conditions of the neighbouring countries to generate insights for policy decisions.

5 ALTERNATIVE LOW-CARBON ELECTRICITY PATHWAYS UNDER A NUCLEAR PHASE-OUT SCENARIO

The analysis presented in Chapter 4 was based on the ELECTRA project, and many of the assumptions used in the project were defined by the client or with data until the year 2012. Some of these assumptions, such as fuel prices from 2010, are outdated and needed to be revised. This chapter presents a set of scenarios with an updated version of CROSSTEM. The main improvements include updates of cost numbers for certain technologies, international energy prices, CCS storage potentials, interconnector costs etc. The analysis in this chapter focusses on the nuclear phase-out policies of Switzerland and its surrounding countries, as well as establishing a decarbonised power sector by 2050. A series of parametric sensitivity analyses are also included to quantify policies such as self-sufficiency in electricity generation, impact of increasing electrification of transport and heat sectors etc. The chapter concludes with a discussion on some of the limitations in CROSSTEM, and possible solutions to overcome these shortcomings. This chapter has been published as a journal paper in Applied Energy (Pattupara & Kannan, 2016).

5.1 Introduction

A wind of change is currently sweeping through European energy policies. The “nuclear renaissance” that was expected to provide a low carbon alternative source of electricity in the medium- to long term future, came to a shuddering halt in many European countries after the Fukushima nuclear accident (Wittneben, 2012). Germany, which until March 2011 produced a quarter of its electricity from nuclear energy, immediately shut down eight of its oldest reactors (around 8.3 GW of 20.3 GW installed nuclear capacity), with the remaining nine reactors to be shut down by 2023 (World Nuclear Association, 2014b). Switzerland, which has around 36% nuclear based electricity generation, originally envisaged to replace some of its existing nuclear fleet with new nuclear plants (ENSI, 2010). However, on the 25th of May 2011, the federal government decided to gradually phase-out nuclear energy as part of its new energy strategy to 2050 (FASC, 2011). Italy intended to produce 25% of its electricity supply from nuclear power by 2030, but decided to continue with its nuclear moratorium after a referendum in June 2011 (World Nuclear Association, 2014c). France, a traditional nuclear powerhouse with over 75% nuclear based electricity generation, also faces political problems in terms of expanding or replacing their existing nuclear fleet (Maïzi et al., 2014). The current government proposed to reduce the share of nuclear to 50% of the total electricity generation by 2025 (ÉLYSÉE, 2012).

While the decision to abstain from nuclear power is not very drastic in itself, discussions continue on alternative sources of electricity supply. For instance, Germany has been substituting nuclear generation with coal-fired electricity generation. More than half (52%) of Germany’s electricity generation was from coal in 2013, compared to 43% in 2010. This in turn has increased Germany’s CO_2 emissions despite the country’s efforts to support renewable development (World Nuclear Association, 2014b). Italy is heavily dependent on fossil fuel generation (46% from natural gas, 16% from coal, 9% from oil), and is also Europe’s largest net importer of electricity (about 15% of total demand) (World Nuclear Association, 2014c). Switzerland foresees a combination of natural gas, renewables and/or electricity imports as possible substitutes for outgoing nuclear power plants (PROGNOS AG, 2012).

The European Union (EU) emphasises a low-carbon energy pathway for the long-term future and the EU Roadmaps foresee an almost complete decarbonisation of the electricity sector by 2050 (European Commission, 2011). Phasing-out of nuclear in the aforementioned countries could undermine their policy objectives on climate change mitigation. These conflicting developments pose considerable technological and economic challenges. Hence, it is important to explore non-nuclear alternative sources of electricity supply and understand their implications in a wider context.

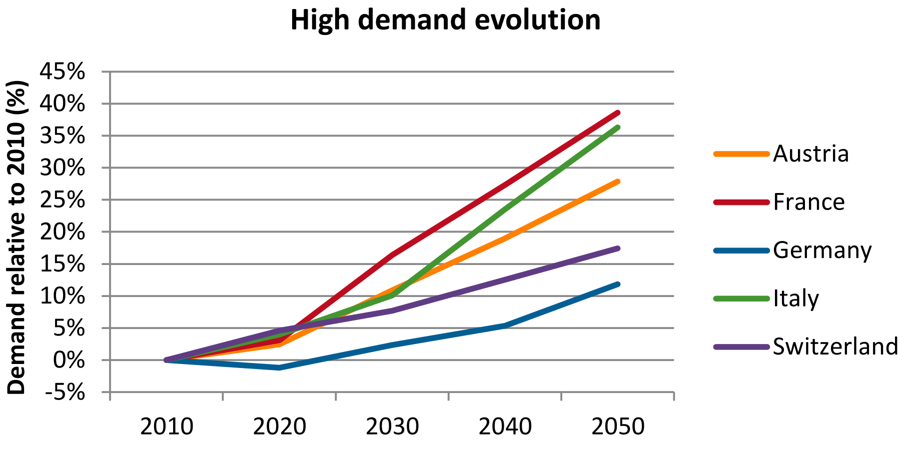
An updated version of the CROSSTEM model is used for the current analysis. Although the overall model structure remains the same as described in Chapter 3, some of the input data assumptions have been revised from what were used for the ELECTRA project described in chapter 4. Section 5.2 of this chapter describes the major model updates. This is followed by a brief overview of the scenarios used for the analysis. The chapter ends with a discussion of the results and conclusions.

5.2 Model updates

Compared to the analysis presented in Chapter 4, key input data assumptions such as electricity demand, CCS storage potentials, international energy prices, price of electricity import/export with fringe countries, and electricity interconnector costs are updated. They are discussed in the following subsections.

5.2.1 Electricity demand

The electricity demand used for the analysis presented in this chapter is shown Figure 5-1. Electricity demands for the surrounding countries are taken from the reference scenario of the EU Trends to 2050 study (European Commission, 2013), which incorporates all binding targets set out in the EU legislation regarding development of renewable energy and reductions of greenhouse gas (GHG) emissions, as well as the legislated energy efficiency measures. The electricity demand for Switzerland is unchanged from Chapter 4, and is taken from the ”Weiter Wie Bisher” (WWB) scenario of the Swiss Energy Strategy 2050 (PROGNOS AG, 2012). The demands from the EU trends to 2050 study are higher than the demand assumptions used in Chapter 4. The total electricity demand for all five countries combined increases by 27 % between 2010 and 2050 in the current analysis. In comparison, the total corresponding electricity demand increase in Chapter 4 was only by 3% between 2010 and 2050.



Source: (European Commission, 2013; PROGNOS AG, 2012)

Figure 5-1: Electricity demand evolution in CROSSTEM

It should be noted that demand responses and electricity efficiency improvements are not explicitly represented, with demand side measures expected to be captured in the assumed electricity demand growth rate. An alternative scenario with a low demand assumption for Switzerland will also be analysed in section 5.4.4.

5.2.2 CCS potentials

The scenarios described in this chapter use the medium CO_2 storage potentials described in section 3.4.8 of chapter 3, compared to the high CCS potentials used for the analysis in chapter 4. The medium storage potentials limit the CO2 storage to hydrocarbon fields. This assumption is based on the fact the geology of hydrocarbon reservoirs is generally well understood, and current CCS pilot projects mainly focus on such oil and gas reservoirs (Carbon Capture and Storage Association, 2015).

5.2.3 Interconnectors

In the ELECTRA project, universal interconnector costs were applied for all regions irrespective of the transmission networks within each region. As CROSSTEM is a spatially aggregated model, an ad-hoc approach was developed to incorporate transmission distances into the interconnector costs. This approach is described in section 3.4.6 in chapter 3.

5.2.4 Solar and Wind growth constraints

In order to avoid exponential growth in deployment of solar PV or wind based electricity generation, an annual growth constraint on total installed capacity was introduced for these technologies. This constraint is based on historical capacity expansion rates of these technologies from the last decade in Germany (Bundesministerium für Wirtschaft und Energie, 2011). For solar PV technology, this growth constraint equates to 8 GW per year per country, while deployment rate of wind technology is capped at 12 GW per year per country. In addition, the expansion of the intermittent renewables is limited by their technical potential in each period (see Table 3-6).

5.2.5 Exogenous electricity trade prices

For the ELECTRA project scenarios, the electricity import / export prices with the fringe regions were adopted from the ADAM project (Frauenhofer, 2010; Kannan et al., 2012). All the scenarios analysed in Chapter 4 use a high electricity price assumption for the exogenous electricity imports and exports, as shown in Table 5-1.

Table 5-1: Exogenous electricity trade prices in CROSSTEM

Import/Export prices (CHF/GJ)	2010	2030	2050
ADAM	15.6	44.8	43.7
EUSTEM – Low	15.6	22.6	21.5
EUSTEM – High	15.6	33.2	41.8

For the analysis presented in this chapter, exogenous electricity prices for fringe regions are taken from the marginal electricity price of European Swiss TIMES Electricity (EUSTEM) model (described in chapter 6). Two sets of electricity prices are implemented based on two sets of boundary conditions in EUSTEM. Scenarios with no climate change mitigation targets (see scenarios 5.3.1 and 5.3.3) use the EUSTEM-low (see Table 5-1) prices for exogenous electricity. For the climate mitigation scenario (scenario 5.3.2), EUSTEM-High prices are used for the exogenous electricity trade prices. The prices are obtained from a reference and climate target scenario run in EUSTEM.

5.3 Scenario Description

Three scenarios are analysed in this chapter, to generate insights into the implications of nuclear phase-out policies and the decarbonisation of the power sector.

5.3.1 Nuclear phase-out policy Scenario - (*NoNUC*)

In this scenario, the current nuclear policies of the five countries are implemented. This implies that Switzerland will not invest in new nuclear plants, with the existing plants operating until the end of their 50-year lifetime. Germany will phase-out all nuclear capacity by 2023. France will reduce the share of nuclear generation from the current level of 75% to 50% of total electricity generation by 2025 and beyond. Austria and Italy do not invest in new nuclear plants.

In addition to the nuclear policies, EU 20-20-20 targets (European Commission, 2007) are adapted and applied to all five countries. As the EU 20-20-20 targets are defined for the entire energy system, the targets have been adjusted for the electricity sector in this study. Hence, CO_2 emissions from the electricity sector of the five countries together are to be reduced by 20% from 1990 levels by 2020 and beyond. In addition, at-least 20% of the total electricity demand is to be met by new renewable (non-hydro) based electricity generation. The last part of the 20-20-20 targets envisages a reduction in energy demand by 20% via various demand response measures. However, as mentioned before, demand side management is not included in this model.

5.3.2 Climate Target Scenario - (*CO2*)

This scenario aims to decarbonise the power sector while retaining nuclear policy assumptions from the ***NoNUC*** scenario. The CO_2 reduction pathway is chosen in accordance with the European Union’s low-carbon roadmap (European Commission, 2011), which specifies a CO_2 reduction of 61% by 2030, and 95% by 2050 compared to 1990 levels. This CO_2 cap is applied across all five countries together and not on an individual country level. A variant of this scenario with CO_2 emission caps applied at national levels (***CO2-NatCap***) will also be presented in the discussions.

5.3.3 Least Cost Scenario - (*Least Cost*)

The aim of this scenario is to have a baseline to compare the technological and economic implications of nuclear phase-out and climate change mitigation goals. This scenario is a least-cost scenario, and shows the electricity mix when there are no technological constraints. Thus, in this scenario, neither nuclear phase-out policies nor decarbonisation policies are implemented; countries with an existing nuclear fleet (i.e., France, Germany and Switzerland) have the option to build new nuclear plants up to their 2010 nuclear generation levels. All other scenario assumptions, including the EU 20-20-20 targets up until 2050, remain unchanged from the ***NoNUC*** scenario.

5.4 Results

This section presents some of the key results obtained from the scenario analysis. The annual electricity generation mix and installed capacity, the hourly generation schedule, international electricity trade patterns and costs of electricity supply are discussed in the following subsections.

5.4.1 Electricity generation mix

Figure 5-2 shows the electricity generation mix of Switzerland for the years 2020, 2030 and 2050 for the three scenarios. The blue markers in the figure denote the electricity demand, which remains unchanged across all three scenarios. The electricity generation is higher than the demand to account for charging storage systems (such as pumped hydro storage) as well as for transmission and distribution losses.

Based on the input assumptions regarding technology costs, the immediate observation is the presence of dam and run-of-river hydro plants, which have a constant share of more than 50% of the total generation in all three scenarios. In the ***Least Cost*** scenario, nuclear power, together with electricity imports and flexible gas-based generation complete the generation mix for Switzerland. Electricity import accounts for 7-9% of the demand between 2020 and 2050. Developments in neighbouring countries play a major role in deciding whether Switzerland has to import or export electricity. This is illustrated in Figure 5-4, which shows the relative contributions of various technologies to the electricity supply mix of the five countries in the year 2050. In the ***Least Cost*** scenario, electricity supply from neighbouring countries, namely France and Germany, provide cheaper sources of electricity, which is imported by Switzerland. The imported electricity is generated mainly from nuclear, coal and wind, which are relatively cheap compared to domestic options within Switzerland like renewable energy or natural gas-based generation. Nevertheless, the Swiss system invests around 1.1 GW of flexible gas-based capacity (see Figure 5-3) in 2050 which, along with dam and pumped hydro plants, adds flexibility to the Swiss electricity system. The flexibility of the Swiss energy system facilitates electricity trade with neighbouring counties, through which it generates trade revenue by scheduling electricity exports during peak hours.

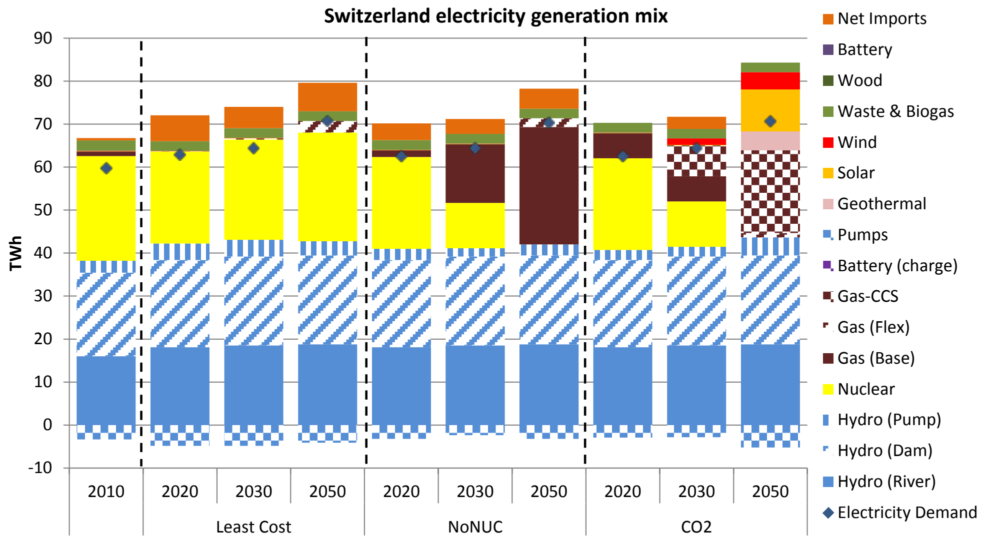


Figure 5-2: Switzerland generation mix

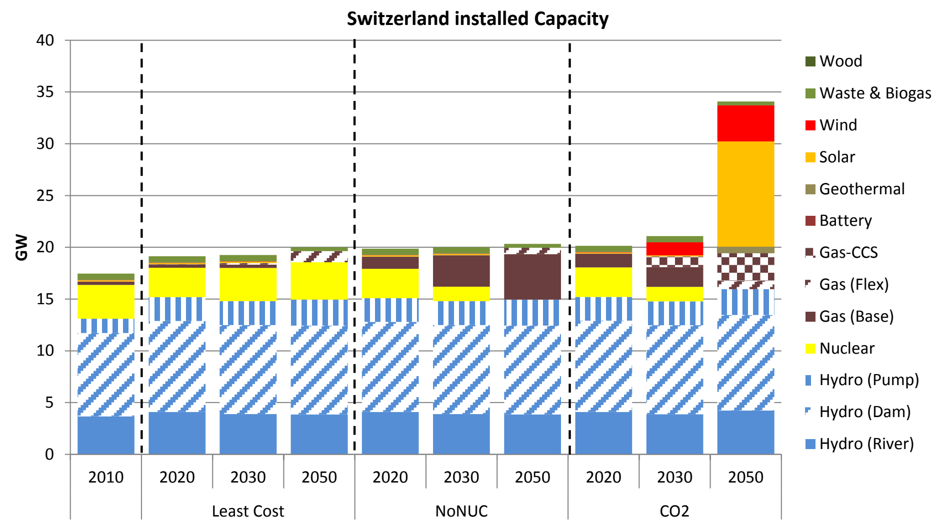


Figure 5-3: Switzerland installed capacity

In the nuclear phase-out scenario (***NoNUC***), nuclear plants in Switzerland are gradually replaced by gas-based generation, which is the least-cost option in the absence of climate change mitigation targets (and because investment in coal power is not considered for Switzerland). By 2020, around 2% of the total generation is from gas plants, which increases to 19% by 2030 and 35% by 2050. Compared to the ***Least Cos*** scenario the net level of imported electricity in 2050 is reduced to approximately 6% of the total demand in ***NoNUC*** versus 9% in ***Least Cost***. This is due to higher electricity generation costs in France and Germany as the result of their nuclear phase-out policy.

In the decarbonization scenario (***CO2***), gas-based electricity generation already accounts for 8% of total generation by 2020 in Switzerland, replacing nuclear power as well as the imported electricity seen in ***Least Cost*** and ***NoNUC*** scenarios. In the neighbouring countries, stringent CO_2 reduction policies force higher investments in natural gas plants instead of cheaper coal plants, which results in higher electricity generation costs. This makes electricity imports less attractive for Switzerland in ***CO2*** compared to other scenarios. By 2030, CCS technologies enter the market and provide a source of baseload low-carbon electricity. Gas CCS plants account for around 10% of the Swiss total generation in 2030, while baseload gas plants without CCS still retain 8% of the total generation mix. There is some investment in wind technology (1.3 GW by 2030) which is more cost effective than solar PV in the medium-term due to higher availability factors, particularly in winter. Switzerland still imports around 4% of the demand in 2030 due to the presence of cheaper coal CCS and wind-based alternatives in neighbouring countries (see Figure 5-4). By 2050, the share of new renewable-based generation in Switzerland increases to 25% of the total supply (5% from wind, 12% from solar PV and 8% from other renewables such as geothermal, biomass and waste). Gas CCS plants contribute to 23% of the total supply.

Switzerland generates surplus electricity and becomes a net electricity exporter by 2050 in the ***CO2*** scenario. The fact that Switzerland becomes a net exporter implies that one or more of the other regions either; (i) have a shortage in domestic supply and require electricity imports, or (ii) the domestic electricity generation costs are higher than the cost of imported electricity, which results in the neighbouring countries preferring imports from Switzerland. From Figure 5-4, it can be observed that Germany and Italy are net importers of electricity in ***CO2***. The reason for net imports in Italy is not due to resource constraints, as Italy could generate more electricity domestically for the same CO_2 emissions by replacing coal CCS with gas CCS technologies if required. However, instead of building more domestic baseload generation, Italy prefers to import electricity during off-peak hours, as explained in section 5.4.2. On the other hand, Germany requires electricity imports as it exhausts the assumed renewable and CCS storage potentials (see Table 3-6 and Figure 3-18 in chapter 3). Hence, investments in gas CCS plants are made in Switzerland, Austria and France which, besides supplying to their domestic demand, also serve as a source of imported electricity for Germany. The reason why this investment is distributed among the three regions instead of any single country[35] is attributed to the interconnector capacities between the regions, and is better understood by analysing the electricity generation schedule in the different countries as described in the next section.

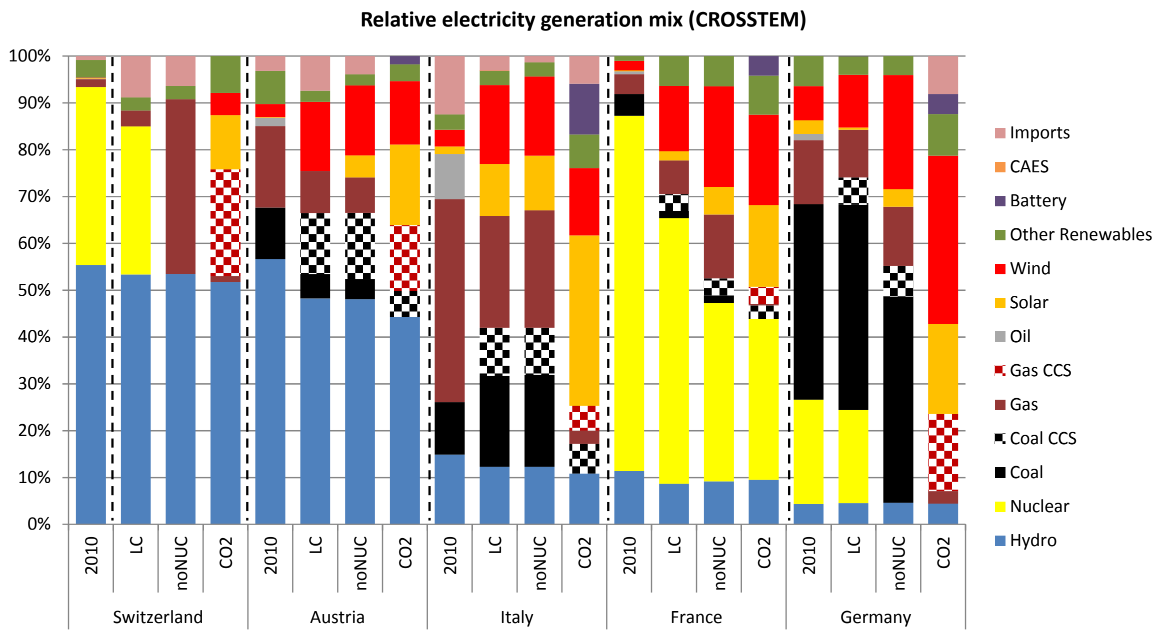


Figure 5-4: Relative generation mix (All regions)

[35] For example, generation from coal CCS plants in France or Austria could be replaced by gas CCS plants to increase electricity production for the same emissions.

5.4.2 Generation Schedule

A key feature of CROSSTEM is its hourly time resolution. In the following subsections, the hourly electricity supply and electricity trade patterns of the five countries are illustrated for the ***CO2*** scenario. Among the four seasons and three types of days (weekday, Saturday and Sunday), the generation schedule of an average summer weekday in 2050 is represented in Figure 5-5.

The first row in Figure 5-5 (series i.) illustrates the electricity demand (blue line) and generation schedule of different technologies. The red line shown in the generation mix diagrams (series i.) is the marginal cost of electricity in Rp/kWh (right hand side axis). Any generation above the demand line is either exported or stored via pump hydro/battery storage. The orange shades depict the imports, which are broken down by countries in the second row graphs. The second and third rows (series ii. and iii. in Figure 5-5) show the electricity import and export patterns, respectively, with the legend displayed at the bottom of the figure.

The second column (column b) in Figure 5-5 shows the electricity generation, import and export schedule of Switzerland. Of the total installed base load capacity of 8.7 GW (see Figure 5-3), around 5GW of baseload generation from run-of-river hydro, gas CCS and geothermal power is scheduled in the summer, complemented by a small fraction of wind power which serves as a sort of pseudo baseload generation. The total supplies from these plants are insufficient to cover even the lowest demand that occurs at 5.00.

Flexible hydro plants are scheduled during the early morning and evening hours, with surplus generation exported to Germany and Italy (Figure 5-5 ii.b). The demand during the daytime (8:00 to 16:00) is covered by solar PV generation, creating excess electricity supply throughout the day. Nevertheless, around 2 GW of electricity is imported during the peak hour 12:00, which comes from the solar PV output in Italy. A part of this imported electricity from Italy, combined with excessive generation in Switzerland, is exported to Germany and the remaining electricity (0.5 GW) is stored via pumped hydro storage systems in Switzerland.

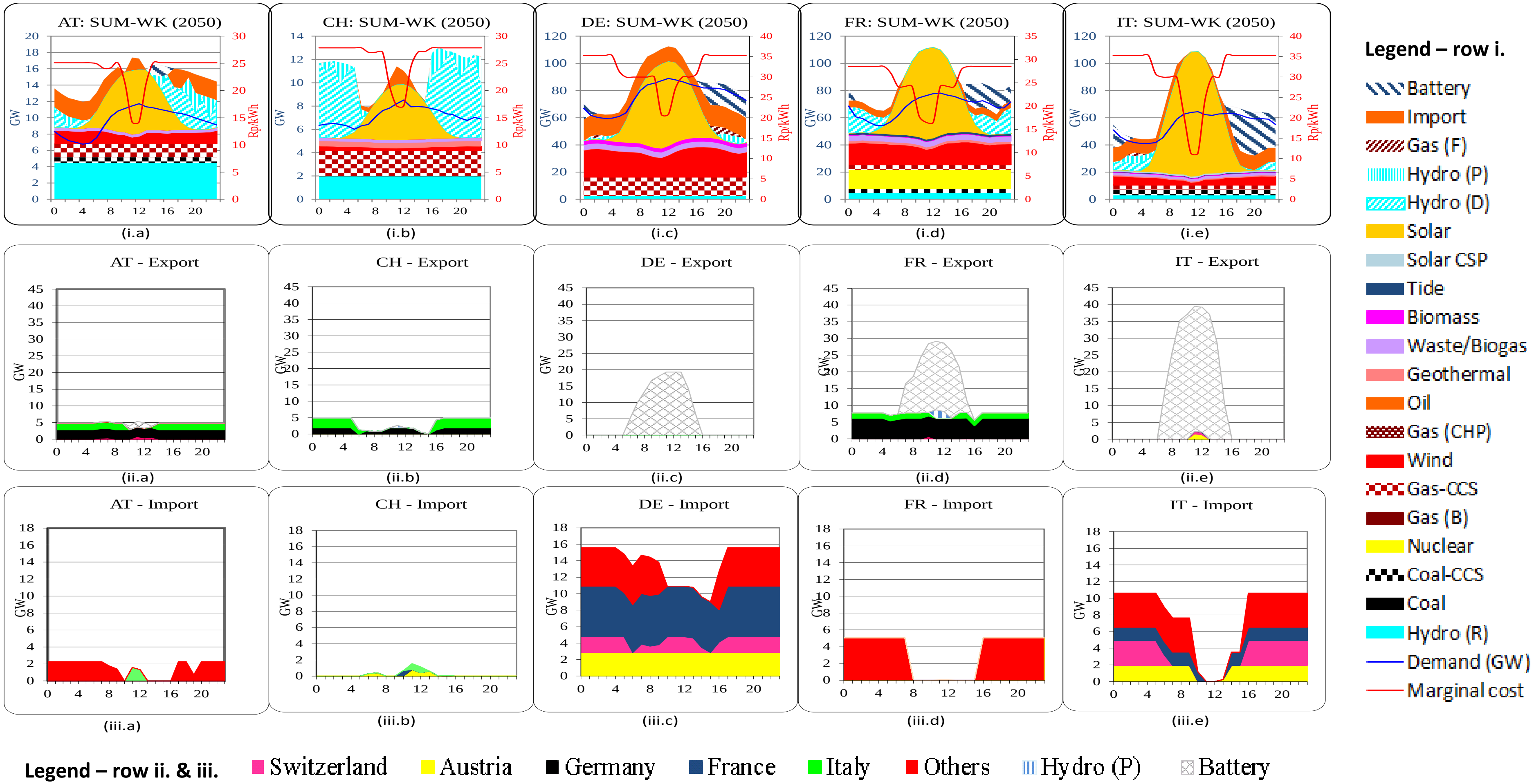


Figure 5-5: Generation schedule - summer weekday 2050 (*CO2*)

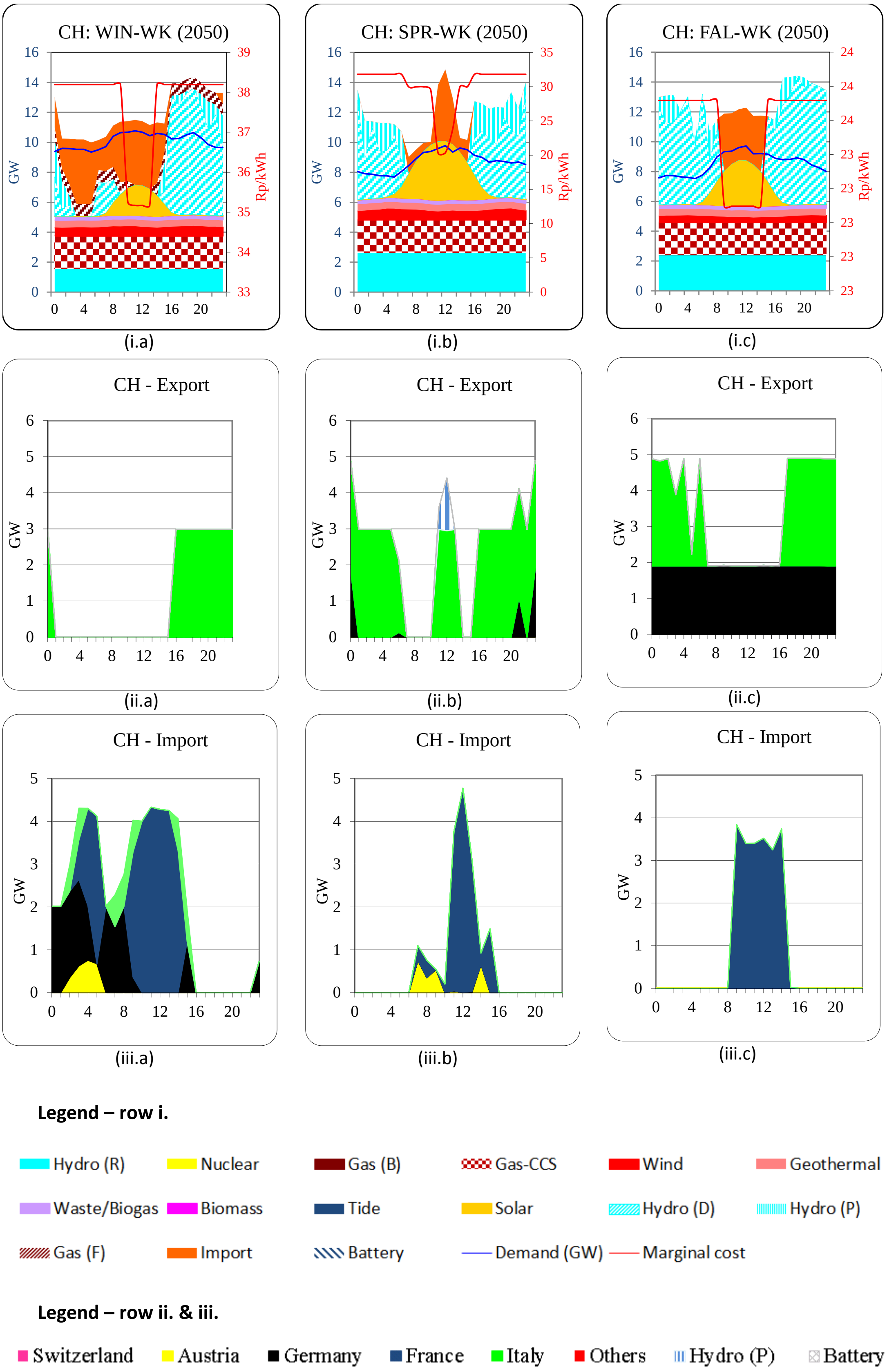


Figure 5-6: Switzerland generation schedules 2050 (*CO2*)

A closer inspection of Figure 5-5 also explains the reason why additional gas CCS investments are made in Switzerland rather than in Austria or France to export electricity to Germany. From Figure 5-5 ii.a and ii.d, it can be seen that Austria and France export a baseload equivalent to Germany throughout the day at the maximum interconnector capacity between these regions. As Germany still requires additional electricity to meet its demand, more electricity needs to be generated in Austria, France or Switzerland. As France and Austria already export at their interconnector capacity limits with Germany (see interconnector capacities given in Figure C1, Appendix C), increasing imports from these countries would require additional investments in interconnector capacities. On the other hand, since there is already around 3.5 GW of cross-border interconnector capacity existing between Switzerland and Germany, and as there is no cost-differentiation of technologies between the different regions, the cost-optimal solution is to invest additional gas CCS plants in Switzerland. This example also demonstrates the level of insights generated by CROSSTEM, which would not have been possible with a single region Swiss electricity model.

A similar trend is observed for Italy. As mentioned towards the end of section 5.4.1, Italy does not need to be a net importer of electricity, as it has sufficient resources to be self-sufficient. However, the generation schedule (Figure 5-5 column e) shows how Italy prefers to invest in solar PV technology due to its high availability factors, store the excess electricity from solar power during the day in batteries, and rely on electricity imports from Austria, France, Switzerland and fringe regions during the early morning and evening hours. In this manner, CROSSTEM utilises the capacities optimally, without investing in excess baseload plants.

Figure 5-6 shows the electricity generation and trade profiles for weekdays in other seasons in Switzerland. The different dispatch schedules are highlighted in the figure, particularly for flexible hydro plants. While the generation profiles for spring and fall resemble that of summer, the generation profile in winter is markedly different and reflects the seasonal availabilities of flexible hydro plants. In winter, Switzerland is a net importer of electricity while it is a net exporter in all other seasons, i.e. it follows current trends. Electricity imports come primarily from France; while exports are mainly to Italy and Germany (see Figure 5-7).

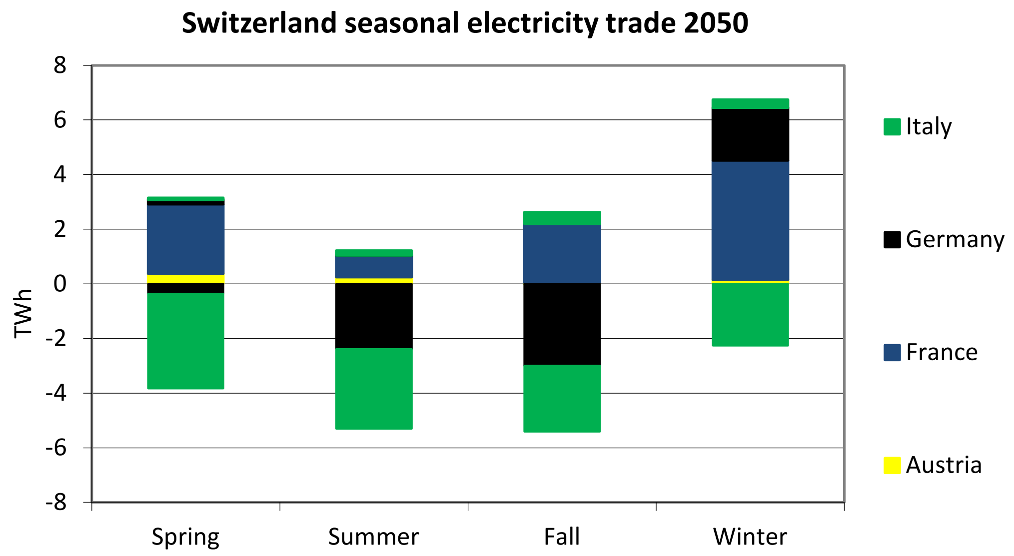


Figure 5-7: Switzerland seasonal trade patterns in 2050 (*CO2*): Negative numbers in the figure indicate electricity exports, and positive numbers denote electricity imports.

5.4.3 CO_2 emissions

Figure 5-8 shows total CO_2 emissions from Switzerland, and Figure 5-9 shows the total CO_2 emissions from all five countries, for the year 2010 and 2050 across all three scenarios. The CO_2 emissions in Switzerland increase by 51% relative to 2010 levels by 2050 for the ***Least Cost*** scenario, mainly due to the presence of gas plants (see Figure 5-2). This increase in emissions occurs despite EU 20-20-20 targets, which stipulated a 20% decrease in CO_2 emissions by 2020 and beyond (see section 5.3.3). However, since the emission reduction target is applied across all 5 countries together and not on a national level, it implies that certain regions can increase their CO_2 emissions provided that other regions correspondingly decrease their emissions, possibly far below what their national target would have been. For example, while emissions from Switzerland increase in the ***Least Cost*** scenario, Germany (-6%), France (-38%), Italy (-18%) and Austria (-50%) decrease their emissions by 2050 to achieve the overall CO_2 reduction target of 20% as shown in Figure 5-9.

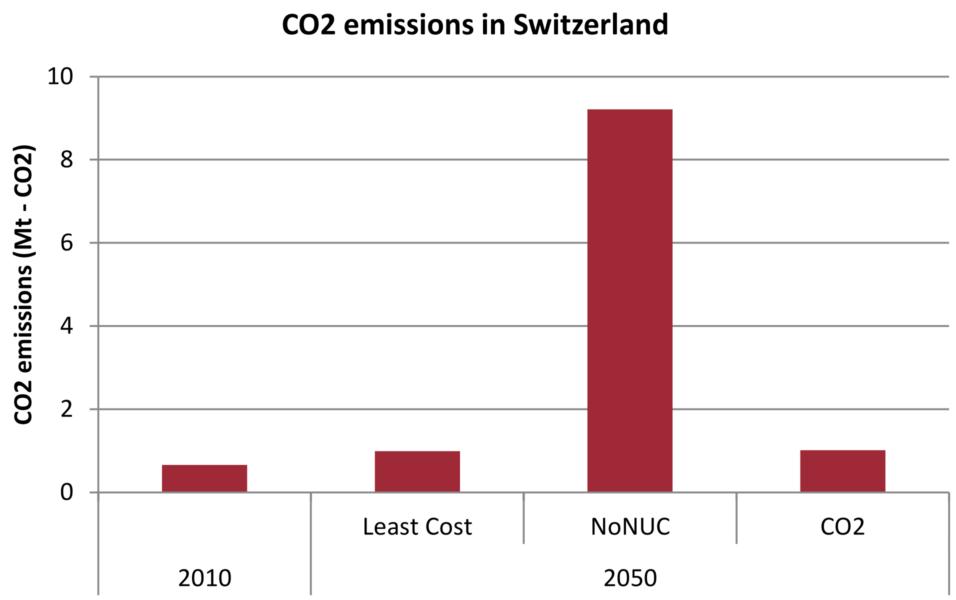


Figure 5-8: CO2 emissions in Switzerland

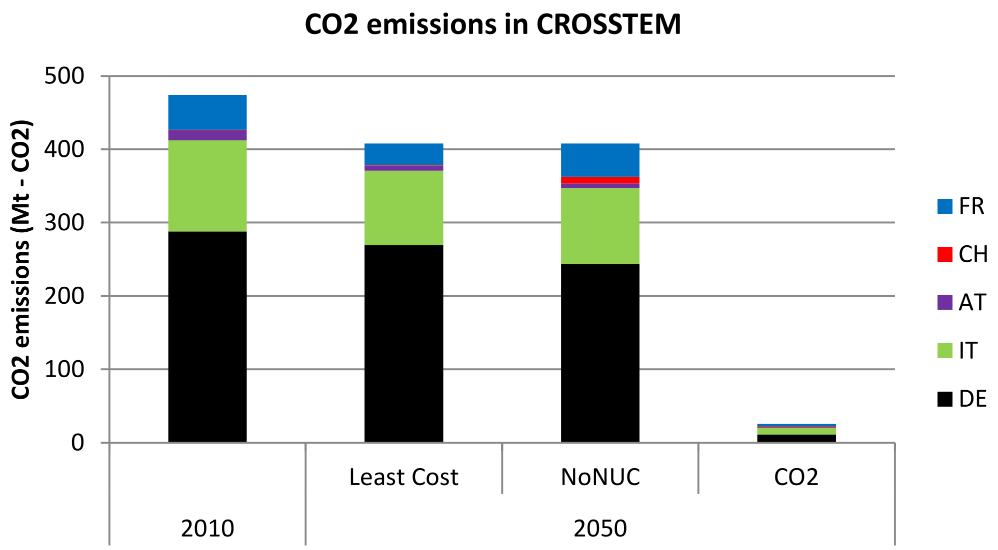


Figure 5-9: CO2 emissions in CROSSTEM

For the ***NoNUC*** scenario, emissions in Switzerland increase almost ten-fold compared to the ***Least Cost*** scenario (9.2 Gt CO_2 in ***NoNUC*** compared to 0.99 Gt CO_2 in ***Least Cost***, Figure 5-8). As the CO_2 emission targets are the same for the ***NoNUC*** and ***Least Cost*** scenarios, actual emission reductions occur elsewhere to compensate for increased emissions in Switzerland. Germany (-10%) and Austria (-17%) reduce their emissions in ***NoNUC*** compared to ***Least Cost***, whereas emissions from France (+56%) and Italy

(+2%) increase as gas plants are required to compensate for the reduced share of nuclear power (in France) and electricity imports (in Italy) (see Figure 5-4).

In the ***CO2*** scenario, considerable emission reductions are required to achieve the decarbonization target. Germany (-99.6%), Italy (-97%) and Austria (-94%) achieve the highest emission reductions compared to 2010. France reduces its emission by around 76% compared to 2010, although the CO_2 emission intensity of France is already quite low in 2010 compared to the other countries (see Table 5-2). Switzerland, on the other hand, increases its CO_2 emissions by approximately 360 Mt (or around 54%) in 2050 compared to 2010. This is due to the residual emissions from gas CCS plants in Switzerland. As discussed in section 5.4.2, Switzerland generates excess electricity from gas CCS plants which is exported to Germany, thereby increasing the domestic CO_2 emissions in Switzerland. In other words, Germany mitigates a part of its emissions in Switzerland, which results in an overall reduction in emissions from the five countries (see Figure 5-9) but consequently increases the domestic emissions from Switzerland (Figure 5-8). The impacts of applying CO_2 emission caps on a national level are discussed in the next subsection.

5.4.4 CO2 scenario variants

In the ***CO2*** scenario, the CO_2 emission cap was applied across all five countries together. This implies that some countries could emit more CO_2 for the benefit of other countries if it were cost-effective. Table 5-2 shows the CO_2 emission intensity (emissions per kWh of electricity demand) for the calibration year (2010) and the target emission intensities in 2050 if the CO_2 caps were applied nationally (by accounting for the future electricity demand).

Figure 5-10 shows the CO_2 emission intensities in the year 2050 for the ***CO2*** scenario. The red lines show the emission intensities if each country had to mitigate the emissions on their own, as described in Table 5-2. The figure reiterates the points made in the previous section on how the cost-optimal solution sees Germany mitigate a considerable amount of its emission in the neighbouring countries of Switzerland, Austria, France and Italy.

Table 5-2: CO2 emission intensity (2010 vs 2050 target)

Emission Intensity (g/kWh)	2010	2050 (target)
Austria	206	9
France	96	4
Germany	497	24
Italy	388	15
Switzerland	11	0.5

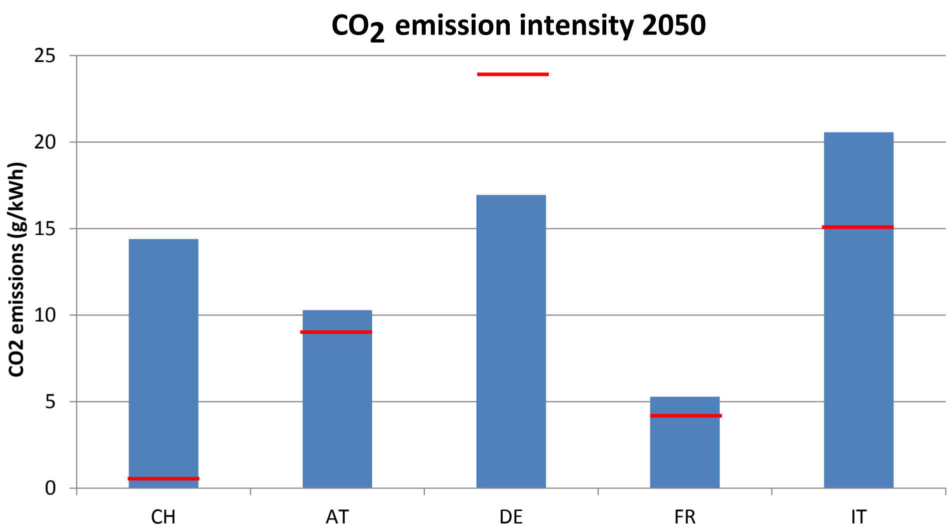


Figure 5-10: CO_2 emissions intensity in 2050 (*CO2* scenario)

A variant of the ***CO2*** scenario in which the CO_2 emission caps are applied on the national level (***CO2-NatCap***) was analysed to see the variations in supply mix for different countries. The electricity supply mix in Switzerland for the year 2050 is shown in Figure 5-11. The results for ***CO2-NatCap*** show that in order to meet the national emission targets, Switzerland has to reduce its investments in gas CCS plants to 0.9 GW in 2050 compared to 2.7 GW in the ***CO2*** scenario (corresponding electricity generation from gas CCS plants is 1 TWh in 2050 for ***CO2-NatCap*** compared to 20 TWh in the ***CO2*** scenario). Since the renewable potentials in Switzerland are insufficient to meet the high electricity demand, around 15 TWh of electricity (≈ 20% of the electricity demand) is imported. The imported electricity is generated primarily in France. Hence, in a high electricity demand scenario with national CO_2 emission targets, Switzerland has to mitigate its emissions in the neighbouring countries and become a net electricity importer. In other words, Switzerland cannot meet the 95% CO_2 emission reduction target without significant electricity imports if demand is inelastic to increased energy costs.

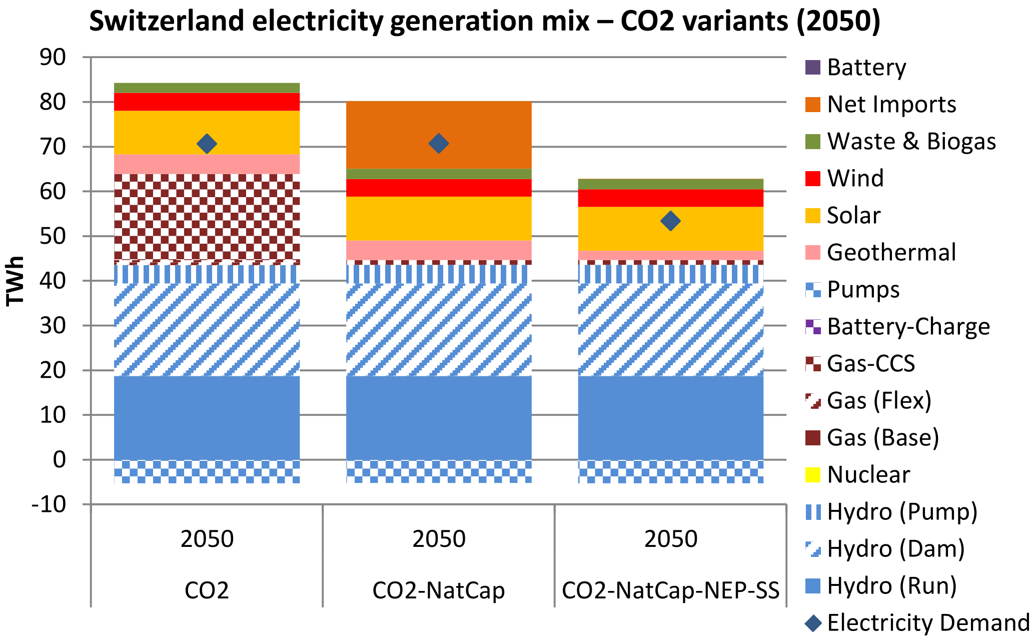


Figure 5-11: Switzerland electricity generation mix in 2050 - CO2 variants

Annual self-sufficiency in electricity supply, i.e. not relying on net electricity imports on an annual level, is one of the key questions that have been discussed in the Swiss energy strategy as well as by other study groups (Paul Scherrer Institute, 2012; Teske et al., 2013; VSE, 2012). Three out of the four supply scenario variants of the Swiss Energy Perspectives assume self-sufficiency in electricity supply (PROGNOS AG, 2012). While energy-independence is desirable from a political point of view, many experts point out that self-sufficiency in electricity generation makes little economic or ecological sense, especially in a future market with high integration of renewables (Rüegg, 2014). The analysis has shown that in order for Switzerland and its neighbouring countries to become self-sufficient, while adhering to their national emission targets, the electricity demands have to be reduced. The supply mix for Switzerland for such a low demand scenario (see Figure C5 Appendix C for demand assumptions) with national emission caps and self-sufficiency constraint is shown in

Figure 5-11, labelled as ***CO2-NatCap-NEP-SS***.

The next section discusses the costs incurred by the various scenario pathways discussed till now.

5.4.5 Electricity supply costs

As the CROSSTEM model optimises the cost for all five countries together, it is difficult[36] to infer national system costs. Nevertheless, Figure 5-12 shows the cost of investments in Switzerland per time period, for the three core scenarios. As expected, the ***CO2*** scenario has the highest investment costs, especially towards the end of the time horizon when substantial investments are made in capital-intensive solar PV and wind technologies. The cumulative investment costs during 2018 – 2050 is around CHF 80 billion for the ***CO2*** scenario, compared to CHF 55 billion for the ***Least Cost*** scenario. The ***NoNUC*** scenario has the lowest investment costs among the three scenarios, with the required cumulative investments being approximately CHF 40 billion. This is attributed to the lower investment costs for gas plants compared to capital-intensive renewable (***CO2***) and nuclear plants (***Least Cost***). The cumulative capital cost in the ***NoNUC*** scenario is approximately half of the ***CO2*** scenario; that is, the decarbonization of the power sector doubles the required investment costs.

When one considers the total undiscounted system cost[37] excluding the trade revenue, the cumulative costs over the time horizon is around CHF 275 billion for ***Least Cost***, CHF 305 billion for ***NoNUC*** (11% increase over ***Least Cost***) and CHF 332 billion for ***CO2*** (20% increase over ***Least Cost***). The ***CO2*** scenario has the highest costs, primarily due to the capital intensive renewable technologies as discussed before. ***NoNUC*** is more expensive than ***Least Cost*** mainly due to the higher fuel costs (gas prices).

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[36] For example, as discussed before, a part of the CO_2 mitigation for Germany in the CO2 scenario is met by the Swiss electricity system, implying additional costs for the Switzerland.

[37] Total system costs include capital costs, FOM and VOM, fuel costs, decommissioning costs, taxes and levies.

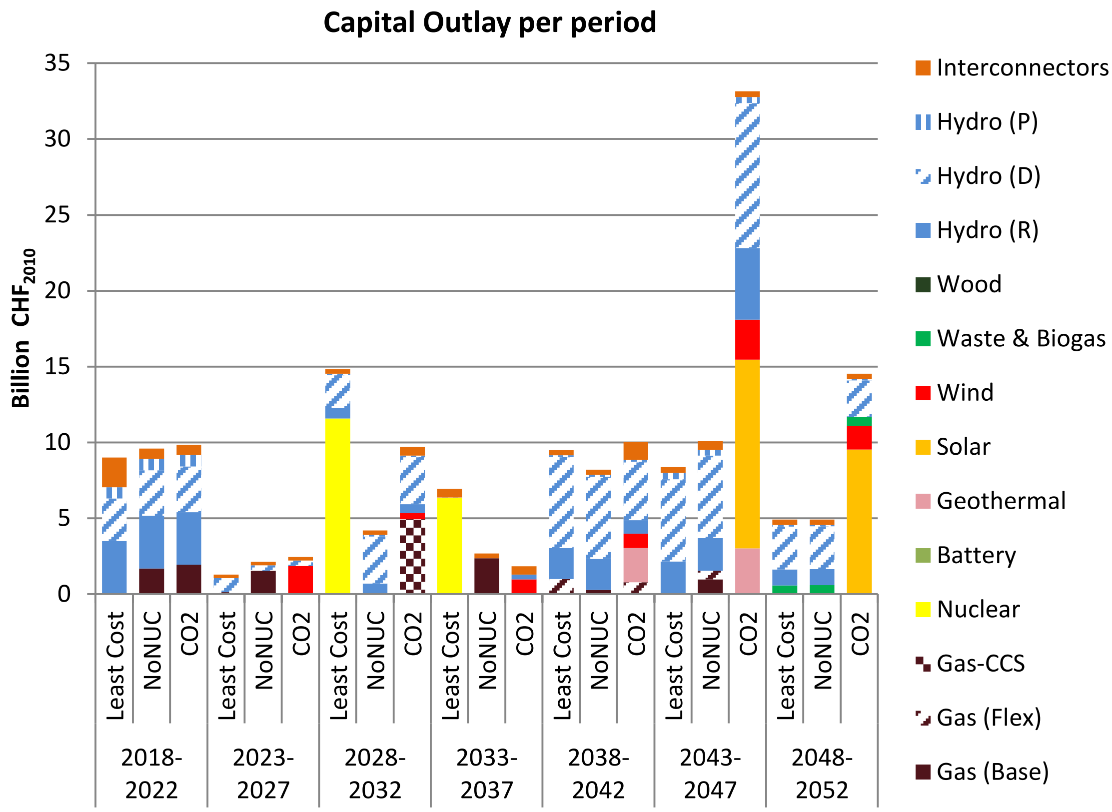

Figure 5-12: Investment costs in Switzerland per period

However, once trade revenues are incorporated in total system costs, the picture changes once again as shown in Figure 5-13. The red bars in the figure show the cumulative system costs in Switzerland (costs on left axis) while the blue markers indicate the cumulative costs for all CROSSTEM regions (right axis). The results show that ***NoNUC*** is the most expensive scenario, with the cumulative cost increasing by CHF 50 billion compared to ***Least Cost***. Costs for ***CO2*** on the other hand are on par with ***NoNUC***. This is because of the higher trade revenues in the ***CO2*** scenario, which amounts to around CHF 32 billion across the time horizon, or an average trade revenue of CHF 1.5 billion per year[38]. Hence, decarbonising the Swiss electricity system under a Europe-wide CO_2 emission cap would result in similar system costs as a scenario without climate mitigation targets (***NoNUC***) by offsetting additional investment costs via net electricity

[38] This is comparable with past trade revenues. For example, net electricity trade revenue in 2010 was CHF 1.3 billion.

trade revenue[39].

If the carbon targets were to be met at the national level (i.e. ***CO2-NatCap*** scenario), the total costs for Switzerland would be around CHF 35 billion higher than in the ***NoNUC*** or ***CO2*** scenarios. This is due to the absence of net trade revenue as Switzerland requires net imports to meet its demand (see section 5.4.4). The cumulative cost for all CROSSTEM regions also increases by approximately CHF 80 billion, highlighting that having a national cap on emissions is more expensive compared to an EU-wide emission cap.

Costs of two low-demand scenario variants are also shown in Figure 5-13. The general conclusion that can be drawn here is that low-demand pathways have considerably lower total system costs. Even the most stringent climate mitigation scenario with a lower electricity demand would be cheaper than the ***Least Cost*** scenario with high electricity demands. Another sensitive parameter is self-sufficiency in electricity generation. The ***CO2-NatCap-NEP-SS*** scenario has been described in section 5.4.4, and is a low-carbon, low-demand scenario with national emission caps as well as self-sufficiency constraints[40] for all regions (i.e., each country has to meet its electricity demand domestically). The cumulative system cost of this scenario is CHF 260 billion for Switzerland, and CHF 9692 billion for all CROSSTEM regions. If the self-sufficiency constraint is relaxed and electricity is allowed to be freely traded on the market, this cumulative cost reduces to CHF 248 billion for Switzerland and CHF 9588 billion for CROSSTEM regions (***CO2-NatCap-NEP*** in Figure 5-13). This shows that insisting on self-sufficiency in electricity supply results in higher costs, and that a liberalised and open electricity market with perfect competition is the cost-optimal pathway.

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[39] Decarbonising the whole CROSSTEM system, however, is more expensive, with additional investments of around CHF 1 trillion required in comparison to a reference scenario without climate mitigation targets (***NoNUC***) (see Figure 5-13).

[40] Self-sufficiency constraint is applied on an annual level, i.e. countries can be net importers in certain timeslices and net exporters in others.

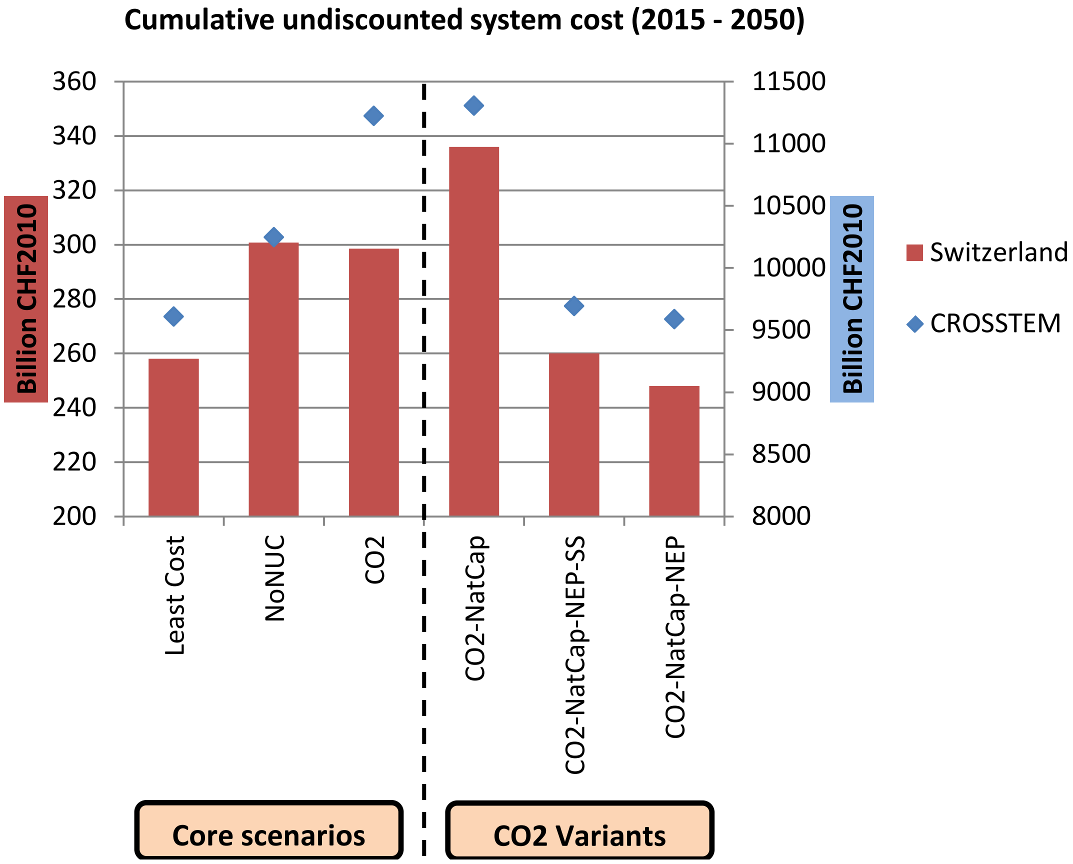

Figure 5-13: Cumulative undiscounted system costs (2015 - 2050)

Figure 5-14 shows the average electricity generation cost[41] in Switzerland for the year 2050 for the various scenarios. The results show that electricity costs in 2050 increase by 20% (***CO2***) to 70% (***CO2-NatCap***) compared to costs in 2010 for the high-demand scenarios. On the other hand, the stringent climate target scenario with low electricity demand (***CO2-NatCap-NEP-SS***) increases the cost by 30% compared to 2010, while relaxing the self-sufficiency constraint (***CO2-NatCap-NEP***) results in costs that are on par with today's costs.

[41] The average electricity cost is obtained by dividing the total undiscounted system cost in a year by the electricity demand.

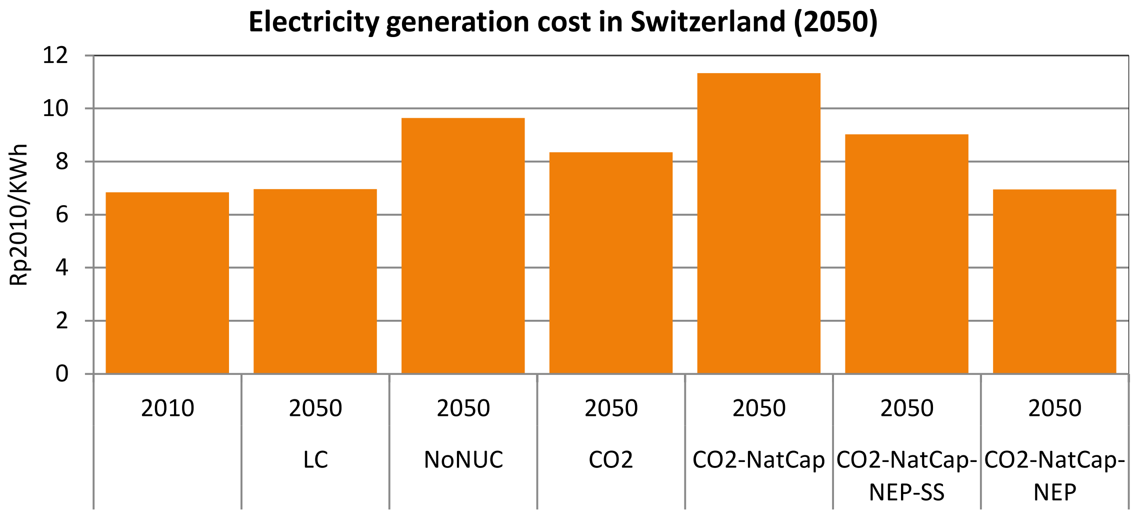

Figure 5-14: Switzerland average electricity cost (2050)

5.5 Sensitivity Analysis

There are several uncertain parameters/assumptions that could potentially influence the results discussed in section 5.4. Hence any policy decisions have to account for these uncertainties. Assumptions on future technology cost are one of the highly uncertain parameters. A detailed sensitivity analysis on technology costs can be found in literature such as (Kannan et al., 2012) and (Bosetti et al., 2015). Both of these studies single out nuclear technology in particular as a highly attractive low-carbon option. Results are found to be highly sensitive to nuclear technology costs in unconstrained emission scenarios (Bosetti et al., 2015). However, the impact of technology costs is minimised in constrained emissions scenarios such as the ***CO2*** scenario and its variants discussed in section 5.4. This is demonstrated in Figure C2 and C3 in Appendix C, which shows the supply mix of a ***CO2*** scenario with high nuclear (investment cost doubled) and low renewable technology (investment costs halved) costs. Results show only minor changes in the generation mix, as well as cumulative system costs, with variations in costs limited to 3 – 5% compared to the original ***CO2*** scenario. Another sensitive parameter closely related to technology costs is the discount rate. This parameter particularly affects technologies with high investment costs and change results significantly as highlighted in (Kannan et al., 2012).

For the current analysis, focus is shifted to two other parameters namely the effects of electricity trade with fringe regions on Switzerland, and alternative electricity load curves.

5.5.1 Impact of fringe regions

Although electricity imports and exports (price and trade volume) between Switzerland and its neighbouring countries are endogenous in the CROSSTEM model, the trade between the neighbouring countries and the wider EU regions (fringe regions) is still driven by exogenous assumptions in the analysis presented in the previous sections. A set of exogenous electricity prices (see Table 5-1) and historical trade volume assumptions have been used to simulate this trade, without considering the electricity markets in these regions. However, electricity trade volumes with fringe regions could be higher or lower in the future, and depend on developments in the electricity markets of those regions. Hence a sensitivity analysis was carried out to understand the impact of trade with fringe regions on the Swiss electricity supply.

A decarbonization scenario (***CO2***) variant in which trade with the fringe regions was deactivated was used for this analysis, and is referred to as ***CO2-FringeOff***. This implies that the five CROSSTEM regions must produce electricity and balance the supply and demand amongst themselves.

Figure 5-15 compares the electricity generation mix of ***CO2-FringeOff*** with the ***CO2*** scenario. In the years 2020 and 2030, baseload gas plants seen in ***CO2*** are almost completely replaced by flexible gas plants and electricity imports in ***CO2-FringeOff***. This means that the electricity system requires more flexibility to cope with variations in supply and demand, which was partly managed by the fringe regions in the ***CO2*** scenario. By 2050, the impact on Switzerland is minimal, as Switzerland becomes a net exporter due to developments in neighbouring regions (discussed in section 5.4.1) in both scenarios. However, changes are more prominent in other regions.

The analysis concludes that the trade with fringe regions has a secondary impact on the Swiss electricity system results. This is explored in more detail in Chapter 6.

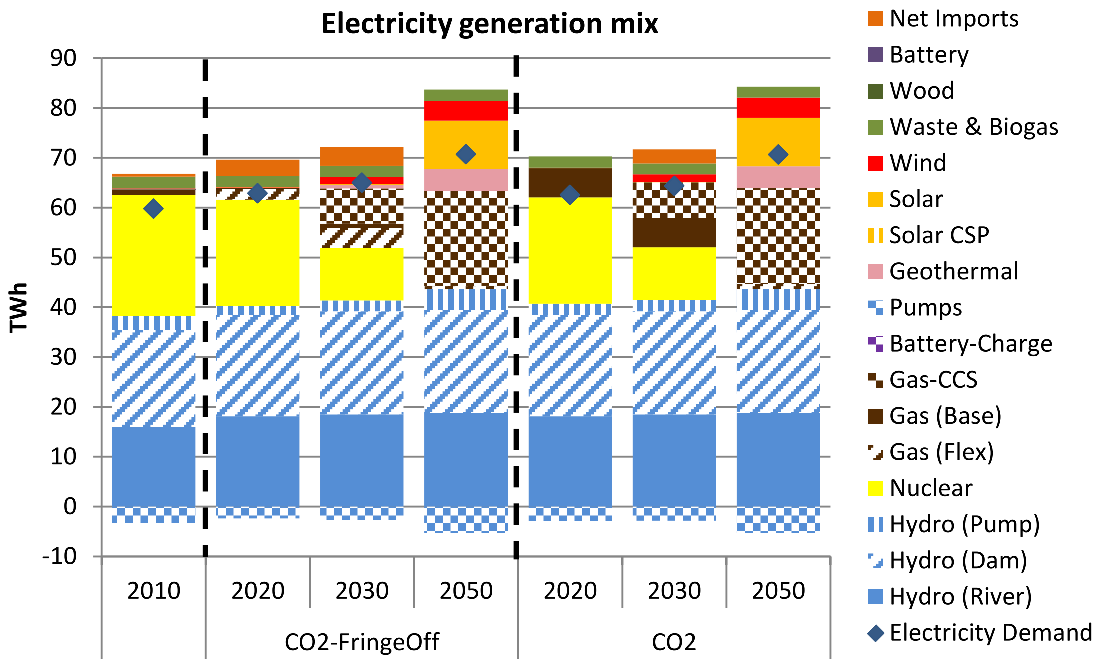

Figure 5-15: Switzerland electricity generation mix

5.5.2 Electricity load curve variations

One of the key assumptions in the model was the use of 2010 electricity load curves for the future years. This however seems highly unlikely, especially when an increasing electrification of the heating (via heat pumps) or transportation (electric vehicles, plug-in hybrids) sectors are foreseen. Increasing electrification of other sectors could potentially alter the hourly demand pattern, depending on the level of penetration of these technologies.

To understand the effects of such load-curve variations, an electricity load-curve was adapted from a "low-carbon scenario" (LC60) of the Swiss TIMES Energy model (STEM). The STEM scenario aims for a 60% reduction in total CO_2 emissions for the whole Swiss energy system by 2050 (Kannan & Turton, 2014). The electricity load-curves variations from 2010 to 2050 are shown in Figure 5-16. The y-axis denotes the fraction of annual electricity demand in a particular time-slice.

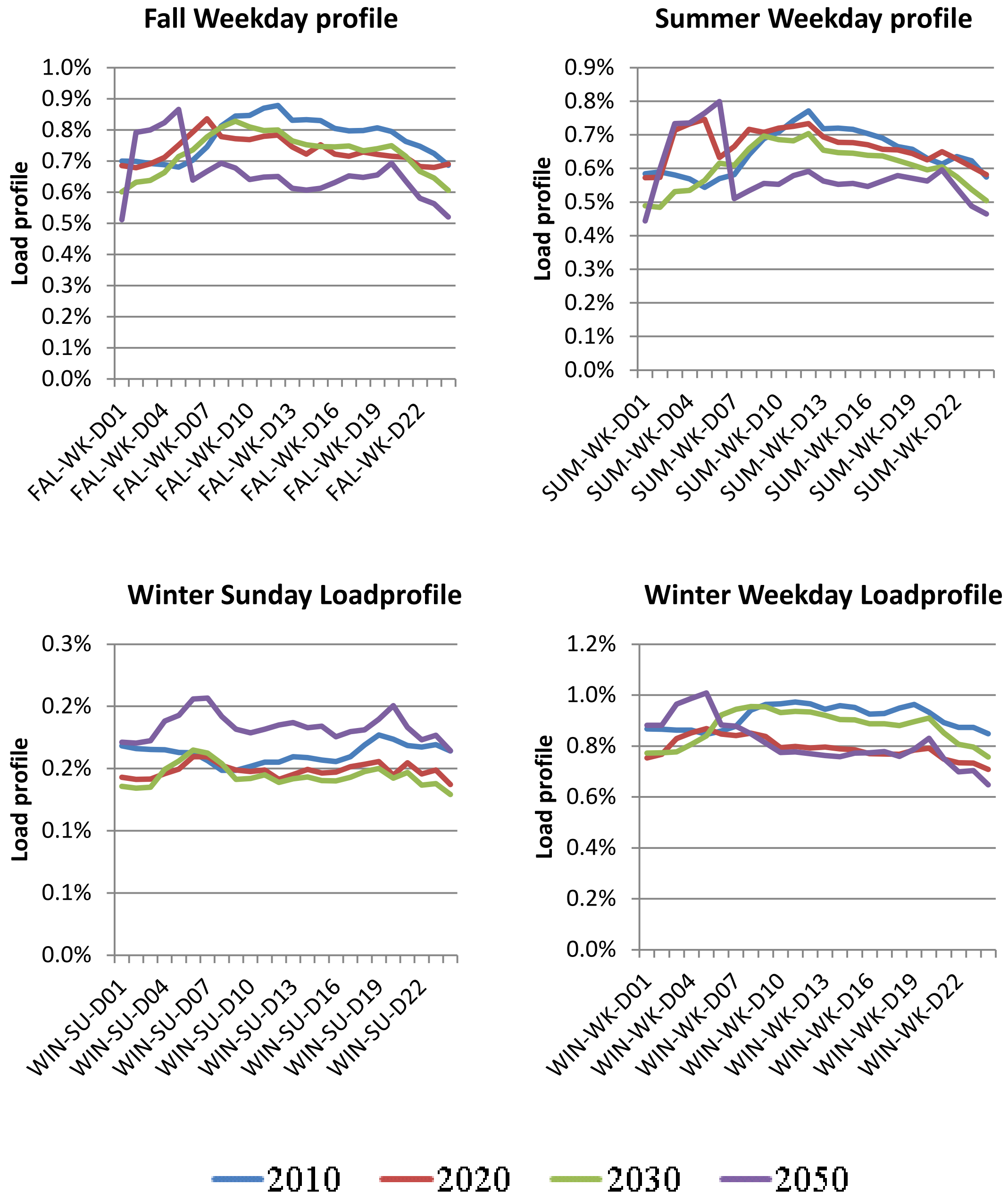

Figure 5-16: Electricity load-curves adapted from STEM LC60 scenario

Figure 5-17 shows the electricity generation mix for the decarbonization scenario (***CO2***) and the decarbonization scenario variant with the altered load curve for Switzerland[42] (***CO2-Loadcurve***). At a fist glance there is no notable difference between the two

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[42] Electricity demand profiles for neighbouring countries are unchanged

scenarios, with the generation mix almost identical. Closer inspection however reveals that there are small differences in gas based electricity generation and electricity imports. In 2020 for example, ***CO2-Loadcurve*** has a slightly higher production from gas plants (7 TWh) compared to ***CO2*** (5.8 TWh) which directly relates to a higher net export (increasing by 1.3 TWh). In 2030, gas and gas CCS based electricity production in ***CO2-Loadcurve*** is slightly lower (11.7 TWh) compared to the respective value in ***CO2*** (13 TWh), which is compensated by a higher electricity import. By 2050, the ***CO2*** scenario has an additional 1.3 TWh of flexible gas based output compared to ***CO2-Loadcurve***, which is exported.

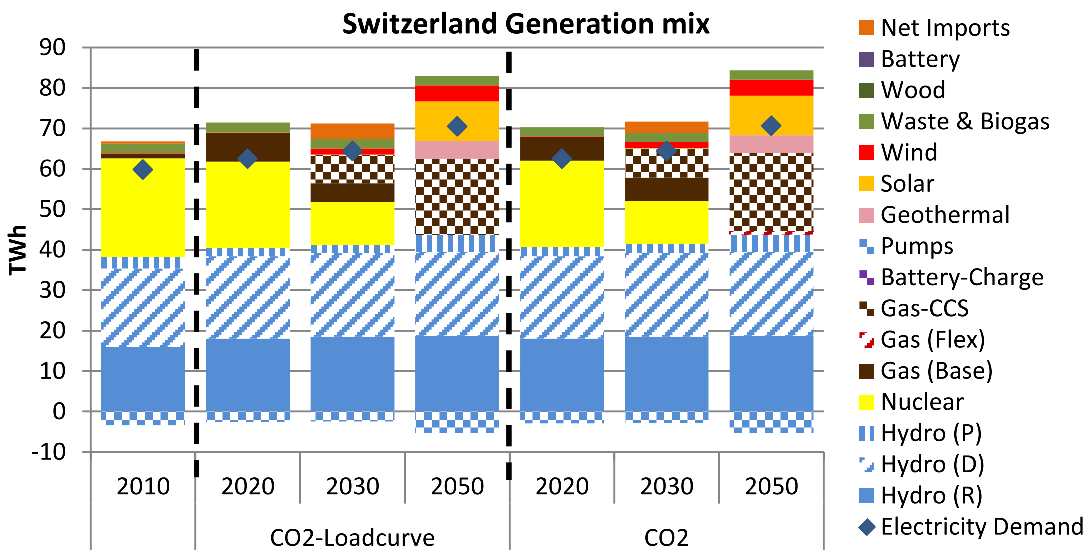
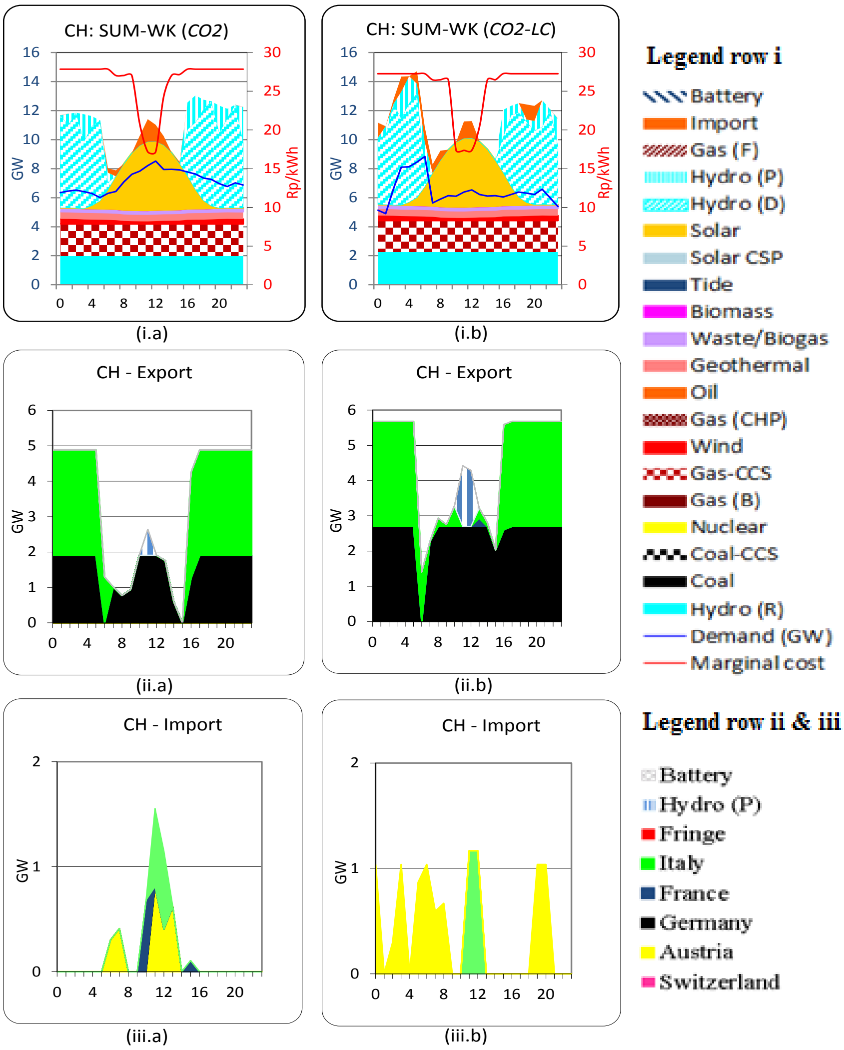


Figure 5-17: Swiss electricity generation mix

Figure 5-18 shows the electricity generation schedule in Switzerland and electricity import and export patterns on a summer weekday in 2050 for the ***CO2*** and ***CO2-Loadcurve*** scenarios. Although the demand profiles are considerably different, the dispatch profiles are very similar between the two scenarios. Flexible hydro plants are dispatched during the morning and evening hours with the surplus electricity exported to Germany and Italy. The peak demand in ***CO2*** occurs at noon, when electricity is also imported from Italy and Austria and stored via the pumped storage system.

In ***CO2-Loadcurve***, peak demand occurs between hours 03:00 and 07:00 (due to charging of electric vehicles[43], see (Kannan et al., 2014)). Hence, slightly higher flexible hydro is dispatched in the morning to meet the demand, and combined with electricity imports from Austria, excess electricity is exported to Italy and Germany. As the demand is quite low in ***CO2-Loadcurve*** at noon, more electricity is stored via pumped hydro storage than in ***CO2***.



CO2 ***CO2-Loadcurve***

Figure 5-18: Electricity generation schedule in summer weekday (2050)

This sensitivity analysis shows that despite the differences in load curves, there are

[43] It is worth noting that the peak demand occurs at night time due to charging of battery electric cars, as the electricity price during night was assumed to be low in STEM.

minor changes in dispatch schedules and overall electricity supply. This can be attributed to the high share of flexible generation in Switzerland, which enables the Swiss system to adequately cope with variations in the demand profile. However, it should be noted that demand profiles in other regions were unchanged for this analysis due to lack of alternative load profiles. The sensitivity analysis could be performed by altering load-curves for other regions which may have a greater impact on results.

5.6 Model limitations and uncertainties

The limitations discussed here are based on the analysis discussed in this chapter as well as in Chapter 4. Although we tried to implement consistent datasets (e.g. future electricity demand assumptions, technology cost curves, energy resource costs and potentials, etc.) wherever possible, they are potential sources of uncertainties and affects model results. Some limitations and uncertainties are described below.

- The future electricity demands are highly uncertain, and depend on their underlying drivers such as population growth, economic development, electrification of end use sectors, etc. Moreover, the electricity demand is inelastic in this analysis. Some implications of variations in electricity demands on electricity supply are presented in Chapter 4 and 5.
- Future technology cost assumptions depend on technology breakthroughs, which are highly uncertain. Sensitivity analysis has been done to understand impacts of varying costs in section 5.5.
- Energy resource potential of new renewables varies across literature, and is constantly updated. The renewable resource potentials in CROSSTEM are currently linearly interpolated between the 2010 level and 2050 potentials which limits an early/accelerated uptake of renewables.
- Some of the scenario specific user constraints are arbitrary assumptions. For example, the assumption regarding future trading patterns in Chapter 4 (see section 4.3.1.3), especially with fringe regions is highly uncertain. Countries that are currently net exporters could become net importers depending on national policies as well as developments in surrounding countries. Scenarios with no trade constraints are analysed in Chapter 5. Also, trade with the fringe regions is

modelled as a flexible technology, but the source of supply or market for export is highly uncertain. This limitation is further addressed in Chapter 6 using supplementary models.

- Though CROSSTEM has an hourly representation, it is not a dispatch model. Technology availability factors specified in the model represent a yearly technical availability factor, which includes outages due to scheduled maintenance, refuelling etc. However, unplanned outages are not captured in the model. Neither are issues such as start-up time nor technology ramping rates incorporated. The reserve margin is assumed to cope with such issues. In order to address this limitation, a supplementary model has been developed, and is discussed in Chapter 7.
- The representation of the average day is an over simplification in CROSSTEM, although such simplifications are common in many analytical frameworks due to computational constraints. For example, wind and solar PV availability factors are averaged over a season and week, and hence short term intermittency are not fully captured. However, the simplified intra-annual resolution largely complements the long model horizon of CROSSTEM. Chapter 7 discusses possible methods to address this limitation.
- Transmission and Distribution (T&D) networks are not modelled in any detail, i.e. the countries are modelled as single copper plate regions. There are some costs assigned to the transmission system (network tariff) but no explicit transmission lines are considered. Even though costs of interconnectors between countries are represented, losses are not included and are assumed to be captured by general assumptions on T&D losses. The model also assumes dispatchable electricity interconnectors between the countries, which do not take into account technical constraints of the electricity grid and thereby overestimate the ability to import/export electricity between the countries.
- The objective function of the CROSSTEM model minimises the total electricity system cost of all five countries together. This formulation of the objective function places more weight on the larger countries (like France and Germany) in the optimisation problem, which implies that the results discussed in this chapter may not necessarily be the most cost effective solution for Switzerland.

- Finally, the model assumes perfect information, perfect foresight, well-functioning markets and economically rational decisions, which is not always true in the real world.

5.7 Summary and Discussion

This chapter presents a set of scenarios demonstrating the long-term development of the electricity system of Switzerland and its neighbouring countries under various policy objectives, such as nuclear phase-out and CO_2 emission reduction. The analysis shows that irrespective of the nuclear phase-out and climate mitigation policies, significant new investments are required in the short- and long-term to replace retiring power plants. In the absence of any technology restrictions, nuclear power is the cost optimal electricity supply option to replace ageing nuclear and coal plants in Switzerland and its neighbouring countries (under the given cost assumptions regarding nuclear). Nuclear power has the advantage over conventional fossil fuel power plants in terms of both costs and CO_2 emissions. However, the risk and social acceptance aspect of nuclear generation is not considered in this analysis. This would place France in a very advantageous position as it is the only country among the five regions analysed in this study that does not aim for a complete nuclear phase-out, enabling it to continue being the electricity generation powerhouse in Europe, especially under stringent climate mitigation policies.

Under a nuclear phase-out policy and in the absence of any climate mitigation policies, coal power plants become the most cost effective source of electricity supply in all countries except Switzerland, especially in the near- to medium-term (2030). This is driven by increasing gas prices and relatively low coal price assumptions. However, investments in renewable and CCS technologies become attractive in the medium- to long-term (2050), mainly due to high CO_2 taxes and capital cost reduction of renewable energy technologies. For example, a CO_2 tax of 57 CHF/t-CO_2 alone is sufficient to reduce the emissions of the five countries by around 18% in 2050 compared to a scenario without any CO_2 tax and no emission caps. The cumulative total electricity system cost of all five CROSSTEM countries together increases by around 7% due to the nuclear phase-out strategy compared to the reference scenario.

As coal technology is not permitted in Switzerland as per scenario assumptions, gas-based generation is the cost-effective technology to replace nuclear generation in the near- to long-term. Renewable energy technologies are not competitive in Switzerland in the absence of any climate change mitigation targets, as better resource utilisation conditions for these technologies prevail in neighbouring countries. Instead, electricity imports are preferred to complement the domestic generation from gas plants and meet increasing electricity demand. On average, around 6% of the electricity demand is met by imported electricity over the entire time-horizon, which comes primarily from France and Germany. This is in stark contrast with other studies of the Swiss electricity system with similar scenario assumptions. The results from business-as-usual scenarios from the Swiss Energy Strategy 2050 (PROGNOS AG, 2012), the STEM-E model (Paul Scherrer Institute, 2012), and the SCS model (Super Computing Systems (SCS), 2013) point towards a significant renewable energy penetration (particularly solar PV) of 8 – 10% of the total demand, even in the absence of stringent climate policies. A comparison of similar scenarios between CROSSTEM and STEM-E models indicate that the single region STEM-E model always favours a higher penetration of solar PV compared to CROSSTEM (see section 4.3.4). This is attributed to the absence of electricity markets of neighbouring countries in single region models, which results in suboptimal investment decisions such as a higher penetration of renewable technologies. This issue is rectified in CROSSTEM.

To meet the stringent climate change mitigation objective of decarbonizing the power sector, far-reaching measures are required. In the short- to medium-term, a switch from coal-based electricity generation to natural gas-based generation is needed, particularly for Germany where more than 50% of the total generation in 2013 was from coal. This is in contrast with reality, as almost 12 GW of new coal and lignite power plants are planned to be constructed in Germany (Yang & Cui, 2012). Meanwhile, existing natural gas plants are being under-utilised in Germany and Italy as they are not competitive with cheap coal and highly subsidised renewable energy based generation in the current market (T. Andresen, 2013). The long-term operation of coal plants currently under construction will undermine climate mitigation goals unless they can be retrofitted for CCS once the technology becomes mature.

The analysis has shown that CCS technology is indispensable to meet the growing electricity demand under stringent CO_2 emissions reduction targets. The availability of carbon storage potentials plays a major role in determining policies for Switzerland. High carbon storage potentials allow Switzerland to be self-sufficient in meeting its increasing electricity demands as well as contribute to CO_2 mitigation efforts in some of the neighbouring countries, although this increases domestic CO_2 emission considerably. Minimising CO_2 emissions would require net electricity imports or a reduction in electricity demand. However, carbon storage potentials and social acceptance of carbon storage are still highly uncertain. Hence, policies in Switzerland and the neighbouring countries should address the barriers towards the adoption of this technology, as well as target new coal plants to have a CCS retrofit option. At the same time, economic and technological feasibility of CCS technology has to be demonstrated within the next decade in order to be able to attain the deployment rates seen in the current analaysis.

In the medium- to long-term, the onus ought to be on increasing investments in renewable technologies, such as solar PV and wind, to complement the fossil fuel power plants (with and without CCS). Increasing shares of renewable energy-based generation will require additional backup and storage systems amongst other balancing mechanisms. The analysis concludes that for an electricity system with a high share of intermittent renewable technologies, the storage capacity required to balance the system is around 10 - 15% of the total variable renewable capacity. Existing pumped hydro storages have to be complemented by additional battery storage technologies.

There are a number of trade-offs associated with each alternative supply option in terms of costs, CO_2 abatement and security of supply. CO_2 emissions would increase many fold unless external constraints are applied on the system in the form of CO_2 taxes or caps on emissions. Current CO_2 tax assumptions are not sufficient to reduce the CO_2 emissions to target levels, with the analysis showing that in order to achieve a decarbonization of the power sector by 2050, the CO_2 tax has to be as high as 670 CHF_{2010}/t CO_2. Attaining a 20% CO_2 emission reduction by 2020 and beyond requires a CO_2 tax of more than 100 CHF_{2010} / t CO_2. The CO_2 ETS prices today are around 8 EUR_{2015} / t CO_2 (European Energy Exchange (EEX), 2015), while predictions for future prices in 2050 are in the range of 50 CHF/t CO_2 to 300 CHF/t CO_2 (European Commission, 2011), values that are considerably lower than the figures found in this study. Development and expansion of interconnections between the countries, as well as market coupling, are prerequisites to balance the supply and demand in the wake of an increasing share of intermittent renewables in the electricity mix. Finally, although not a focus of this study, lower electricity demands due to increased end-use energy efficiencies and demand-side management would amend some of the challenges associated with these scenarios by reducing the need for more expensive supply options.

6 DEVELOPMENT AND APPLICATION OF THE EUSTEM MODEL

This chapter introduces the European Swiss TIMES Electricity Model (EUSTEM), which is a geographical extension of CROSSTEM. The EUSTEM model was developed and used for an INSIGHT-E[44] policy report on “Business models for flexible production and storage”.

The chapter begins with an introduction of the model and the motivation behind extending the CROSSTEM model to include more regions. This is followed by the methodology of the model and input assumptions. Two illustrative scenarios have been analysed to highlight the differences between EUSTEM and CROSSTEM when addressing Swiss specific issues, i.e. the impacts on the evolution of the Swiss electricity system when wider EU market developments are taken into account.

[44] INSIGHT-E is a European, scientific think-tank for energy related issues, providing advice to the European Commission on energy policy options (INSIGHT-E, 2015).

6.1 Introduction

One of the main shortcomings of the CROSSTEM model is the exogenous assumptions regarding electricity trade with fringe regions. These exogenous assumptions do not account for the electricity market developments in the fringe regions, i.e. the source of electricity supply for imports from- or market for electricity exports to- fringe regions are highly uncertain. Results of the generation schedule in chapter 4 (section 4.3.3.2) and chapter 5 (section 5.4.2) also show the phenomenon of "load-dumping", which was first discussed in Chapter 4 with respect to the single region model CROSSTEM-CH (see section 4.3.4.2). As the Swiss electricity trade with its surrounding countries is endogenous in CROSSTEM, the impacts of trading with fringe regions have been reduced for Switzerland compared to single region national models. Nevertheless, sensitivity analysis done on electricity trade with fringe regions (section 5.5.1) demonstrated that secondary effects still influenced the supply mix of Switzerland, highlighting the importance of European-level analysis. Although numerous European models exists such as the JRC EU-TIMES (Simoes et al., 2013) or the EU PRIMES model (E3MLab/ICCS, 2014), they differ in modelling methodologies, intra-annual resolution, besides the limited/simplified representation of Switzerland, making them unsuitable for such a comparative analysis. This was the rationale behind developing a new European electricity system model, which was methodologically consistent with the CROSSTEM model.

The European Swiss TIMES Electricity Model (EUSTEM) is a geographical extension of CROSSTEM to include electricity markets of erstwhile fringe regions of the CROSSTEM model. Hence, the exogenously defined electricity trade between the five modelled regions and the fringe region in CROSSTEM is endogenised in EUSTEM. This chapter analyses the differences between the two models regarding their results on the Swiss electricity system. The analysis aims at generating additional insights on the following issues:

- How much do developments in rest of Europe influence the Swiss electricity system in the long term?
- Is a model with higher geographical resolution necessary to analyse Swiss specific issues?

In addition to the above analysis, the development of the EUSTEM model also helps analysing European policies as the model now covers the electricity system of almost all of the EU-28 member states plus Switzerland and Norway. The model was used for the INSIGHT-E policy report on “Business models for flexible production and storage”, to assess the role of electricity storage in the medium to long term future for Europe. EUSTEM generated insights on possible electricity supply pathways to decarbonise the EU electricity sector by 2050, according to the EU Roadmap to 2050 scenario (European Commission, 2011). The model identified the long term capacity expansion plans to meet the given policy targets. To understand the real time dispatchability of the electricity system, the installed capacity data from EUSTEM was eventually tested in an EU-28 electricity market model developed by University College Cork (UCC), Ireland (Deane et al., 2015). It also described the revenue generated by storage processes to study the economic viability of pumped hydro and battery storage systems in current market conditions. The INSIGHT-E report is currently undergoing a final review process.

The next section describes the methodology, geographical scope and input assumptions of EUSTEM.

6.2 Overview of the EUSTEM model

Figure 6-1: EUSTEM regions

The EUSTEM model has 11 regions encompassing 20 of the EU-28 member states plus Switzerland and Norway (see Figure 6-1). These 20 countries in the EUSTEM model covered 96% of the total electricity supply and 90% of the total installed capacity of EU-28 + Switzerland & Norway in 2014 (ENTSO-E, 2014) (see Table 6-1).

Table 6-1: EUSTEM Regions - demand and capacity shares

Regions	Electricity demand (share of total electricity demand)	Installed Capacity (share of total installed capacity)
CROSSTEM (Austria, France, Germany, Italy, Switzerland)	47%	45%
Austria	2%	2%
France	16%	12%
Germany	18%	17%
Italy	9%	12%
Switzerland	2%	2%
EAST (Hungary, Poland, Czech Republic, Slovakia, Slovenia)	9%	7%
SPAPO (Spain, Portugal)	10%	12%
UKIRE (UK, Ireland)	11%	9%
NORDIC (Norway, Sweden, Finland, Denmark)	12%	9%
BENELUX (Belgium, Netherland, Luxembourg)	5%	4%
GRE (Greece)	2%	2%
Total Share of EU-28 + Switzerland & Norway	96%	90%

Several modelling and input data assumptions have been used in EUSTEM. In the following subsections, an overview of the model structure and key assumptions are described.

6.2.1 Model time-horizon and resolution

The European Swiss TIMES Electricity model has a time horizon of 70 years (2010-2080), divided into 8 unequal time periods as shown in Table 6-2. Each period also has an hourly representation within a year, differentiated by four seasons and three types of days similar to CROSSTEM.

The model is calibrated to actual data from IEA on electricity demand, generation mix, electricity trade and capital stock for the year 2010 (International Energy Agency, 2015). Operational characteristics of power plants, seasonal resource availabilities, electricity trade patterns and so on are included in the model. Existing generation technologies are calibrated to seasonal and annual electricity generation, as hourly level calibration was not possible due to lack of data.

Table 6-2: Time period definition in EUSTEM

Period Number	Period Duration	Time Period	Milestones years
1	1	2010-2010	2010
2	2	2011-2012	2011
3	5	2013-2017	2015
4	8	2018-2025	2021
5	10	2026-2035	2030
6	10	2036-2045	2040
7	10	2046-2055	2050
8	25	2056-2080	2068

6.2.2 Electricity demand

Figure 6-2 shows the electricity demands for the EUSTEM regions. For the analysis presented in this chapter, future electricity demands are adopted from the Reference scenario of the EU trends to 2050 study (European Commission, 2013) . The electricity demand for Switzerland is taken from the Swiss energy strategy 2050 (PROGNOS AG, 2012). For the intra-annual variations in electricity demand, electricity load curves from the year 2010 (ENTSO-E, 2014) are implemented for each region for the entire model horizon. This load curve assumption does not take into account for example the increasing electrification in the transport sector and/or space heating applications (e.g. electric vehicles, heat pumps), which could significantly alter future load curves.

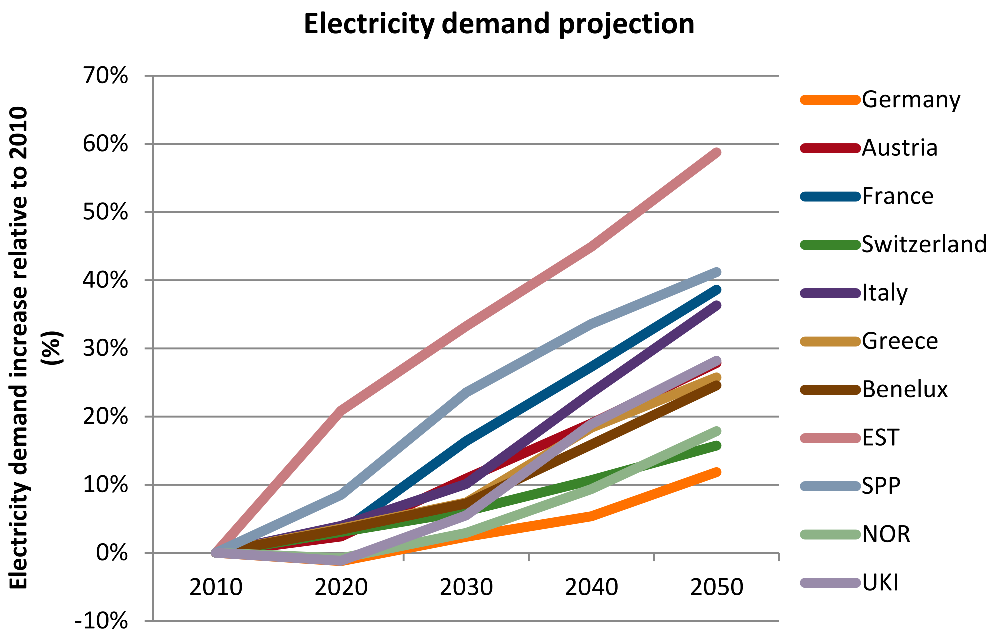


Figure 6-2: Electricity demand projections of EUSTEM regions

6.2.3 New electricity generation technologies

In addition to the existing fleet of technologies, the model has option to invest on new electricity generation technologies. Key techno-economic details of electricity generation technologies used in EUSTEM are the same as those for CROSSTEM and are given in chapter 3. The model also has the option to trade electricity between the regions based on marginal costs of generation, similar to CROSSTEM.

6.2.4 Renewable resources potential

A summary of the renewable potentials in different regions is given inTable 6-3. Technical renewable energy potentials for the additional regions are adopted from the JRC-EU-TIMES model (Simoes et al., 2013). For CROSSTEM regions, the renewable potentials assumptions remain the same as those used in Chapter 4 and Chapter 5.

Table 6-3: Renewable technical potentials

	Technical renewable energy potentials (2050) – PJ_{elc}										
	CH	AT	FR	DE	IT	EST	NOR	BNL	UKI	SPP	GRC
Solar PV	32.5	75	670	733	700	600	223	255	618	715	131
Solar CSP	-	-	-	-	36	-	-	-	-	38	15
Wind Offshore	-	-	4.4	461	1.5	11	250	48.6	83.6	122	38.5
Wind onshore	14.4	50	380	475	174	150	300	460	198	370	74.8
Biomass	122	8	119	101.1	33	50	124	60.8	44	33	5
Waste	8.1	3.08	16	21.2	18	12	22	20	12	20	1.5
Geothermal	16	2	1.71	20	26	15	0.1	5	0.6	35	1
Hydro Dam	74.5	31.1	131	3.6	50	8	628	0.3	8	146	29
Hydro Run of River	47.2	116.9	135	86.4	80	50	406	2.4	12	86	4
Tide	-	-	55	-	11	23	100	4.3	375	93	14.4

6.2.5 Energy Resource Costs

The energy price assumptions are the same as those used for CROSSTEM in Chapter 5. Thus, fuel prices for natural gas, oil and coal were taken from the World Energy Outlook 2014 (International Energy Agency, 2014). Cost of uranium fuel rods was taken from (Paul Scherrer Institute, 2010). The energy prices from 2050 are extrapolated to the remainder of the model time horizon.

6.2.6 CCS potentials

Carbon Capture and Storage (CCS) technologies are assumed to be available from 2030. The market potential of CCS technologies are limited by the CO_2 storage potentials; and the storage potential are taken from the EU studies (EU Geocapacity, 2009; Simoes et al., 2013). It is worth noting that the CO_2 storage potentials are limited to 30% of the hydrocarbon field potentials for a conservative estimate[45] (see Figure 6-3).

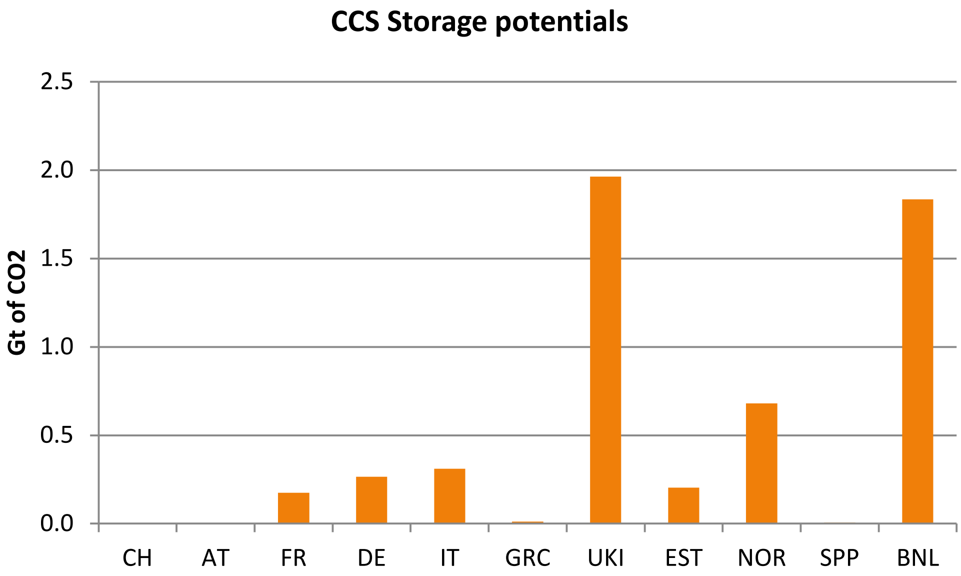


Figure 6-3: CCS Storage potentials

6.2.7 Country-wise nuclear policies

Table 6-4 describes the various nuclear policies in different countries that have been implemented in the EUSTEM model. These policy constraints are applied to all scenarios. As mentioned in Chapter 5, although nuclear technology is a cost effective low-carbon source of electricity in the model (especially under stringent climate policies), socio-political factors have a bigger impact on nuclear deployment than economic factors. The countries specified in Table 6-4 have declared their nuclear expansion or phase-out policies. Other countries such as Italy, Austria, Norway, Portugal, Greece and Ireland do not consider nuclear power in their future power portfolio. The country-wise policies have been adopted from (IEA, 2013) and (World Nuclear Association, 2014a).

[45] The low CCS potentials are used also for CROSSTEM in this chapter (see low CCS potentials in section 3.4.8 of Chapter 3)

Table 6-4: Nuclear policies in EUSTEM countries

Country	Policy
Belgium	- Nuclear phase-out, existing seven plants to be closed by 2025
Netherlands	- Existing nuclear power plant to go offline by 2033
Czech Republic	- 1.2 GW of new nuclear capacity by 2030
Hungary	- Nuclear lifetime of the existing 4 nuclear plants extended by 20 years. 1.8 GW of nuclear capacity to be retired by 2034
Poland	- Plans to introduce nuclear power in its electricity generation mix - First nuclear plant to start operation by 2022 - Target of 4.5 GW nuclear capacity by 2030
Slovakia	- 2 nuclear power plants currently under construction, first operation expected by 2017/2018 - Slovakia's long term energy plan is to keep the share of nuclear constant at around 50% of the total supply mix - Lifetime of existing plants extended from 40 to 60 years
Finland	- Raise the share of nuclear power to 60% of the supply mix by 2025 - 4.8 GW of nuclear capacity under construction, first operation expected in 2020
UK	- 8 GW of nuclear capacity to be retired by 2020, another 1.2 GW retired by 2035 - Plans to construct around 19 GW of new nuclear capacity, 16 GW by 2030
Spain	- Spain in a dilemma between nuclear phase-out and extending lifetime of existing plants - A lifetime extension by 20 years implies constant nuclear capacity until 2050
Sweden	- Sweden to phase out its existing nuclear plants. Last plant to come off-grid by 2035 (assuming 50 year lifetime)
Switzerland	- Nuclear phase-out, last plant off-grid by 2034 (50 year lifetime)
Germany	- Complete nuclear phase-out by 2023
France	- Nuclear fleet can be replaced, up to today's level

6.3 Scenarios

Two illustrative scenarios have been selected for analysis in this section.

6.3.1 Least Cost scenario (*Least Cost*)

This scenario gives least cost electricity supply mix in a future absent of any climate mitigation policy or renewable targets. In this scenario, no specific constraints on technologies are included, except the existing national policies on nuclear phase-outs[46]. Technology growth constraints have been applied to the total installed capacity of technologies such as coal, wind and solar PV based on their historical trends to reflect plausible technical limits to deploy them and thereby prevent their unrealistic penetration. A CO_2 tax is implemented based on the EU ETS prices from the "Business As Usual" scenario of the Swiss energy perspectives (PROGNOS AG, 2012). The CO_2 price varies between 16 CHF_{2010}/t-CO_2 in 2010 and 58 CHF_{2010}/t-CO_2 in 2050 and is similar to assumptions in the Reference scenario of the EU Energy Roadmap (European Commission, 2011). No particular market or interconnector constraints are applied on electricity imports / exports between regions, i.e. the model has full freedom to trade electricity and to expand its cross-border interconnector capacity.

6.3.2 Decarbonization scenario (*CO2*)

The decarbonization scenario has the same boundary conditions as the ***Least Cost*** scenario, with an additional CO_2 emission cap to decarbonise the EU electricity sector by 2050. The scenario aims to reduce CO_2 emissions across the regions by 61% of the 1990 levels by 2030, and 95% by 2050. These emission caps are in line with the CO_2 emission targets in the EU energy roadmap to 2050 (European Commission, 2011). It is worth noting that the carbon constraint is applied across all the regions together and not at the national level.

[46] These include only confirmed phase-out policies as mentioned in Table 6-4. France is assumed to retain its nuclear fleet up to today's generation levels. Similar assumptions are used in CROSSTEM as well for this chapter.

6.4 Results – EUSTEM vs CROSSTEM

The electricity supply mix and generation cost results for Switzerland are presented in the following subsections. This section highlights the differences in results for Switzerland when wider EU markets are taken into consideration.

6.4.1 Least Cost scenario

Figure 6-4 shows the electricity generation mix of Switzerland for the ***Least Cost*** scenario, from the CROSSTEM and EUSTEM models. In the CROSSTEM model, the retiring nuclear plants are replaced by flexible gas plants (supplying 13% of demand by 2050) and imported electricity (31% of demand by 2050). Electricity imports are attractive as there are cheaper base-load generation options available in surrounding regions (primarily coal based generation in Germany). The results from EUSTEM are similar; however there is a change in the share of imports and flexible gas plants in the supply mix throughout the model time horizon. For example, in 2050, the share of flexible gas based generation is 13% of the demand in CROSSTEM, whereas it is 18% in EUSTEM. On the other hand, share of net imported electricity reduces from 31% of the demand in CROSSTEM to 24% in EUSTEM. The imported electricity in the Swiss supply mix comes primarily from Germany, similar to CROSSTEM.

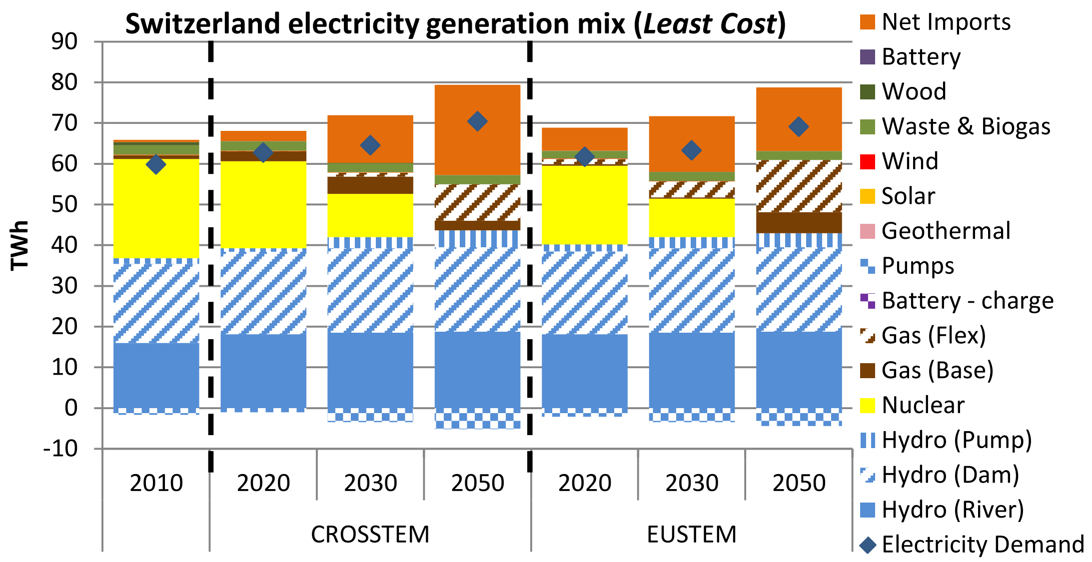


Figure 6-4: Swiss electricity generation mix in *Least Cost* – CROSSTEM vs EUSTEM

The reason for the reduced exports can be explained by analysing the generation mix in Germany (see Figure 6-5). It can be observed that the overall electricity generation for Germany in EUSTEM is slightly lower than in CROSSTEM, consequently resulting in lower exports of electricity (20 TWh less exports in EUSTEM compared to CROSSTEM). The reduced production is particularly noticeable from wind, whose share reduces from 8% of the demand in CROSSTEM to 3%. Instead, generation from flexible gas plants in Germany is doubled in EUSTEM compared to CROSSTEM.

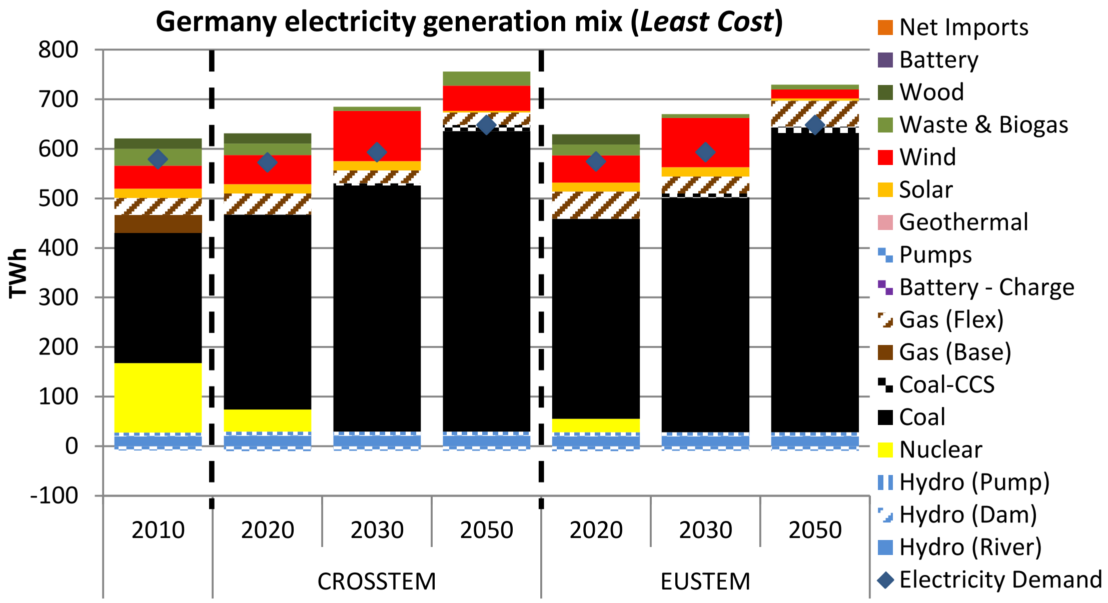


Figure 6-5: Germany electricity generation mix in *Least Cost* – CROSSTEM vs EUSTEM

The results described above show the impacts of representing the electricity markets of the fringe regions. As mentioned before, electricity trade with fringe regions in CROSSTEM is analogous to a flexible technology, with imports and exports determined only by electricity costs without considering the electricity markets in these neighbouring regions. On the other hand, by representing the electricity markets of these fringe regions, EUSTEM removes the “flexibility” of the fringe regions, which forces regions to install alternative load following technologies such as flexible gas plants. This has knock-on impacts the Swiss electricity generation mix as well. For example, flexible generation is underrepresented by around 50% in CROSSTEM compared to EUSTEM.

6.4.2 Decarbonization scenario (CO2)

The electricity generation mix of Switzerland for the decarbonization scenario (***CO2***) is shown in Figure 6-6. The near and medium term results reiterate the points made in section 6.4.1, with EUSTEM results indicating the need for additional flexible generation compared to CROSSTEM. In the long term (2050), there is an installed capacity of 0.8 GW of flexible gas based generation in EUSTEM compared to none in CROSSTEM. Larger variations are seen in the electricity production from solar PV and electricity imports. Solar PV penetration decreases by half, with only 7% of the demand covered by solar PV in EUSTEM compared to 14% in CROSSTEM. The decrease in solar output is compensated with higher electricity imports, with net imports increasing from 18% of the total demand in CROSSTEM to 23% in EUSTEM. The imported electricity in the Swiss supply mix of CROSSTEM is predominantly generated in France, and amounts to around 20 TWh in 2050. In EUSTEM, electricity imports from France to Switzerland is reduced to 16 TWh in 2050; with the remaining imported electricity produced in BENELUX and NORDIC regions and transmitted to Switzerland through Germany.

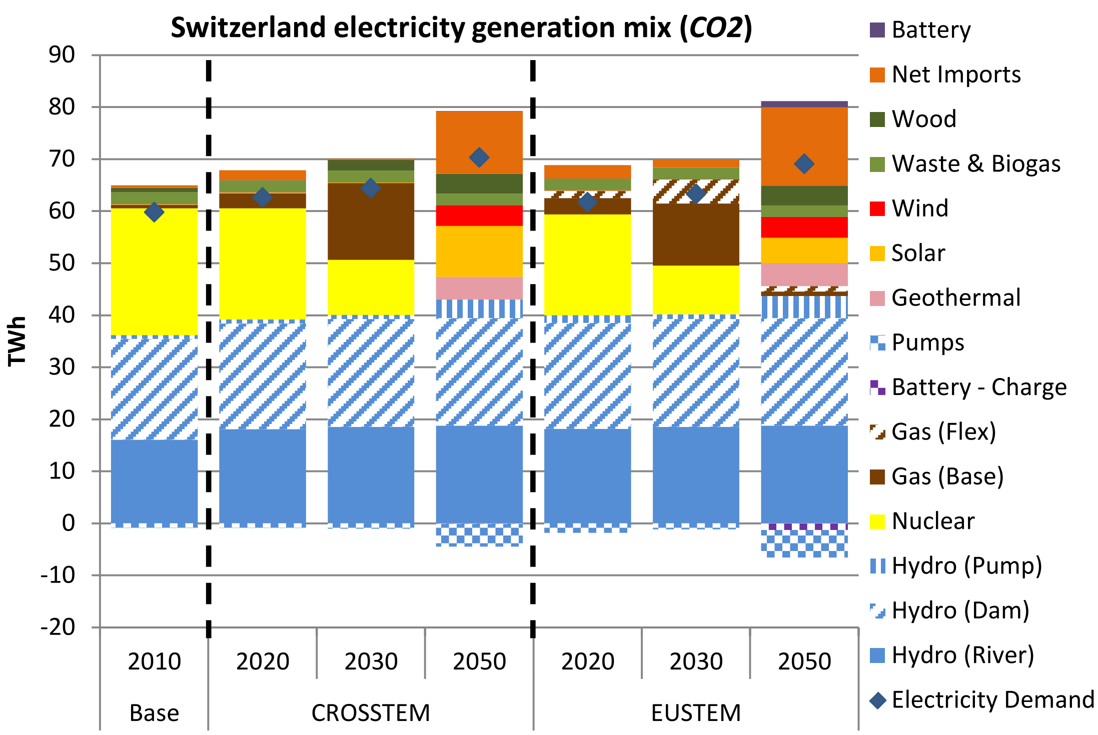


Figure 6-6: Swiss Electricity generation mix (CO2); CROSSTEM vs EUSTEM

Besides the changes described above, there are new investments in battery storage for Switzerland in EUSTEM, despite the decrease in intermittent solar PV generation compared to CROSSTEM. Around 2 GW of battery storage is installed in Switzerland in addition to the 2.5 GW of pumped hydro storage. The battery storage is mainly used to store excess solar PV outputs during the weekends (see Figure 6-7). In CROSSTEM, the excess electricity from Switzerland was dumped to the fringe regions via the neighbouring countries; thereby avoiding investments in additional storage.

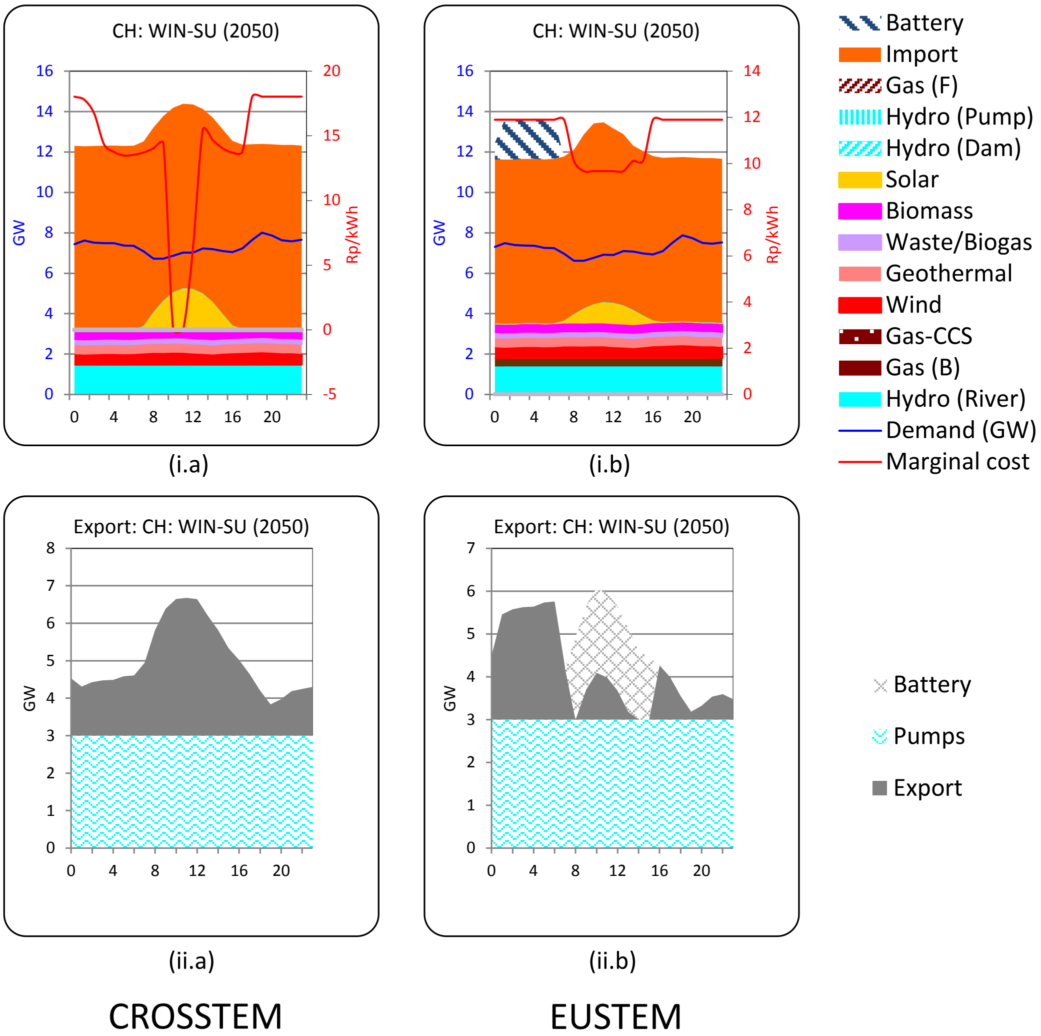


Figure 6-7: Switzerland generation schedule winter Sunday 2050 (*CO2*)

The differences in supply mixes between the models are also reflected in the corresponding cost numbers. Figure 6-8 presents a comparison of the average electricity generation costs in Switzerland for the year 2050. In both scenarios, costs in EUSTEM are higher than in CROSSTEM. For the ***Least Cost*** scenario, the average electricity cost in 2050 is 5% higher than in CROSSTEM. For the ***CO2*** scenario, the difference increases to 10%. This is because in both scenarios, there is a higher share of flexible gas plants in EUSTEM, which are less efficient and thereby more expensive. Electricity generation costs in neighbouring countries are also more expensive in EUSTEM for similar reasons, which imply that the cost of imported electricity is also higher compared to CROSSTEM.

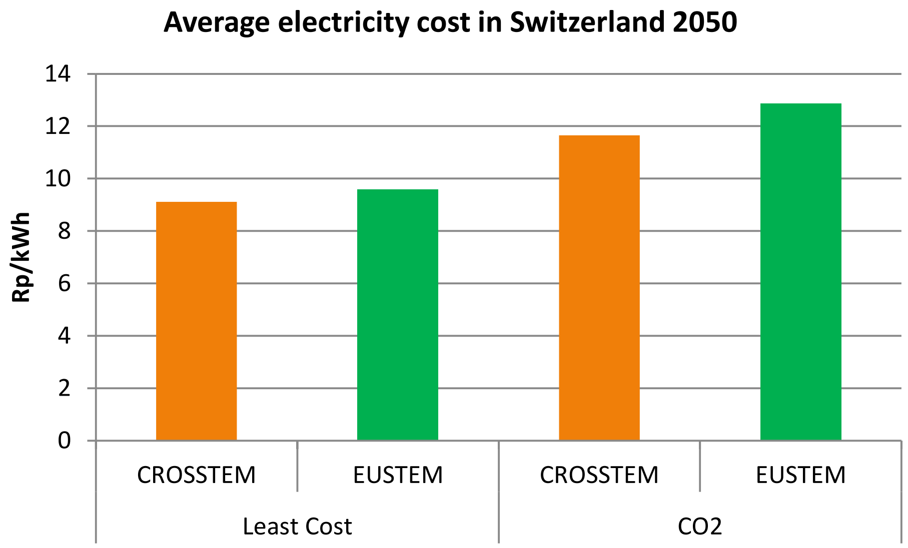


Figure 6-8: Average Swiss electricity cost in 2050 – CROSSTEM vs EUSTEM

6.5 Conclusion

The comparison of the results from CROSSTEM and EUSTEM highlight the impacts of wider EU electricity markets on evolution of the Swiss electricity system. By avoiding the representation of electricity markets in erstwhile "fringe" regions of CROSSTEM, there is a considerable overestimation of renewable penetration, as well as an underrepresentation of storage and flexible generation technologies required to balance the system. The penetration of solar PV technology is particularly affected, with solar PV investments in Switzerland lower by around 50% in EUSTEM compared to CROSSTEM. The same holds true for the surrounding countries as well (for example, solar investments in EUSTEM are around 30 GW lower for Germany, and 20 GW lower for France compared to CROSSTEM). There is also an underestimation of the storage capacities required to balance the system, implying that for a future decarbonised electricity system in EU, having a high share of solar PV capacity requires corresponding investments in battery or flexible storage technologies.

The variations in supply mixes between the two models also result in cost differences. The analysis shows that the average electricity generation cost in CROSSTEM is underrepresented by around 5 – 10% depending on scenario assumptions. Cumulative undiscounted system costs for Switzerland are underrepresented by around 15% in CROSSTEM (≈ CHF 35 billion).

The consideration of wider EU electricity markets also enables more effective utilisation of resources. For example, the EUSTEM model exploits higher CCS storage potentials in BENELUX and NORDIC regions, higher wind and hydro potentials in NORDIC regions, as well as cheaper base load electricity from nuclear investments in UKI or EAST. The analysis concludes that the impacts of representing the electricity markets in fringe regions on the Swiss electricity system are significant enough to warrant the geographical expansion of the CROSSTEM model.

7 CROSSTEM HOURLY GENERATION MODEL (CROSSTEM-HG)

One of the limitations of the CROSSTEM model is the oversimplification of hourly electricity supply and demand through representative days. By averaging the solar and wind profiles over a season, the model does not fully capture the real time variability of the highly intermittent renewable technologies, especially wind power. In order to better capture these intermittencies and analyse the supply-demand balancing mechanism, a supplementary model named CROSSTEM-*Hourly Generation* (CROSSTEM-HG) has been developed. The CROSSTEM-HG model is an ad-hoc approach in simulating certain dispatch aspects that could not be captured with the CROSSTEM model.

This chapter explains the methodology and application of the CROSSTEM-HG model. The chapter gives a brief introduction regarding the motivation for developing CROSSTEM-HG, followed by an overview of the modelling methodology. Subsequent sections discuss the key results and insights generated by the model. The chapter concludes with an outlook on how the model can be refined further and identifies other alternative applications of it.

7.1 Introduction

As mentioned in Chapter 2, integrating intermittent renewable (IRES) technologies in long term capacity expansion models is a challenging task, and requires a high level of temporal, spatial and technical detail (Poncelet et al., 2015). Long term models typically have a limited representation of intra-annual details, which leads to sub-optimal investment decisions with respect to IRES technologies. Often, there is an overestimation of IRES penetration in the supply mix, or a corresponding underestimation of storage or flexible generation requirements needed to balance the electricity system. Combining dispatch aspects in long-term planning models is computationally challenging (Connolly et al., 2009; Kannan et al., 2013; Welsch et al., 2014), which has led to several ad-hoc approaches to address this problem (Deane et al., 2015; Luderer et al., 2014; Ueckerdt et al., 2015). While each of these approaches has its own merits, they also have their disadvantages. For example, the electricity market model by (Deane et al., 2015) is a dispatch model which analyses the dispatchability of a given installed capacity; i.e. the model does not provide insights regarding capacity expansion. (Ueckerdt et al., 2015) adopted the residual load duration curve method to analyse the impacts of IRES in capacity expansion models. However, this approach ignores the chronological order of the electricity demand and supply, which makes it unsuitable to address short term electricity storage issues.

Another approach that has been frequently used is increasing the intra-annual detail via higher “timeslices” or representative hours in long term planning models. There are several methods for choosing representative timeslices as discussed by (Poncelet et al., 2015), and this approach is used in various models in literature (Energiewirtschaftliches Institut (EWI), 2008; Kannan et al., 2011, 2014; Poncelet, Delarue, et al., 2014a), in addition to the two models (CROSSTEM, EUSTEM) described in this thesis. By representing the 8760 hours in a year via 288 representative hours (i.e. timeslices[47]), the models are able to capture certain aspects of IRES variabilities by applying hourly demand load curves, and solar and wind hourly availabilities. Results from this

[47] 288 is the number of timeslices used in DIME (EWI), STEM-E (Kannan & Turton 2011), CROSSTEM and EUSTEM.

approach have already been described in Chapter 4, 5 and 6. Despite the advantages of the models described above with their increased number of timeslices, there is still an oversimplification of the intermittency issue from variable renewable technologies such as solar PV and wind. Figure 7-1 shows the generation schedule of a spring weekday in Germany for the stringent climate change mitigation scenario (***CO2***) described in Chapter 5 (see section 5.3.2). The electricity generation from solar PV (shown by the yellow area in Figure 7-1) follows the average solar availability profile for the spring season, shown by the red line in Figure 7-2. The model, having perfect foresight, is able to balance the system without needing additional flexibility as the solar and wind availability profiles remain unperturbed throughout the model horizon.

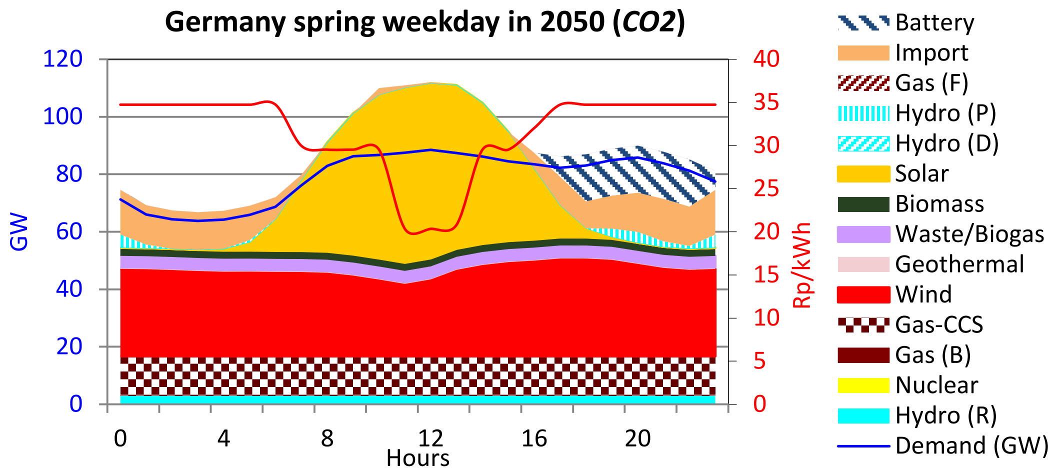
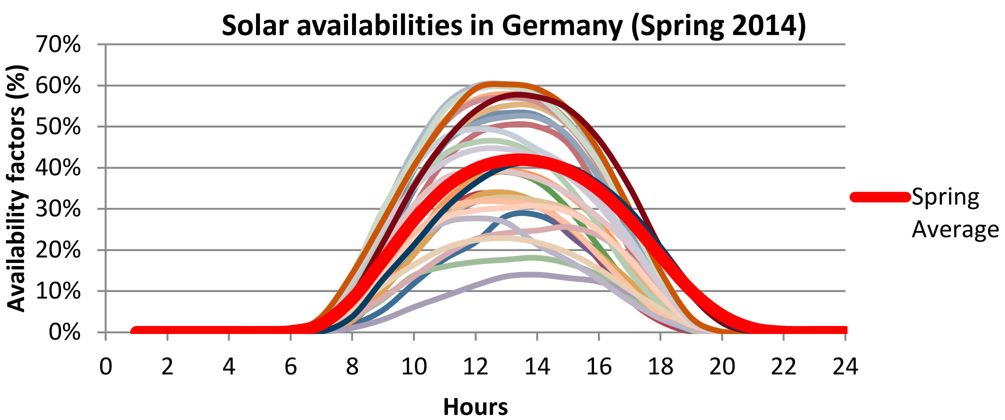


Figure 7-1: Generation schedule Germany, spring weekday 2050 (*CO2* scenario)



Source: (European Energy Exchange (EEX), 2014)

Figure 7-2: Average vs real solar availability factor in Germany (spring 2012)

Figure 7-2 shows the solar availabilities for the whole month of March 2012, as well as the average for spring season. The figure clearly shows the significant variations of solar PV generation between the days, which is not captured by CROSSTEM. This could lead to suboptimal investments as wind and solar availabilities are highly intermittent and unpredictable. The intermittency of solar and wind is also illustrated in Figure 7-3.

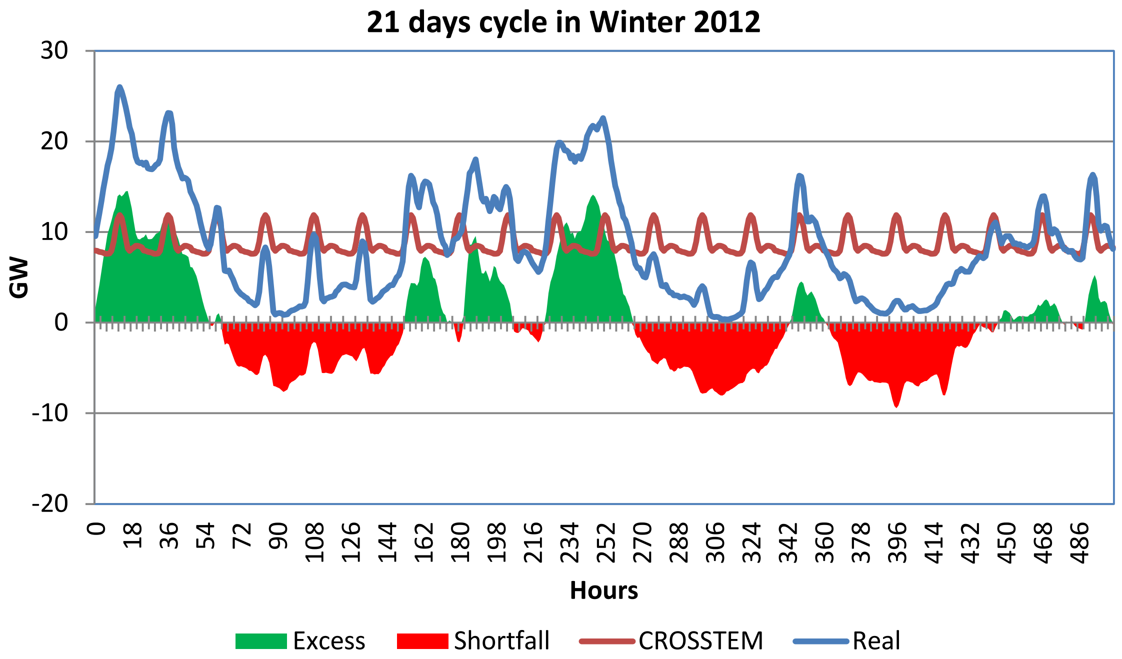


Figure 7-3: Real time wind & solar generation versus generation in CROSSTEM (Germany)

The blue line in Figure 7-3 shows the real solar and wind based electricity generation in Germany for three consecutive winter weeks in the year 2012. The red line shows the averaged solar and wind based electricity generation represented in CROSSTEM for winter. It becomes evident that the real time variations are very high, with days of extreme peaks interceded by periods of low generation. By averaging the intermittent generation over a season in CROSSTEM, the inherent assumption is that the reserve capacity, together with the flexible and storage technologies in the model can deal with these hourly variations in electricity output. This means that periods of excess generation (shown by the green region in Figure 7-3) can be stored and used during periods of low generation (red region in Figure 7-3), or alternatively, there are flexible electricity generation technologies (such as hydro or gas plants) that can reduce / increase their production following the residual load curve[48].

The CROSSTEM-***H****ourly* ***G****eneration* (CROSSTEM-HG) model was developed to test the validity of this assumption, i.e. are the storage and flexible electricity generation capacities generated by CROSSTEM sufficient to balance an electricity system with a high share of intermittent renewables. The CROSSTEM-HG model tries to analyse whether the installed capacity of CROSSTEM can cope with the variability of solar and wind generation, and if not, then what would be the additional storage capacities required to balance the system.

The next section will provide the methodology of the CROSSTEM-HG model, followed by results and conclusions from the analysis.

7.2 Methodology

CROSSTEM-HG aims to generate insights on the short-term intermittency issues of renewable resources (i.e. variability amongst days in a given season); hence it requires a time resolution that is high enough to capture these effects. However, in order to have a high time resolution, the capacity expansion aspect has to be limited to reduce the computational intensity. Hence a quasi "dispatch" model was developed, which does not focus on capacity planning anymore. This section details the important methodological characteristics in CROSSTEM-HG.

7.2.1 Time horizon and intra-annual time resolution

CROSSTEM-HG does not focus on long term capacity planning. Hence the time horizon has been restricted to one year.

The intra-annual resolution on the other hand is considerably increased in CROSSTEM-HG compared to the CROSSTEM model. The 8760 hours in the year are now represented via 1512 hourly timeslices (an hourly representation of three consecutive

[48] Residual load is the power demand after subtracting supply from intermittent renewables (Ueckerdt et al., 2015)

weeks in three seasons) as shown in Figure 7-4. While this timeslice resolution is still low compared to traditional dispatch models which have hourly or 15 minute resolutions (Deane et al., 2015; Schlecht et al., 2014b), this approach is a leap forward and the first of its kind application of the TIMES framework at this geographical and technological detail level to shed insights on integration of intermittent renewables.

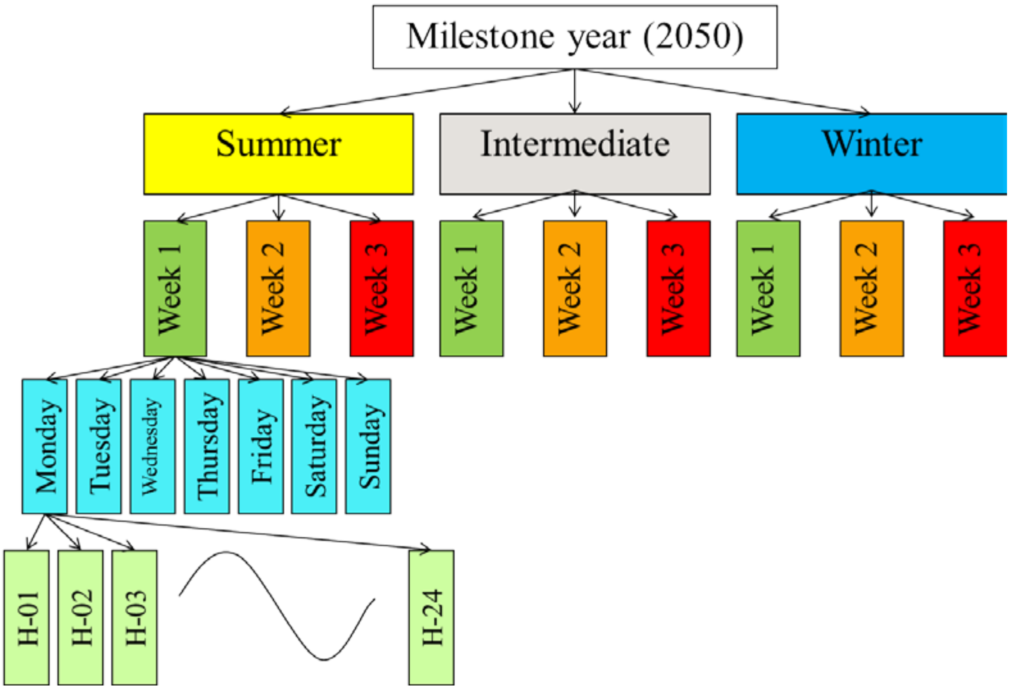


Figure 7-4: Intra-annual time resolution in CROSSTEM-HG

7.2.2 Electricity generation technologies

The installed capacity for CROSSTEM-HG is taken from CROSSTEM. In the analysis presented in this chapter, the capacity mix for the year 2050 from the climate change mitigation scenario ***(CO2)*** discussed in Chapter 5 has been used (see Table 7-1). These capacities are fixed, i.e. no capacity expansion is allowed in CROSSTEM-HG. Technical characteristics such as availability factors and efficiencies of the technologies are the same as those used for CROSSTEM and described in Chapter 3. Interconnector capacities between regions are also fixed from CROSSTEM, but the trade volumes among the five regions is not constrained. Trade volumes with the external "fringe" regions on the other hand are fixed from CROSSTEM. Annuities (i.e. capital costs) of technologies are not included, and the merit order of technologies is based on the operation and maintenance costs of the technologies and fuel costs.

Table 7-1: Capacities from CROSSTEM - *CO2* scenario for year 2050

Technology	Austria	France	Germany	Italy	Switzerland
Hydro (Dam)	4	17	1	6	4
Hydro (River)	6	10	6	10	9
Hydro (Pump)	3	3	7	8	3
Solar PV	17	111	133	123	10
Solar CSP	0	0	0	5	0
Wind Onshore	7	35	75	21	4
Wind Offshore	0	26	31	9	0
Other RES	1	14	12	6	1
Nuclear	0	52	0	0	0
Coal CCS	1	3	0	5	0
Coal	0	0	0	0	0
Gas CCS	2	4	17	4	3
Gas (Flex)	0	3	14	11	1
Gas (Base)	0	0	0	2	0
Battery	2	21	19	37	0

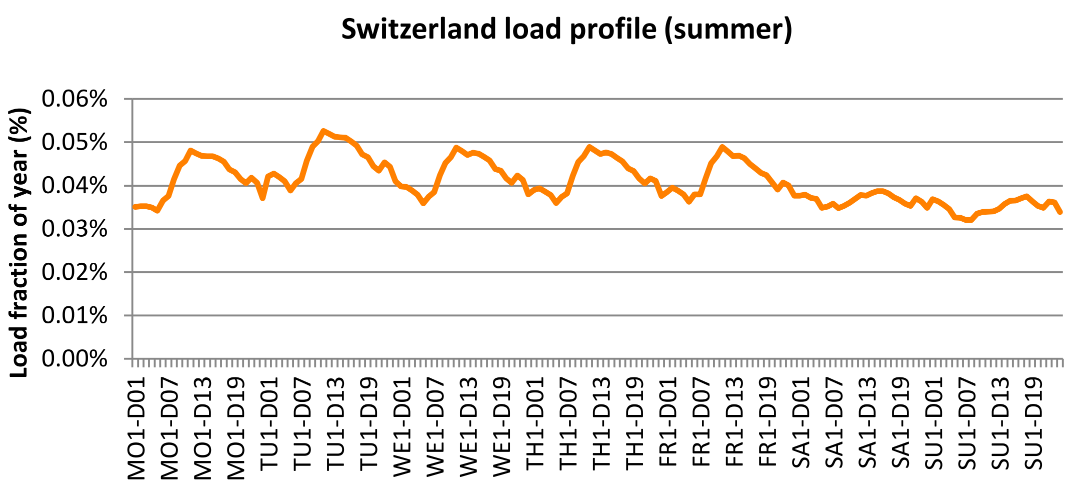
To enable the system to cope with supply and demand balancing, investment in three new technologies is allowed if the given CROSSTEM capacity mix cannot adequately satisfy the demand (see Table 7-2). There is a battery technology which can be used for hourly storage of electricity, a seasonal storage process which can be used for hourly, weekly and seasonal storage, and a flexible gas plant. The costs of the storage technologies are kept artificially high (see Table 7-2) to have the investment only if required. Techno-economic data from a lead-acid battery (flow battery) was used for the hourly storage technology (Bundesamt für Energie, 2013). For the seasonal storage technology, storage efficiencies and O&M costs of Compressed Air Energy Storage (CAES) was used (Bundesamt für Energie, 2013).

Table 7-2: New technologies for CROSSTEM-HG

Technology	Efficiency	Availability	Levelised Cost[49]
Hourly Storage (Battery)	85%	50%	20 Rp/kWh
Seasonal Storage	50%	50%	30 Rp/kWh
Flexible Gas plant	55%	66%	13 Rp/kWh

7.2.3 Electricity demand profile

The electricity demand load profiles are taken from (ENTSO-E, 2014) for the year 2010. Hourly load profiles are averaged for a week in each season, i.e. the three weeks in summer have identical load profiles. An example of the load profile for a summer week in Switzerland is shown in Figure 7-5. The load profile is kept static in the analysis presented in this chapter to focus solely on the uncertainty in solar and wind based electricity supply. However, such an analysis is incomplete without accounting for uncertainty in the electricity demand, and future analysis replace average profiles with randomly sampled load profiles.



Source: (ENTSO-E, 2015)

Figure 7-5: Switzerland load profile (summer)

[49] Levelised cost based on an electricity price of 15 Rp/kWh. Marginal costs in CROSSTEM-HG are between 8 – 20 Rp/kWh

7.2.4 Solar and wind availability profiles

The main purpose of the CROSSTEM-HG model is to analyse variability in solar and wind based electricity production and how to match it with the electricity demand, i.e. balancing the supply and demand on an hourly basis. In order to achieve this, solar and wind availability profiles for three consecutive weeks in each of the three seasons are randomly selected from real-time solar and wind electricity generation data from the year 2014. These actual electricity generation profiles were obtained from German and French Transmission System Operators (TSO) (50 hertz, 2015; Amprion, 2015; Réseau de transport d'électricité, 2012; Tennet(DE), 2015; Transnet BW, 2015). German wind and solar PV data was used for determining availabilities in Germany, Austria and Switzerland, while French data was used for France and Italy. An example of a three week profile for solar availabilities in summer for Germany is given in Figure 7-6. Each CROSSTEM-HG scenario, will have a randomly chosen solar and wind profile for each country. By repeated sampling and running of the model, some level of stochasticity is introduced in the analysis. For the scenario analysis presented in this chapter, each scenario is run with five random profiles to get an indication of the seasonal and hourly storage requirements.

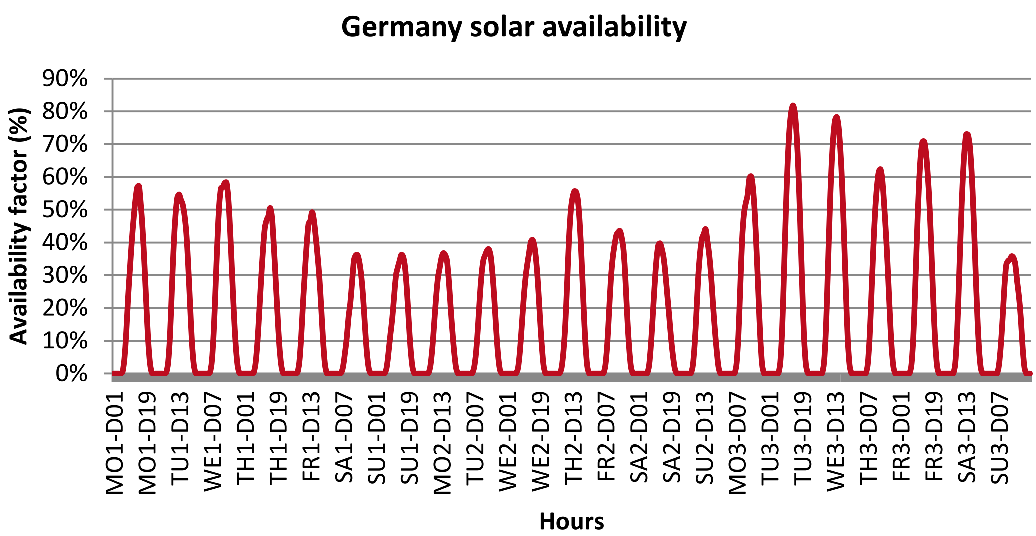


Figure 7-6: Solar PV availability factors in summer for Germany

It should be noted that the solar and wind profiles in each country is normalised to the corresponding seasonal average availability factors used in CROSSTEM, in order to maintain consistency between the two models. This implies that for a given installed capacity, the total electricity generation from solar or wind for a given season is the same for both models, but the generation profile varies between CROSSTEM and CROSSTEM-HG.

7.2.5 Ramping constraints

In the CROSSTEM model, technologies are assumed to start and shut down instantaneously, or be available constantly throughout the year. However, in real world operation, technologies have a start-up/shut-down time, as well as ramp up/down rates to vary the output. To reflect this, all the non-renewable technologies (everything except solar and wind) in CROSSTEM-HG have a ramping up/down rate, as well as a minimum stable operating level as described in Table 7-3. The ramping rates are expressed in percentage of capacity ramping per hour. For example, river hydro has a ramping rate of 11% per hour, meaning that it takes around 10 hours to completely shut down a plant running at maximum capacity, and vice versa. The values given in Table 7-3 are assumptions calculated from electricity generation curves of the Swiss electricity statistics (Bundesamt für Energie, 2014a). As the model represents technologies at an aggregated level rather than individual power plants, the ramping rates and minimum operation levels are estimated for the whole fleet of power plants. This is very difficult to estimate and there were no corresponding numbers in literature.

Table 7-3: Technology constraint in CROSSTEM-HG

Technology	Ramping rate	Minimum stable operation level
Hydro – River	11%	20%
Hydro – Dam	100%	5%
Nuclear	2%	40%
Coal/Coal CCS/Gas CCS	2%	40%
Biomass/Waste/Geothermal	5%	25%
Gas (Baseload)	15%	25%
Gas (Flexible)	100%	15%

The numbers given in the table above are initial assumptions, which need to be refined further in the future analysis.

7.3 Results

The results from the CROSSTEM-HG run for the ***CO2*** scenario indicate that there is an underestimation of both hourly and seasonal storage in CROSSTEM. The range of hourly and seasonal storage required to balance the system is given in Table 7-4.

Table 7-4: Hourly and seasonal storage in CROSSTEM-HG

Country	Battery Storage (TWh)	Seasonal Storage (TWh)
Austria	0 – 1.5	0
France	0 – 16	5 – 10
Germany	2 – 25	0 – 10
Italy	0 – 4.5	3 – 6
Switzerland	0 – 1.5	0
Total	2 – 49	8 – 26

In CROSSTEM, the amount of battery (hourly) storage requirement is around 10% of the total generation from IRES resources. All of this storage occurs at the diurnal level and the model did not find the need for seasonal storage. However in CROSSTEM-HG, the total battery storage required to balance the high fluctuations of solar and wind power is around 13% of the total output from the IRES technologies. The results from CROSSTEM-HG also indicate a need for seasonal storage, which amounts to around 1% of the total solar and wind output. All the storage options mentioned above are deployed in addition to pumped storage systems, which also provide hourly and weekly storages, and account for around 17% of the total storage system (Total storage system = Pump + Battery + Seasonal storage).

Figure 7-7 shows the dispatch schedule for Switzerland in a summer week in 2050. The figure clearly illustrates how Switzerland manages the intermittency of solar and wind with the flexibility of hydro power plants (both river and dam/pump) as well as electricity imports. Output from base load plants such as geothermal are also adjusted to accommodate solar PV generation.

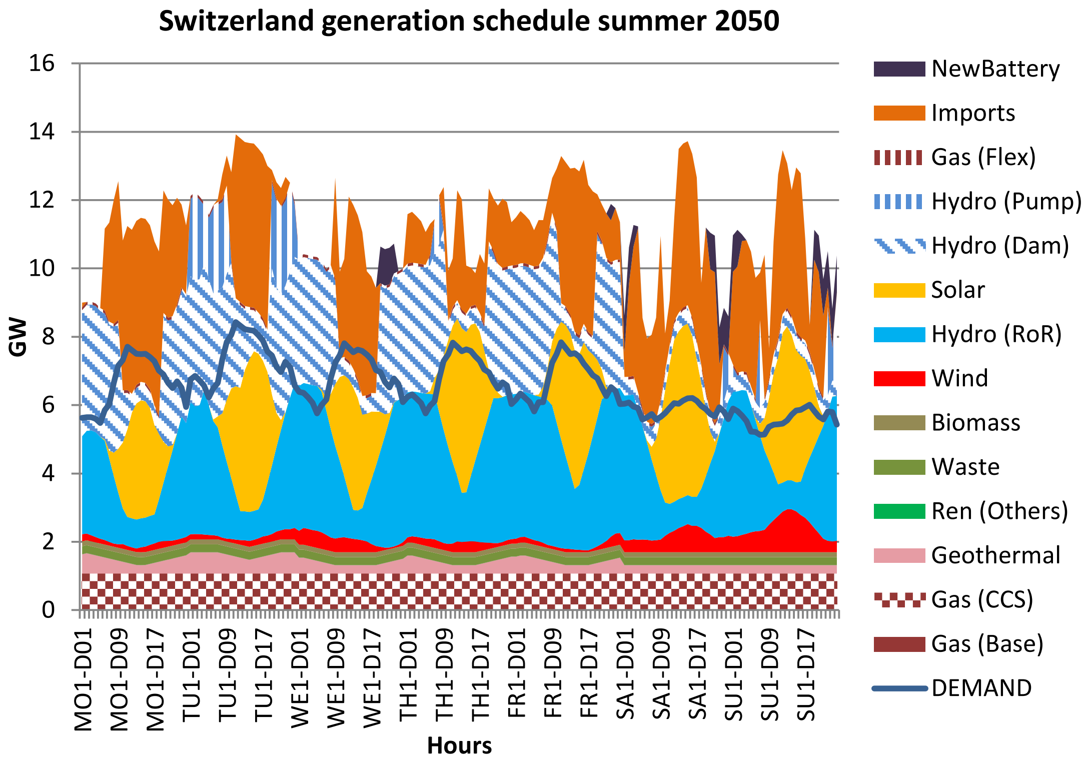


Figure 7-7: Switzerland generation schedule summer 2050

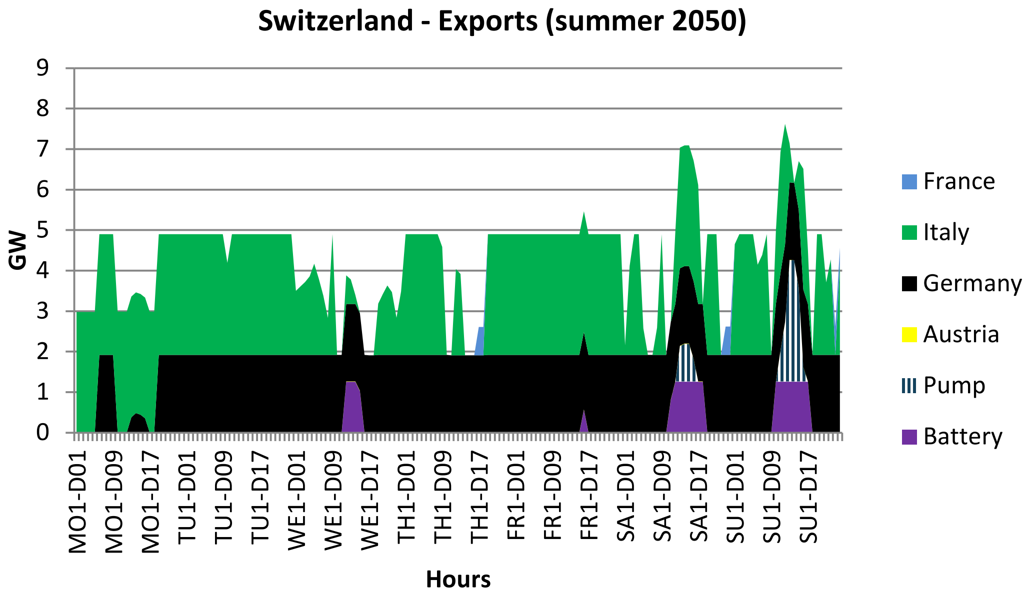


Figure 7-8: Switzerland exports in summer 2050

The excess supply of electricity (everything above the blue demand line in Figure 7-7) is either exported or stored, as shown in Figure 7-8. Electricity exports are primarily to Italy and Germany, whereas the imported electricity is mainly produced in France. Hence, Switzerland is a net exporter in summer, while Italy and Germany are net importers due to the lower output of wind turbines in summer. Electricity is stored in battery and pump storage systems during periods with high solar output, or when demand is low such as on weekends.

In the winter, Switzerland becomes a net electricity importer to meet its electricity demand, as shown in Figure 7-9. The net imports reach around 4 – 5 TWh, with most of the imports coming from France, Germany and Austria. While Germany was an electricity importer in summer, it becomes a net exporter of electricity in winter due to the higher outputs from wind based generation. Figure 7-10 shows the generation schedule in France for the same winter week. It can be observed that a substantial amount of electricity supply comes from the seasonal storage process (grey area in Figure 7-10), which was charged during high solar output days in summer. A similar trend is seen in Germany and Italy where it is cost-optimal to invest in seasonal storage (see Appendix D for generation schedules of other countries and seasons).

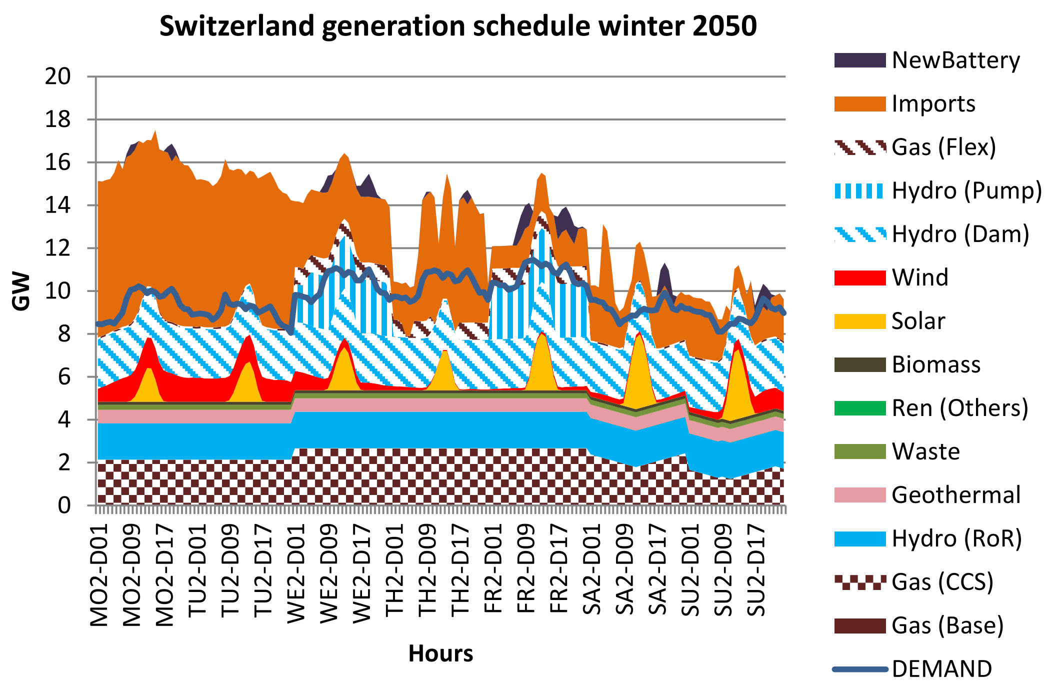


Figure 7-9: Switzerland generation schedule winter 2050

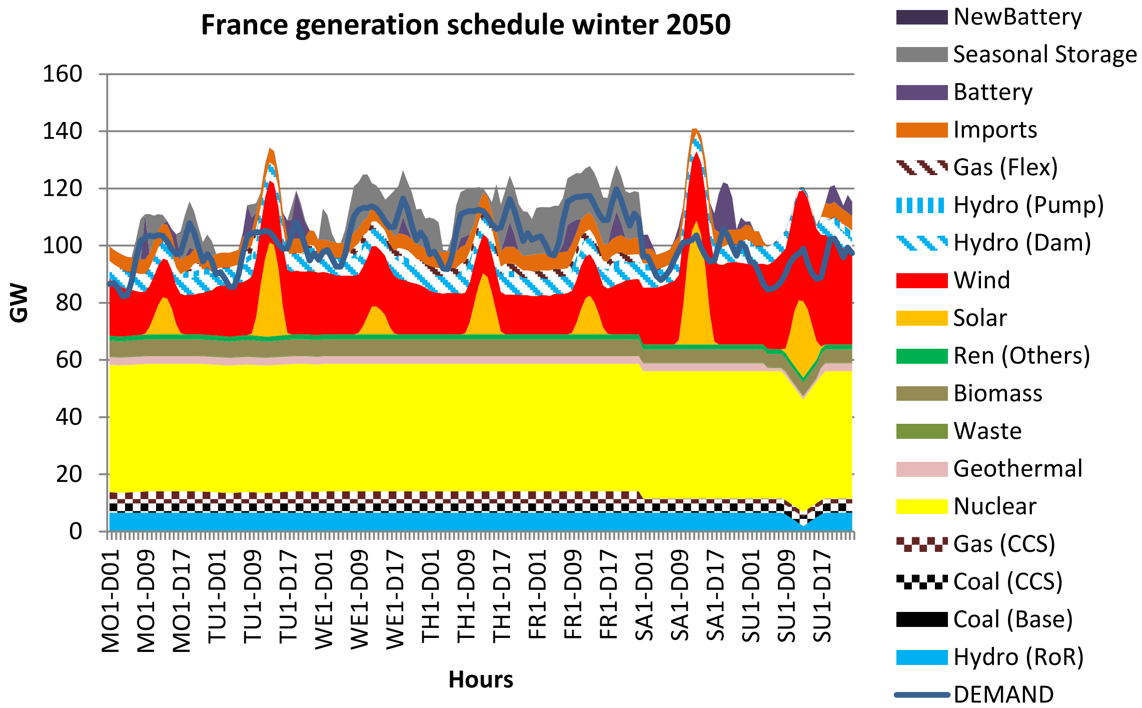


Figure 7-10: France generation schedule winter 2050

Although seasonal storage investments in CROSSTEM-HG are made in France, Germany and Italy, it does not necessarily imply that Switzerland does not require seasonal storage. As mentioned before, Switzerland is a net importer of electricity in winter, and relies on countries like France and Germany for imported electricity. In other words, while Switzerland benefits from seasonal storage investments in neighbouring countries, it makes Switzerland dependant on these countries in high demand periods in winter. Alternatively, seasonal storage investments could be made in Switzerland which would mean higher imports during summer to charge the seasonal storage units, and discharging them in winter, thereby reducing the import dependence on neighbouring countries in winter.

7.4 Conclusions

The analysis with the CROSSTEM-HG model has shown that CROSSTEM underestimates the necessary storage capacities to manage an electricity system with an intermittent renewable electricity share of 50% (***CO2*** scenario). Both hourly and seasonal storages are underrepresented in CROSSTEM, implying that despite having a higher number of timeslices (288), capacity expansion models such as CROSSTEM still create sub-optimal investments in storage or flexible supply options. Additional hourly storage requirements are as high as 50 TWh for all CROSSTEM countries together, amounting to around 3% of the total intermittent generation. Seasonal storage requirements are underestimated between 8 – 26 TWh in CROSSTEM, or up to 1% of the total intermittent generation.

Further work needs to be done on the model to improve the methodology and results. Firstly, more elements of the unit commitment problem can be included, such as minimum online and offline times, start-up/shut-down associated costs, part load efficiency, etc. Key input assumptions such as ramping rates and minimum stable operation levels have also to be refined. The modelling of storage technologies (both battery and seasonal storage) is simplified, and does not take into account operational characteristics of batteries such as degradation due to charge cycles, depth of discharge and discharge rates etc. Viability of alternate storage technologies for seasonal storage such as power to gas also need to be explored further. Problems with fringe regions, which have been discussed in Chapter 5 and Chapter 6, persist for CROSSTEM-HG as well. Expanding the geographical boundaries to include wider EU regions as done with EUSTEM (Chapter 6) could be an option for the hourly generation model as well.

Refinements can also be made to improve the stochastic aspects of the model. Increasing the number of runs with random solar and wind profiles in a Monte Carlo setting would lead to more robust results, and help to quantify the uncertainties. Having probability distributions associated with various solar and wind profiles would further advance the analysis. The eventual aim of CROSSTEM-HG should be to feedback the insights to CROSSTEM to create a complete framework which effectively integrates dispatch capabilities in a capacity planning framework.

8 CONCLUSIONS AND OUTLOOK

The electricity sector of Switzerland and Europe is on the verge of an unprecedented transformation, and complex modelling frameworks are required to assess the impacts of energy and climate change policies on the sector's future configuration. The overall aim of this dissertation was to generate insights into possible transition pathways for the Swiss electricity system in the medium- to long-term future, under varying boundary conditions in Europe in general, and the neighbouring countries of Switzerland, in particular. The thesis analyses various cost-optimal pathways to achieve a decarbonised power sector for Europe by 2050, and the technical, environmental, and economic implications of choosing various low-carbon technologies to achieve climate mitigation goals. A series of scenarios were analysed using multiple models to capture the various uncertainties and generate clear insights into issues regarding climate mitigation targets, electricity trade, carbon capture and storage (CCS), electricity storage and supply security issues for Switzerland and its neighbouring regions.

This chapter presents the key conclusions from the thesis, as well as an outlook on future work that can be done to improve the modelling frameworks. The conclusions are divided into two sections: (a) methodological conclusions which highlight the advantages and disadvantages of the different models discussed in Chapters 4, 6 and 7; and (b) general policy conclusions based on the scenario analysis discussed in Chapters

4, 5, 6 and 7.

8.1 Methodological conclusions

8.1.1 Multi region models versus single region models

The main motivation for developing the CROSSTEM framework was based on the premise that single region models of Switzerland such as the Swiss TIMES electricity model (STEM-E), and others discussed in Chapter 2, did not capture impacts of developments in neighbouring countries on the Swiss electricity system. By accounting for the electricity system developments in neighbouring regions, CROSSTEM generates alternative insights on the cost-optimal deployment of technologies.

Chapter 4 compares the results from CROSSTEM with CROSSTEM-CH (a variant of the CROSSTEM model obtained by running it in single region mode[50]). The analysis demonstrated that CROSSTEM-CH led to suboptimal investment decisions compared to CROSSTEM due to the assumption of dispatchable fringe regions for the electricity markets of neighbouring countries in CROSSTEM-CH. Penetrations of renewable technologies, such as solar PV, are overestimated, and the requirement of flexible backup generation technologies, such as gas plants, are underestimated by the single region CROSSTEM-CH model. As a result, the total system costs required for the transition to a future electricity system are underestimated in CROSSTEM-CH. For example, the cumulative system cost in the given time horizon (2015 – 2050), for a reference scenario (see *Baseline* scenario in Chapter 4), is around CHF 35 billion lower in CROSSTEM-CH compared to CROSSTEM (or around 15% lower than cumulative costs in CROSSTEM). The average electricity generation cost for Switzerland in CROSSTEM for the year 2050 is around 70% higher than in CROSSTEM-CH.

While CROSSTEM highlights the impact of the neighbouring countries on the Swiss electricity system, it ignores the influence of wider EU markets. Electricity trade between neighbouring countries of Switzerland and wider EU markets are exogenously

[50] The CROSSTEM-CH model is analogous to STEM-E, with exogenous price assumptions for electricity imports and exports.

defined, and this assumption results in secondary effects on the Swiss electricity system. The effect was initially highlighted by a sensitivity analysis in Chapter 5. The phenomenon of "load dumping"[51], which was first discussed in Chapter 4 with respect to the single region CROSSTEM-CH model, is shifted to the neighbouring countries in CROSSTEM.

In order to analyse the impacts of the wider EU markets on Switzerland, the EUSTEM model was developed. EUSTEM is a geographical extension of CROSSTEM, accounting for electricity markets of erstwhile fringe regions in CROSSTEM. The analysis with EUSTEM in Chapter 6 showed that the cost-optimal penetration of renewable technologies in Switzerland is overestimated in CROSSTEM, and the corresponding storage and flexible backup generation technologies required to balance the system are underrepresented. For example, in a decarbonisation scenario (see ***CO2*** scenario in Chapter 5, 6), solar PV penetration in Switzerland for the year 2050 is 50% lower in EUSTEM than in CROSSTEM. EUSTEM also indicates the requirement for storage capacities, with around 2 GW of additional battery storage required in Switzerland by 2050, despite a lower penetration of intermittent renewable technologies.

The various scenarios analysed in Chapter 4, 5 and 6 demonstrated that having a multi-region model with wider EU markets represented is important to understand the evolution of the Swiss electricity system. However, the downside of moving to bigger models is computational complexity. The average time for running a scenario in CROSSTEM-CH is around 5 minutes, for CROSSTEM around 1 hour and for EUSTEM between 10 – 15 hours. Improvements in model structure and fine-tuning of solver parameters need to be explored to reduce this.

8.1.2 CROSSTEM-HG versus CROSSTEM

The representation of higher intra-annual time resolution is one of the major strengths of

[51] "Load dumping" is a term used to describe the phenomenon of dumping excess electricity to fringe regions in the model without any knowledge of their markets. By not representing electricity markets in such regions, excess electricity is exported (or "dumped") to these regions while generating trade revenue at the same time.

the CROSSTEM model compared to other electricity system models of Switzerland described in Chapter 2. By combining certain dispatch aspects into long-term capacity expansion models, better insights were obtained, particularly regarding the penetration of intermittent renewable technologies, such as solar PV and wind. However, CROSSTEM cannot capture short-term intermittencies of such technologies due to the limited number of timeslices used to represent a year. The CROSSTEM-HG model is a preliminary approach to help address this limitation.

The analysis with the CROSSTEM-HG model in Chapter 7 demonstrated that by oversimplifying the solar and wind intermittencies, CROSSTEM underestimated the necessary storage or flexible generation capabilities required to manage an electricity system with an intermittent renewable electricity share of more than 50% (***CO2*** scenario). Both hourly and seasonal storages are underrepresented in CROSSTEM, implying that despite having a higher number of timeslices (288), capacity expansion models such as CROSSTEM still result in sub-optimal investment decisions, especially for electricity systems with a high share of intermittent renewables.

As mentioned before, CROSSTEM-HG is an initial attempt to address the intermittency issue of renewables in long-term models. The model still requires further refinements in its dispatch and stochastic aspects, as well as in its data. The eventual aim of CROSSTEM-HG is to feedback its insights to CROSSTEM to create a complete framework which effectively integrates dispatch capabilities in a capacity planning framework.

8.1.3 ELECTRA-CH versus CROSSTEM-CH

The ELECTRA project successfully coupled a top-down economic model (GENESwIS) with a bottom-up electricity system model (CROSSTEM-CH) of Switzerland. The representative scenarios analysed with the framework demonstrated the capabilities of the coupled model, and highlighted its superiority over the respective standalone versions (see Chapter 4). Coupling the CROSSTEM-CH model with a CGE model (GENESwIS) introduced electricity demand feedbacks to a previously inelastic demand. For example, in the ELECTRA-CH framework, increasing electricity prices in CROSSTEM-CH induced substitution of electricity with other energy carriers in

GENESwIS and reduced the electricity demand, thereby providing endogenous electricity demand pathways. Besides demand feedbacks, the coupled framework also incorporated sectoral price feedbacks from GENESwIS to CROSSTEM-CH, thereby quantifying impacts of variations in labour or materials prices in GENESwiS on investment or operational costs of power plants in CROSSTEM-CH.

In conclusion, the new coupled framework combined the best aspects of bottom-up and top-down components, greatly improving the understanding of supply and demand interactions.

8.2 General Conclusions

This section discusses the technical, economic and policy implications of various scenarios on the Swiss electricity system, providing a summary of the conclusions drawn in Chapter 5, 6 and 7.

8.2.1 Nuclear Phase-out

The implications of nuclear phase-out policies in Switzerland and neighbouring countries (Germany and France) are discussed in detail in Chapter 5. The analysis concludes that in the absence of stringent climate change mitigation targets, natural gas-based generation combined with electricity imports is the cost-optimal technology choice for Switzerland. Cost of electricity imports to Switzerland increases due to the nuclear phase-out policies in Germany and France, which reduces the final share of imports to around 6% of the total demand by 2050, compared to more than 10% in a scenario without the nuclear phase-out (***Least Cost***).

The cumulative total system cost of an electricity system without nuclear in Switzerland is estimated to be around CHF 300 billion, which is close to CHF 40 billion higher than in the ***Least Cost*** scenario. The average electricity generation cost in 2050 is estimated to be around 45% higher than in 2010.

8.2.2 Decarbonization of power sector

The transition pathway to a decarbonised future Swiss and European electricity market is described in Chapter 5 and 6. The analysis showed that the cost-optimal way to reduce emissions in the European power system is via increased co-operation and electricity trade between the regions. Applying the emission reduction targets on an EU-level rather than on a country-level improved the utilisation of renewable and CCS storage potentials in the different countries.

To reduce CO_2 emissions in line with European low-carbon roadmap targets (95% CO_2 reduction by 2050 compared to 1990 levels), investments in gas CCS plants is cost-effective for Switzerland, provided that CCS technology becomes available and socially acceptable in the future. Investments in gas CCS technology allow Switzerland to be a net electricity exporter in the long-term. The cumulative total system costs for Switzerland in such a scenario is around CHF 300 billion, similar to the reference nuclear phase-out scenario (***NoNUC***), largely thanks to the surplus net trade revenue. However, the combined cost for decarbonising the electricity system of Switzerland and its four neighbouring countries is around CHF 980 billion higher than the reference scenario (***NoNUC***). An electricity system with a high share of gas CCS plants in Switzerland increases the domestic CO_2 emissions by almost 50% compared to 2010 levels.

To reduce the emissions domestically (i.e., by applying a national CO_2 emission cap on each country), Switzerland would require substantial electricity imports as domestic renewable potentials are insufficient to meet the high electricity demands assumed in the current analysis. By 2050, around a fifth of the electricity demand has to be imported, implying that Switzerland has to offset CO_2 emissions in neighbouring regions. This also results in additional costs, with cumulative system costs for Switzerland reaching around CHF 336 billion, approximately 12% higher than in a scenario with EU-wide emission caps.

Meeting the ambitious climate targets is challenging, and highly sensitive to assumptions regarding renewable potentials, CCS storage potentials, and availability of nuclear power. The average electricity generation costs in 2050 are 20 – 120% higher with respect to 2010, depending on the scenario assumptions.

8.2.3 Supply security in Switzerland

Net electricity generation self-sufficiency (i.e., not relying on net annual electricity imports), is one of the key questions that has been discussed in this thesis, as well as by other study groups. Three out of the four supply scenario variants of the Swiss Energy strategy assume self-sufficiency in electricity supply (PROGNOS AG, 2012). While energy-independence is desirable from a political point of view, many experts point out that self-sufficiency in electricity generation makes little economic or ecological sense, especially in a future electricity market with a high integration of renewable energy sources (Rüegg, 2014). Results from CROSSTEM converge to similar conclusions.

The analysis has shown that enforcing a self-sufficiency constraint for Switzerland increases the electricity generation costs by 5 – 30%, if the remaining boundary conditions are kept constant. The analysis also showed that in order for Switzerland and its neighbouring countries to become self-sufficient while adhering to their national CO_2 emission caps, the electricity demands have to be reduced, which implies higher costs in other sectors, such as energy efficiency measures and demand-side management.

8.3 Outlook to future work

Within the scope of this dissertation, a series of “what-if” scenarios have been analysed, illustrating possible transition pathways for a future Swiss electricity system in conjunction with developments in neighbouring countries and wider EU markets. Due to limitations in time, there were certain areas that could not be analysed in-depth. These areas provide a good scope for future research, and are described in the following subsections.

8.3.1 Refinement of EUSTEM

From the conclusions drawn from this PhD thesis, it has become clear that the EUSTEM model is necessary for a consistent analysis of the future Swiss electricity system. By including the whole European electricity market, EUSTEM avoids some of the limitations of CROSSTEM such as “load dumping” with fringe electricity markets, while at the same time representing impacts of developments in wider EU regions on Switzerland. The model was developed towards the end of the PhD, and needs further refinements to increase its robustness. For instance, the application of energy and environmental policies in wider EU markets need to be improved, as only major nuclear policies were included in the analysis presented in this thesis.

There is considerable scope for other upgrades to the EUSTEM model which would provide additional insights. Some of these are discussed in the following subsections.

8.3.1.1 Representation of the Transmission and Distribution (T&D) grid

One of the main limitations of CROSSTEM, as well as EUSTEM, is the absence of a detailed T&D network within the regions (i.e., countries are modelled as "copper plate" regions). This can result in sub-optimal investment decisions, as the areas with high resources of electricity supply may not necessarily coincide with areas of high electricity demand. For instance, conditions for wind-based generation are ideal in the north of Germany, with around 80% of Germany's wind parks situated in the northern states of the country (Bundesministerium für Wirtschaft und Energie, 2011). However, a considerable amount of the electricity demand is in the industry rich southern states of Germany, which raises important questions regarding transmission constraints within the country, and consequently interconnector capacities with neighbouring regions (Weigt et al., 2010). Hence, a better representation of the T&D grid in EUSTEM could generate additional insights with respect to electricity trade between regions.

On the other hand, the inclusion of T&D grids could also pave the way for representing decentralised production options, which are not considered in EUSTEM. There are other projects within the Energy Economics Group at PSI that explore decentralised production options for Switzerland, such as the "CHP Swarm" (Panos et al., 2015) and "IDEAS4cities" (Yazdanie & Densing, 2015) projects. Methodologies from these projects could be integrated into the EUSTEM model.

8.3.1.2 Optimization of Swiss electricity system

The EUSTEM model provides a cost-optimal transition of the whole European electricity system, i.e., it does not optimize each country individually. As the share of Swiss electricity production is comparatively small with respect to the whole of Europe[52], the results obtained from EUSTEM, although optimal for Europe, may not represent ideal solutions for Switzerland. Future work could be done to change the

[52] Share of the Swiss electricity demand and installed capacity is around 2% in EUSTEM

objective function in the model in order to optimise the solution for Switzerland. However, such an analysis should consider the implications on neighbouring countries.

8.3.2 Improvement of the CROSSTEM-HG model

Chapter 7 highlighted the limitations of CROSSTEM in addressing short-term variability issues of highly intermittent renewable technologies, such as solar PV and wind. CROSSTEM-HG was developed to address this limitation by analysing the supply – demand balance of CROSSTEM capacities under varying solar and wind availabilities. However, CROSSTEM-HG is only the first step in integrating high resolution dispatch capabilities into long-term capacity expansion models.

The aim of developing a quasi "dispatch" model using a capacity expansion framework like TIMES is to facilitate its integration into models like CROSSTEM, which uses the same framework for long-term planning. By linking the CROSSTEM-HG model to CROSSTEM via a hard-coupling process, insights from CROSSTEM-HG can be used in the capacity expansion decision process in CROSSTEM. Such a coupled framework would provide better insights into the long-term transition scenarios, particularly for scenarios with a high share of variable renewables.

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*Cover page image taken from http://www.iqagroup.co.uk/sectors/power/

APPENDICES

APPENDIX A - COUNTRY SPECIFIC INPUT DATA

This section contains the input assumptions used in the CROSSTEM model for chapters 4 and 5.

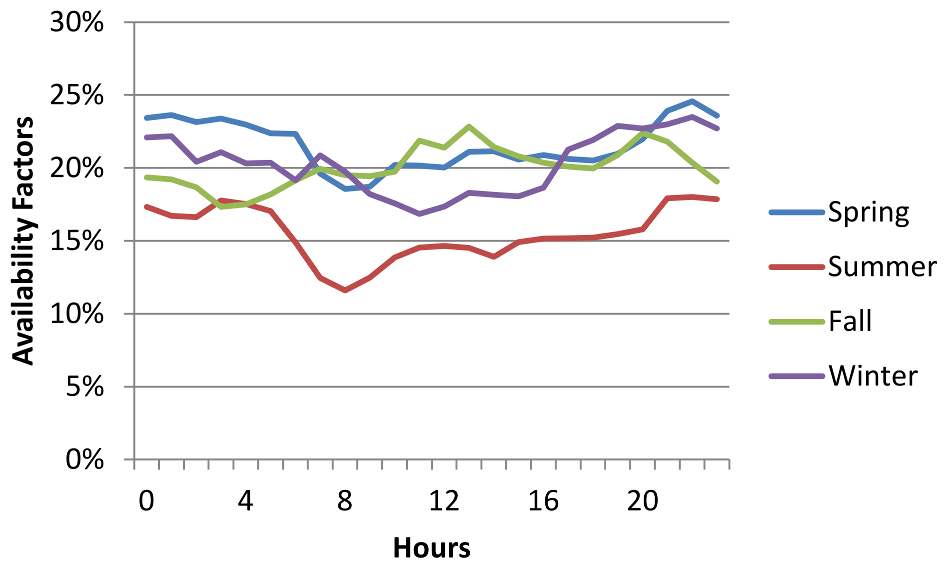
Austria

Table A 1: Austria - Existing Technology & model calibration (2010)

Technology Description	Stock capacity (GW)	Production (PJ)	Eff (%)	AF (%)	Peak contribution
Hydro (River)	5.7	109	80%	63%	90%
Hydro (Dam)	4.3	29	80%	25%	90%
Pump hydro	3	12	70%	17%	100%
Solar: PV	0.1	0.3	100%	11%	0%
Wind: Onshore	1	7	100%	24%	0%
Geothermal	0.001	0.004	100%	23%	50%
Biogas	0.4	3	36%	26%	30%
Wood/Biomass	0.8	13	21%	47%	90%
Waste Incinerator	0.6	3	16%	28%	30%
Coal: SCPC	1.6	24	41%	63%	90%
Gas: GTCC Base load	2.4	27	58%	80%	100%
Gas: GTCC flexible load	1.6	24	39%	48%	100%
Oil Engine	0.3	5	26%	77%	100%

Source: BMLFUW 2009; ENTSO-E; OECD iLibrary.

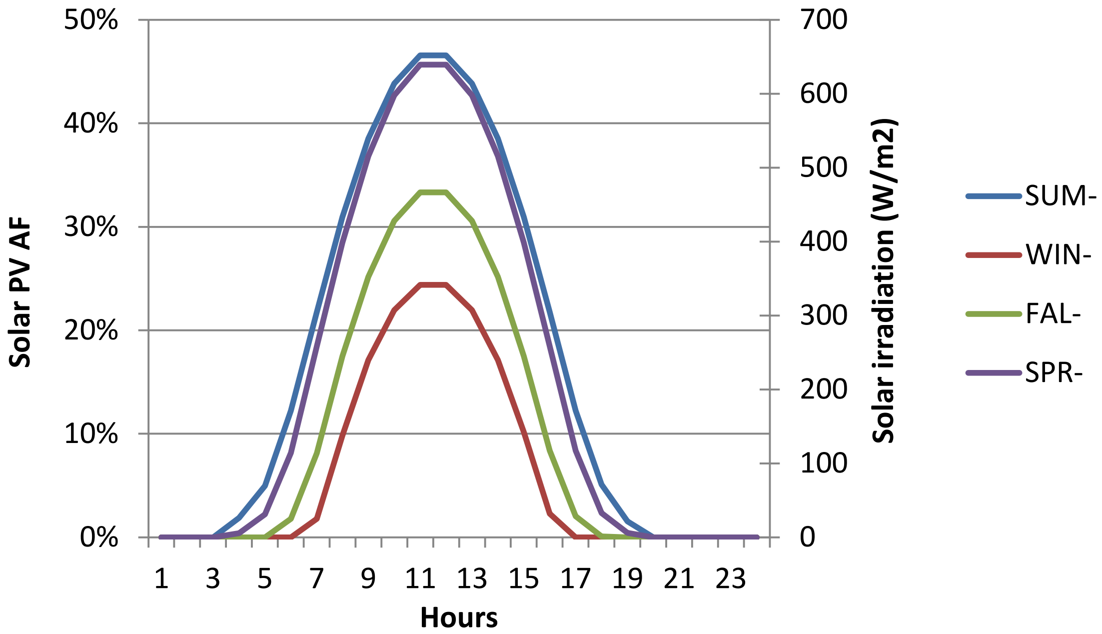
Wind availability factor



Source: Austrian Power Grid 2014.

Figure A 1: Austria - Wind (onshore) availability factor

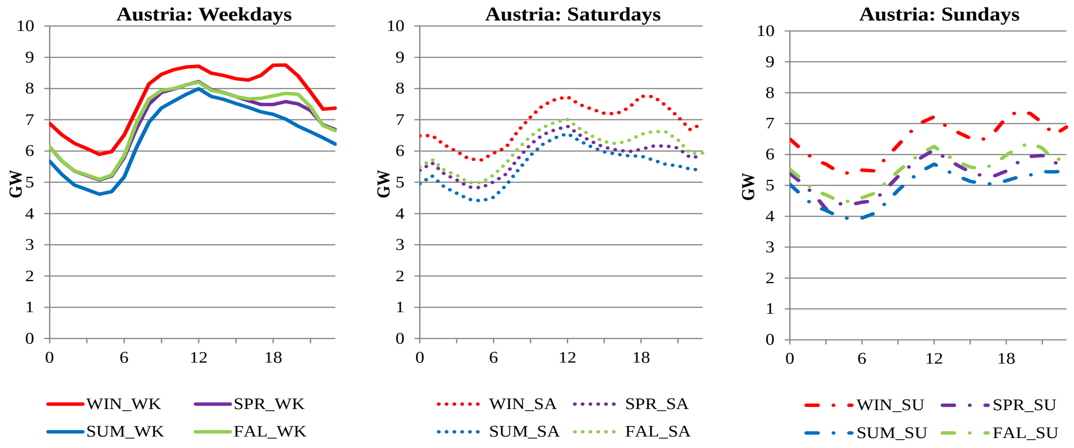
Solar availability factor



Source: JRC 2013.

Figure A 2: Austria - Solar availability factor (Vienna)

Electricity demand profiles



Source: ENTSO-E 2015.

Figure A 3: Austria - Electricity load profiles (2010)

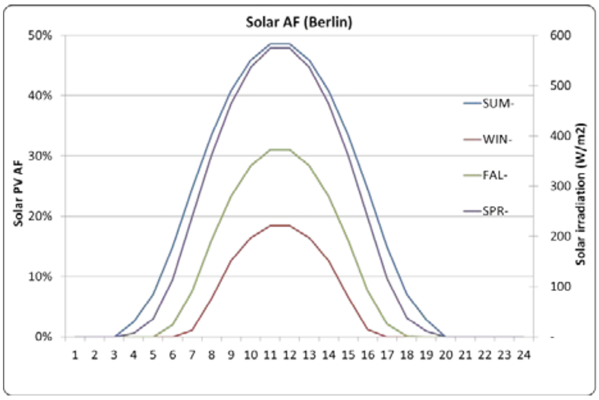
Germany

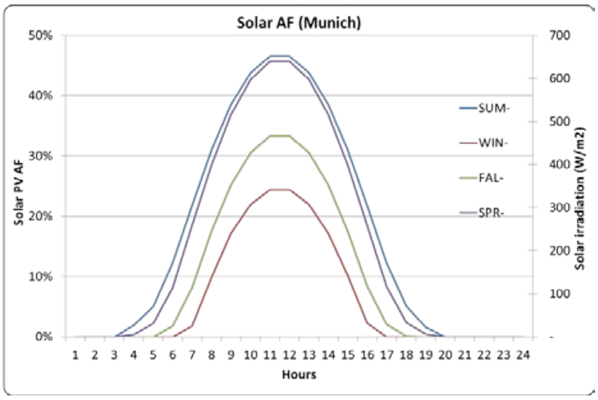
Table A 2: Germany Existing Technology & model calibration (2010)

Technology Description	Stock capacity (GW)	Production (PJ)	Eff (%)	AF (%)	Peak contribution
Hydro (River)	5.1	72	80%	45%	90%
Hydro (Dam)	0.6	3	80%	17%	90%
Pump hydro	6.8	23	74%	19%	100%
Solar: PV	21.3	42	100%	12%	0%
Wind: Onshore	27.2	136	100%	21%	0%
Geothermal	0.008	0.1	100%	23%	50%
Biogas	4.8	106	53%	80%	30%
Wood/Biomass	6.2	73	40%	46%	90%
Waste Incinerator	1.7	17	19%	39%	30%
Nuclear	23.5	506	33%	85%	100%
Lignite: SCPC	22.7	525	38%	83%	90%
Coal: SCPC	30.2	421	41%	55%	90%
Gas: GTCC Base load	7.2	186	58%	82%	100%
Gas: GTCC flexible load	16.6	124	42%	44%	100%
Oil Engine	5.9	30	43%	24%	100%

Source: BWE 2011; ENTSO-E; OECD iLibrary.

Solar availability factors

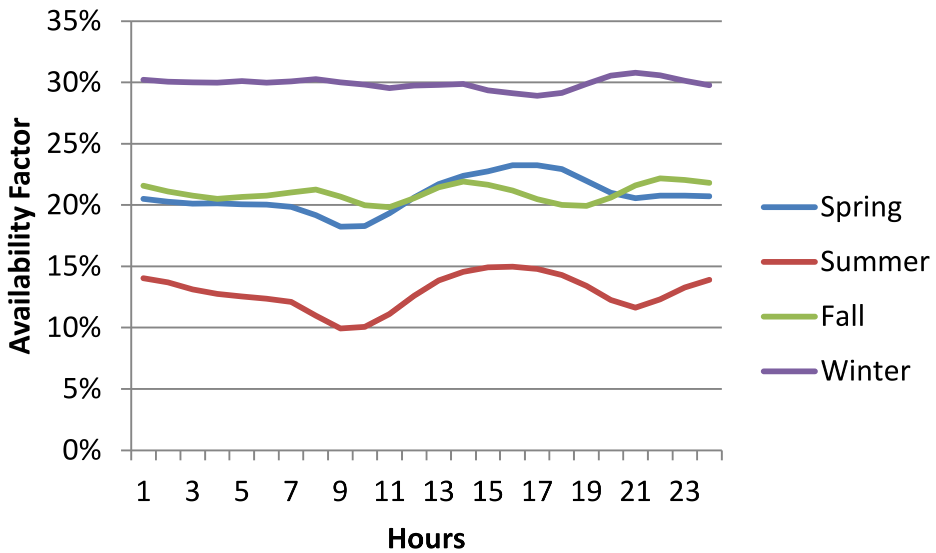




Source: JRC 2013.

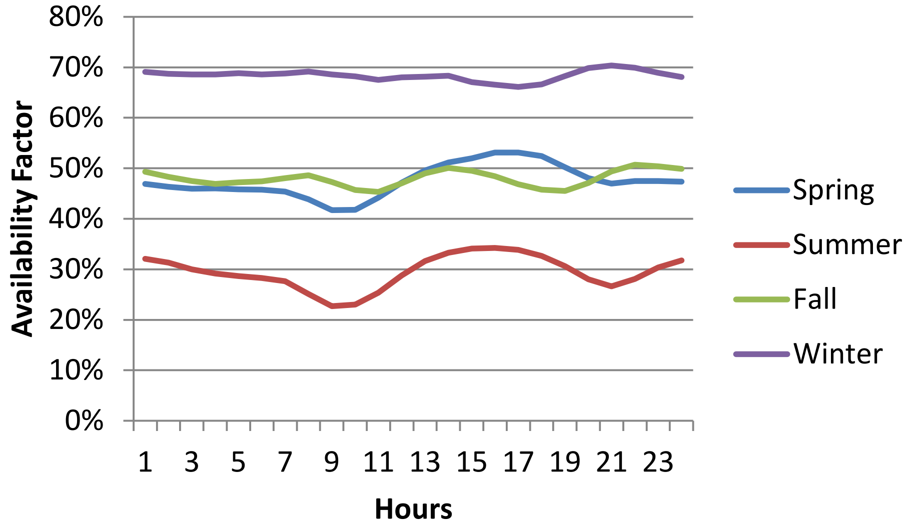
Figure A 4: Germany - Solar Availability factors (Berlin & Munich)

Wind availability factors



Source: European Energy Exchange, Transparency reports 2014

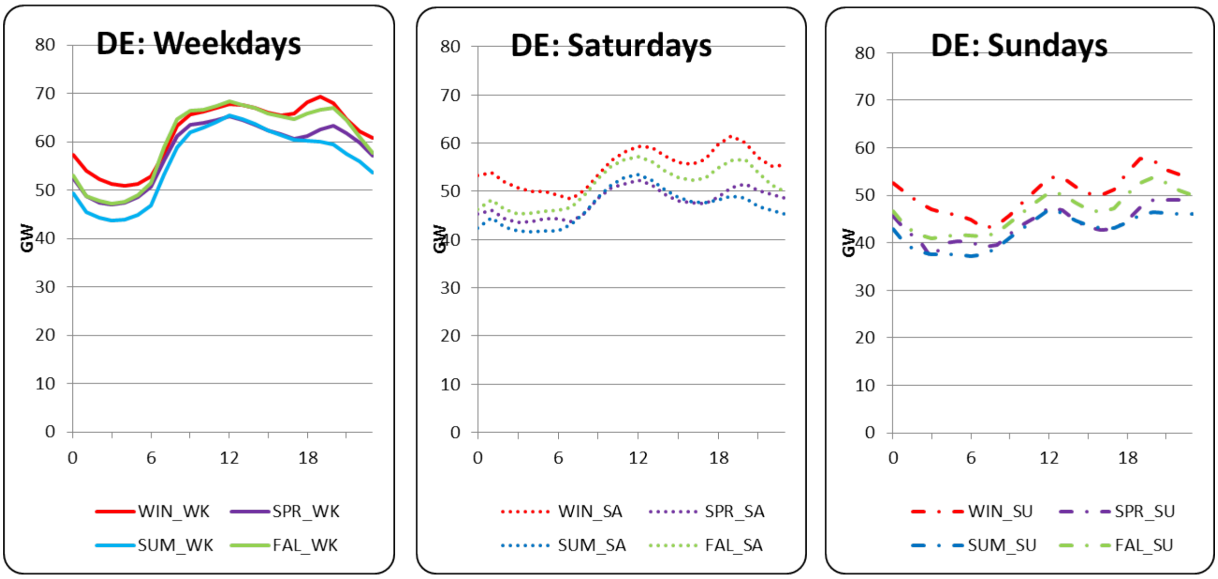
Figure A 5: Germany - Wind availability factor (onshore)



Source: European Energy Exchange, Transparancy reports, 2014.

Figure A 6: Germany - Wind availability factor (offshore)

Electricity demand profiles



Source: ENTSO-E.

Figure A 7: Germany - Electricity load profiles (2010)

France

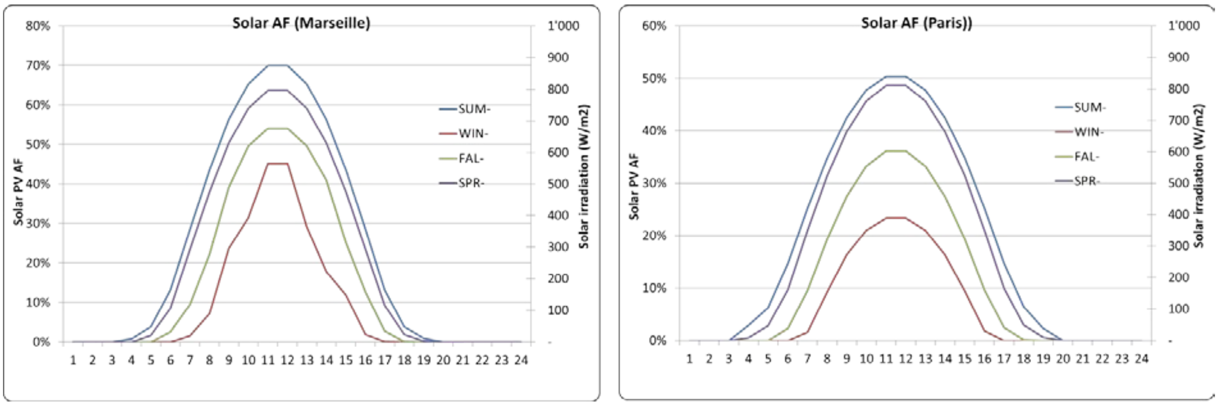
Existing technology

Table A 3: France - Existing Technology & model calibration (2010)

Technology Description	Stock capacity (GW)	Production (PJ)	Eff (%)	AF (%)	Peak contribution
Hydro (River)	8.5	122	80%	45%	90%
Hydro (Dam)	13.9	103	80%	24%	100%
Pump hydro	1.8	20	71%	36%	100%
Solar: PV	1.0	2	100%	15%	0%
Wind: Onshore	5.9	36	100%	22%	0%
Tide	0.24	2	100%	27%	0%
Biogas	0.62	4	31%	20%	30%
Wood/Biomass	1.2	6	40%	15%	30%
Waste Incinerator	2.4	15	20%	20%	30%
Nuclear	63.1	1543	35%	82%	100%
Coal: SCPC	3.5	95	40%	85%	90%
Gas: GTCC flexible load	9.5	86	31%	40%	100%
Oil Engine	10.4	21	21%	40%	100%

Source: RTE, 2010; ENTSO-E; OECD iLibrary.

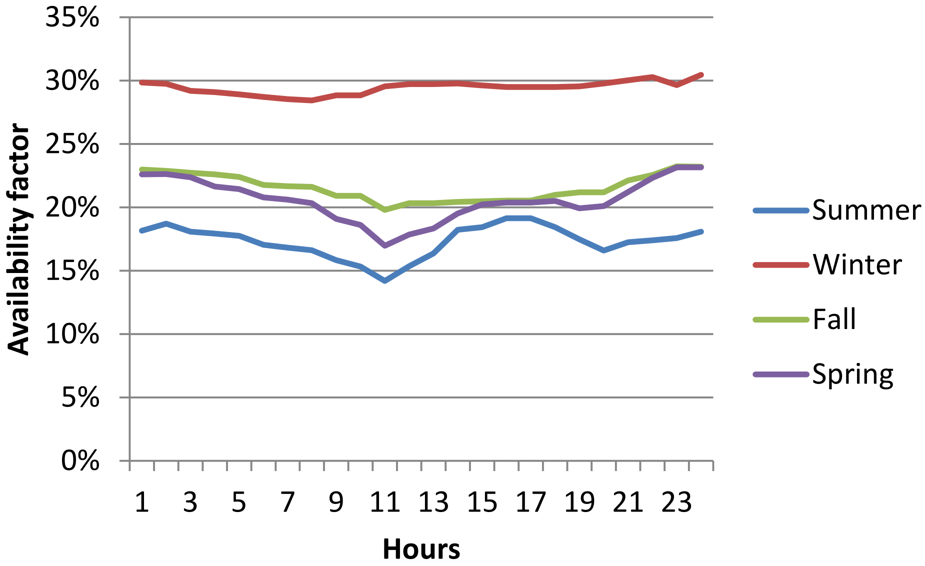
Solar availability factors



Source: JRC, 2013.

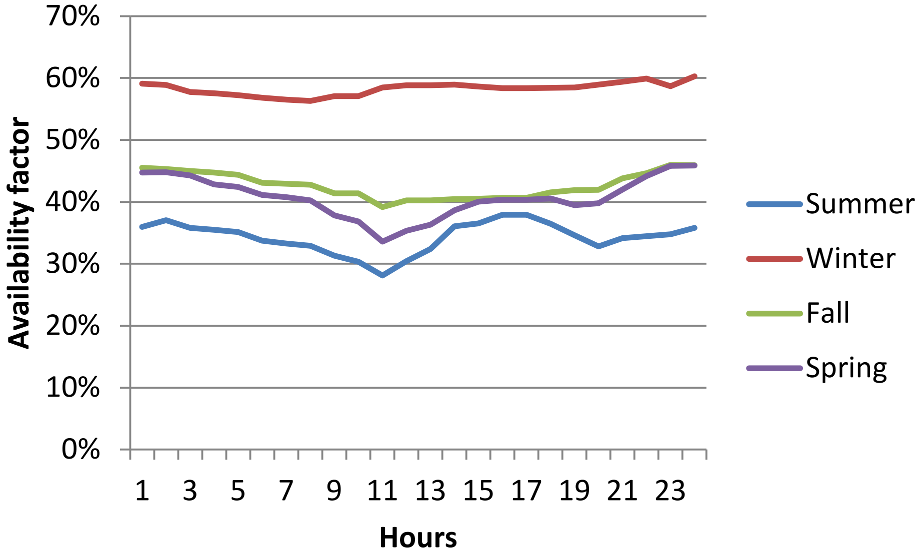
Figure A 8: France - Solar availability factors (Marseille & Paris)

Wind availability factors



Source: Réseau de transport d'électricité 2012.

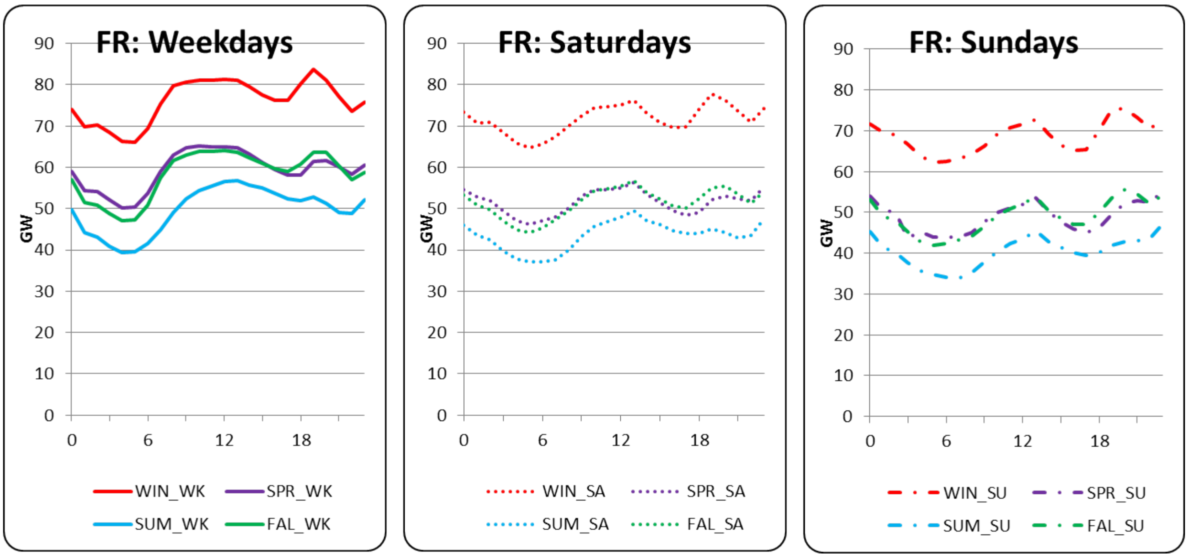
Figure A 9: France - Wind availability factor (onshore)



Source: Réseau de transport d'électricité 2012.

Figure A 10: France - Wind availability factor (offshore)

Electricity demand profiles



Source: ENTSO-E.

Figure A 11: France - Electricity load profiles (2010)

Italy

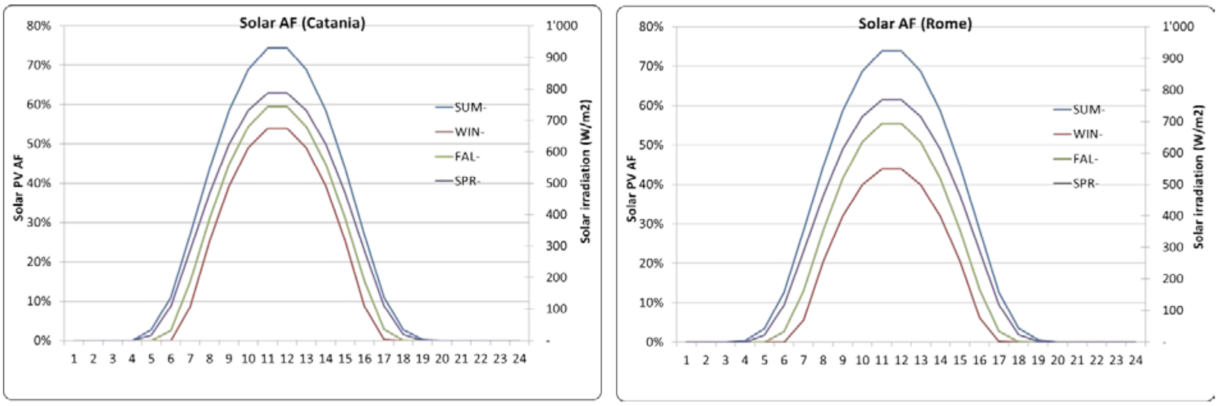
Existing technology

Table A 4: Italy - Existing Technology & model calibration (2010)

Technology Description	Stock capacity (GW)	Production (PJ)	Eff (%)	AF (%)	Peak contribution
Hydro (River)	9.8	136	80%	45%	90%
Hydro (Dam)	4.4	48	80%	35%	90%
Pump hydro	7.7	12	74%	12%	100%
Solar: PV	3.5	7	100%	19%	0%
Wind: Onshore	5.8	33	100%	25%	0%
Geothermal	0.8	19	100%	90%	50%
Biogas	1.1	19	41%	53%	30%
Wood/Biomass	1.2	16	15%	46%	90%
Coal: SCPC	11.2	143	38%	54%	90%
Gas: GTCC Base load	22.5	333	51%	74%	100%
Gas: GTCC flexible load	14.9	220	42%	59%	100%
Oil Engine	23.1	124	35%	64%	100%

Source: TERNA 2010; ENTSO-E; OECD iLibrary.

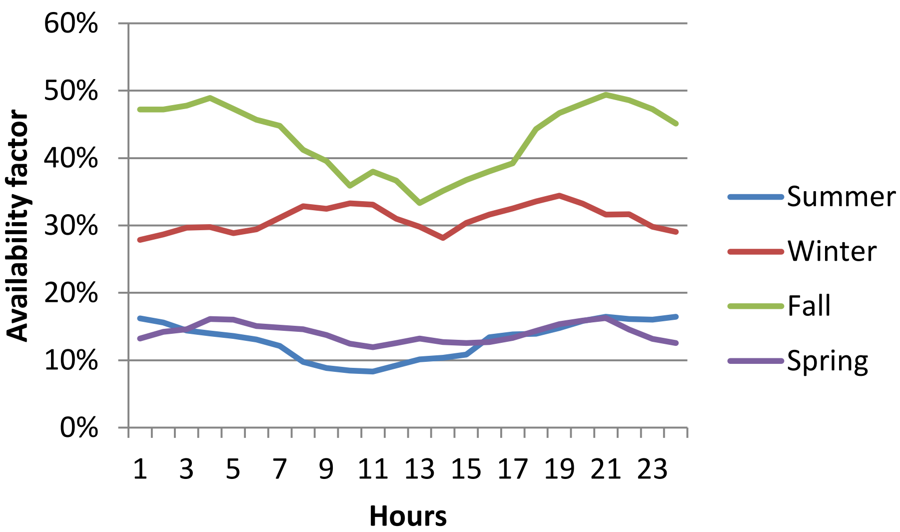
Solar availability factors



Source: JRC, 2013.

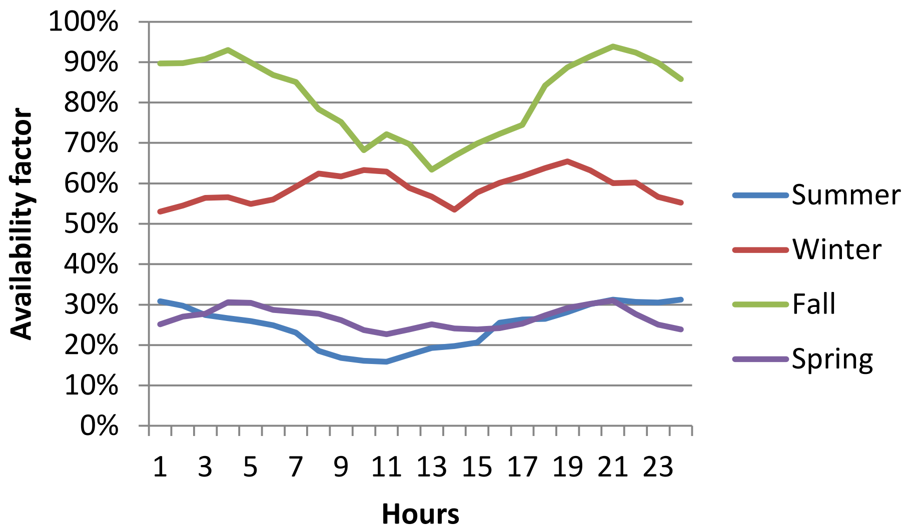
Figure A 12: Italy - Solar availability factors (Catania & Rome)

Wind availability factors



Source: TERNA 2010.

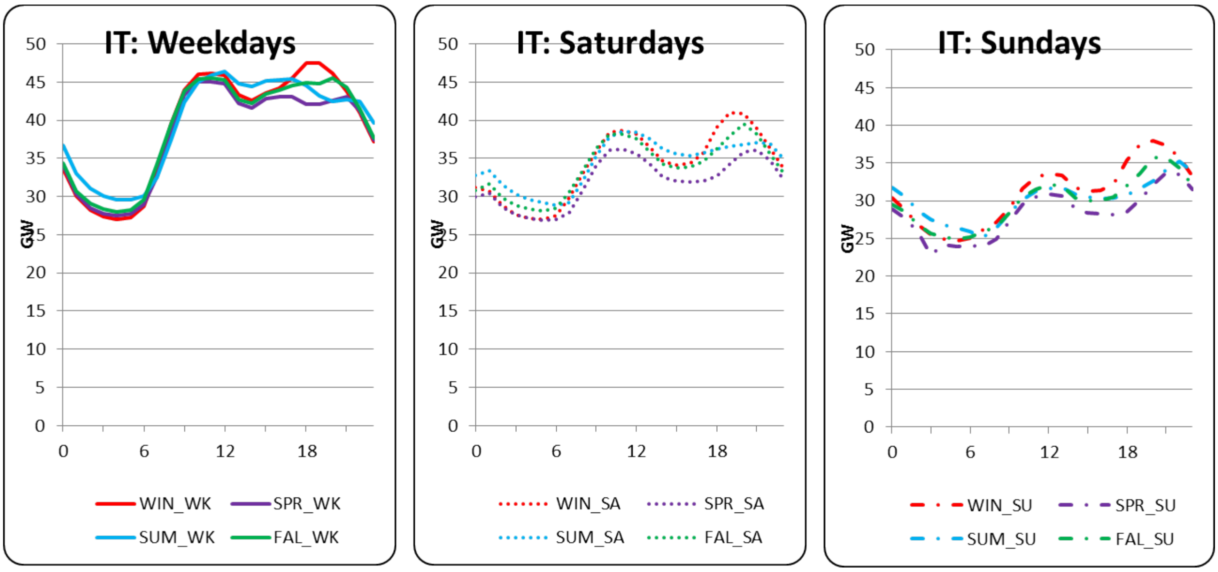
Figure A 13: Italy - Wind availability factor (onshore)



Source: TERNA 2010.

Figure A 14: Italy - Wind availability factor (offshore)

Electricity demand profiles



Source: ENTSO-E.

Figure A 15: Italy - Electricity load profiles (2010)

Switzerland

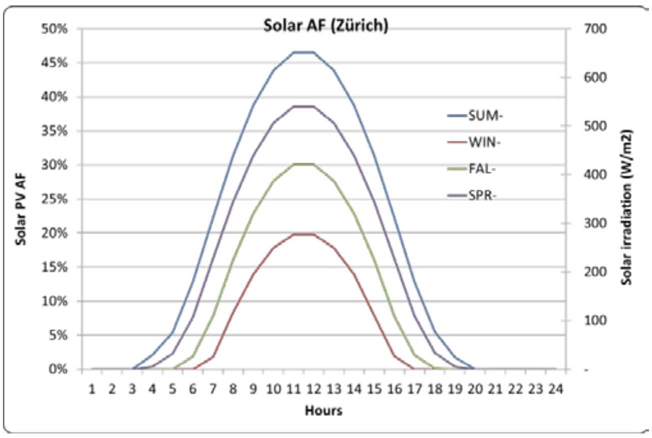
Existing technologies

Table A 5: Switzerland - Existing Technology & model calibration (2010)

Technology Description	Stock capacity (GW)	Production (PJ)	Eff (%)	AF (%)	Peak contribution
Hydro (River)	3.7	58	80%	55%	90%
Hydro (Dam)	8.1	70	80%	28%	90%
Pump hydro	1.4	7	80%	19%	100%
Solar: PV	0.1	0.3	100%	11%	0%
Wind: Onshore	0.04	0.13	100%	14%	0%
Biogas	0.3	0.01	32%	57%	30%
Wood/Biomass	0.03	0.5	13%	38%	90%
Waste Incinerator	0.3	5.5	40%	57%	30%
Gas: GTCC Base load	0.6	7.2	35%	57%	100%
Nuclear (Mühleberg)	0.365	9.5	30%	96%	90%
Nuclear (Beznau - 1)	0.365	10.2	30%	96%	90%
Nuclear (Beznau - 2)	0.373	10.7	30%	91%	90%
Nuclear (Gösgen)	0.970	28.7	30%	94%	90%
Nuclear (Leibstadt)	1.2	31.6	30%	90%	90%
Oil Engine	0.1	0.06	18%	38%	100%

Source: BfE 2010; ENTSO-E; OECD iLibrary; Kannan/Turton 2011.

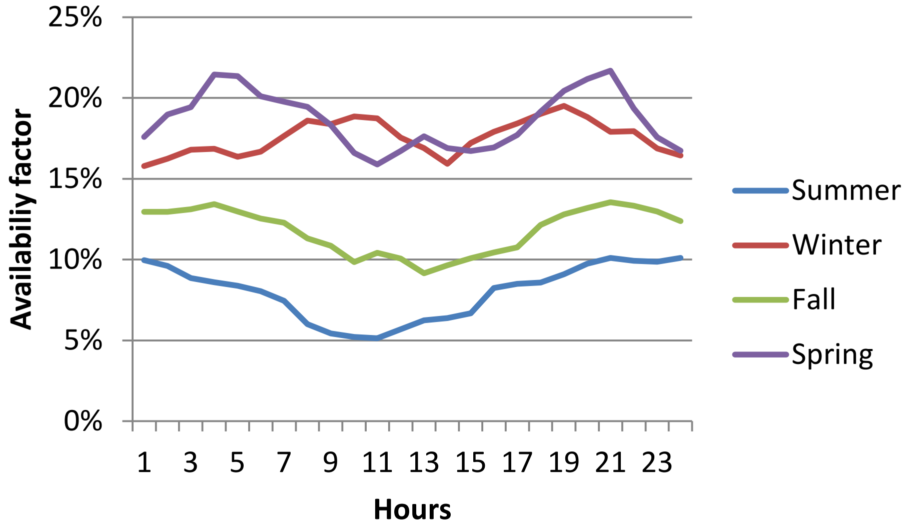
Solar availability factors



Source: JRC 2013.

Figure A 16: Switzerland - Solar availability factors (Zürich)

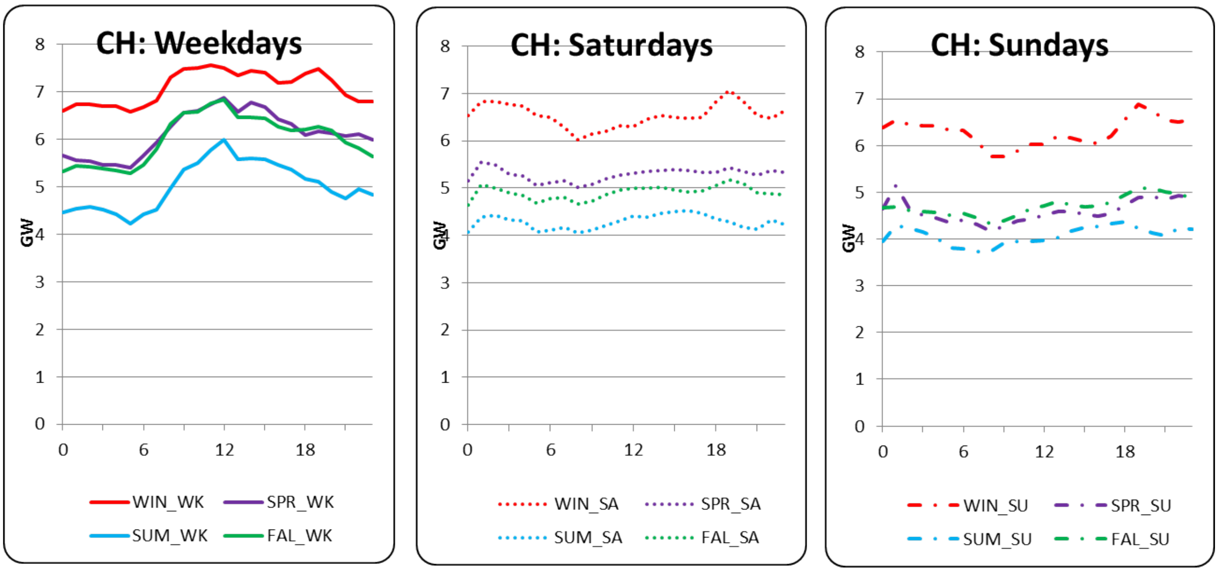
Wind availability factors



Source: Kannan/Turton 2011.

Figure A 17: Switzerland - Wind availability factor (onshore)

Electricity load profiles



Source: ENTSO-E.

Figure A 18: Switzerland - Electricity load profiles (2010)

Appendix B – Supplementary results for Chapter 4

Country specific results – generation mix

France

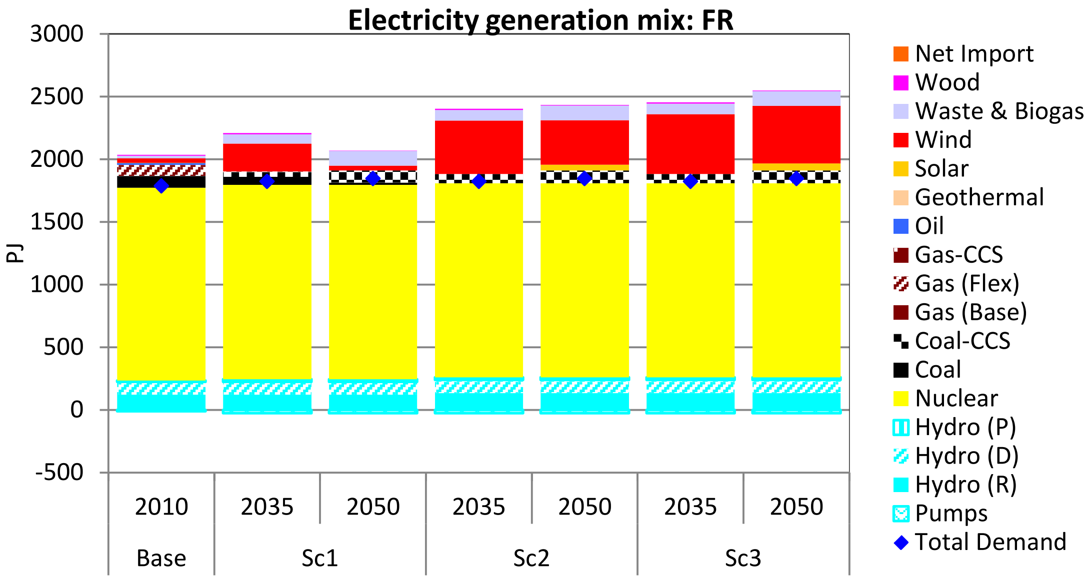


Figure B 1: France - electricity generation mix

Germany

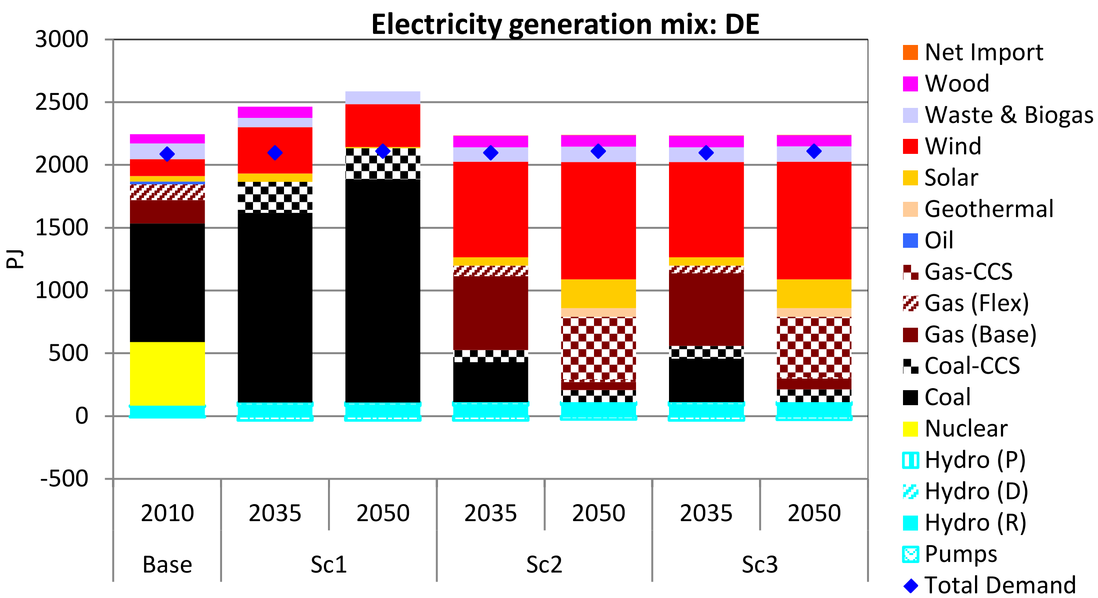


Figure B 2: Germany - electricity generation mix

Italy

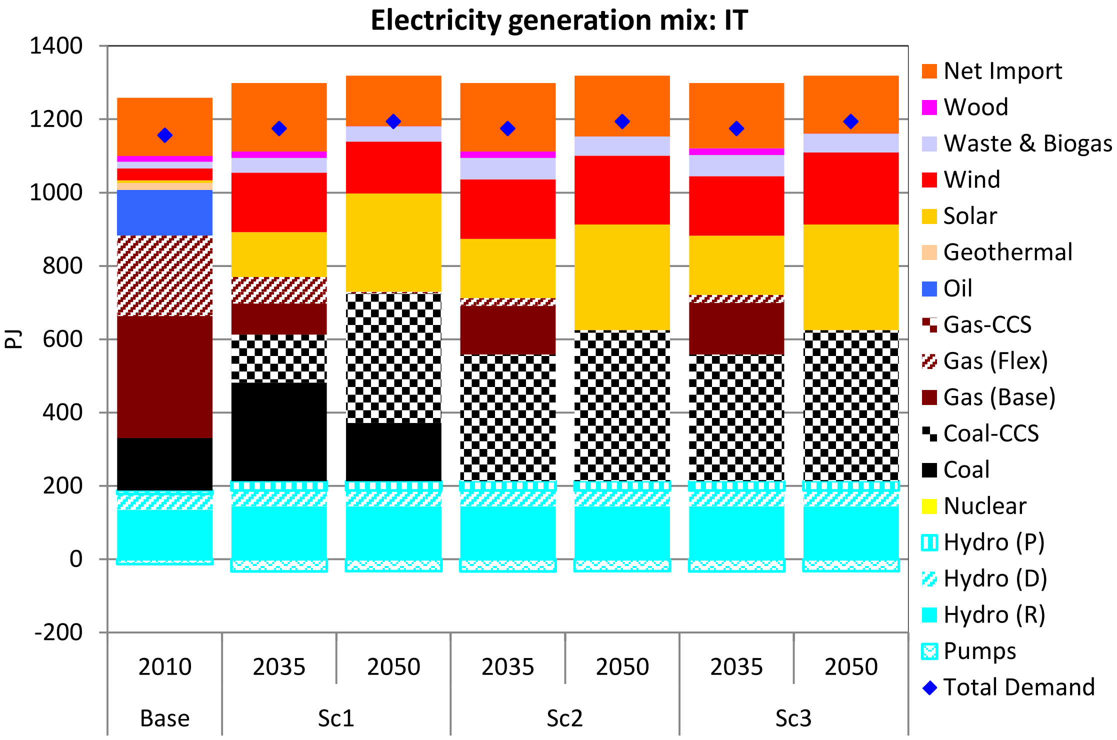


Figure B 3: Italy - electricity generation mix

Austria

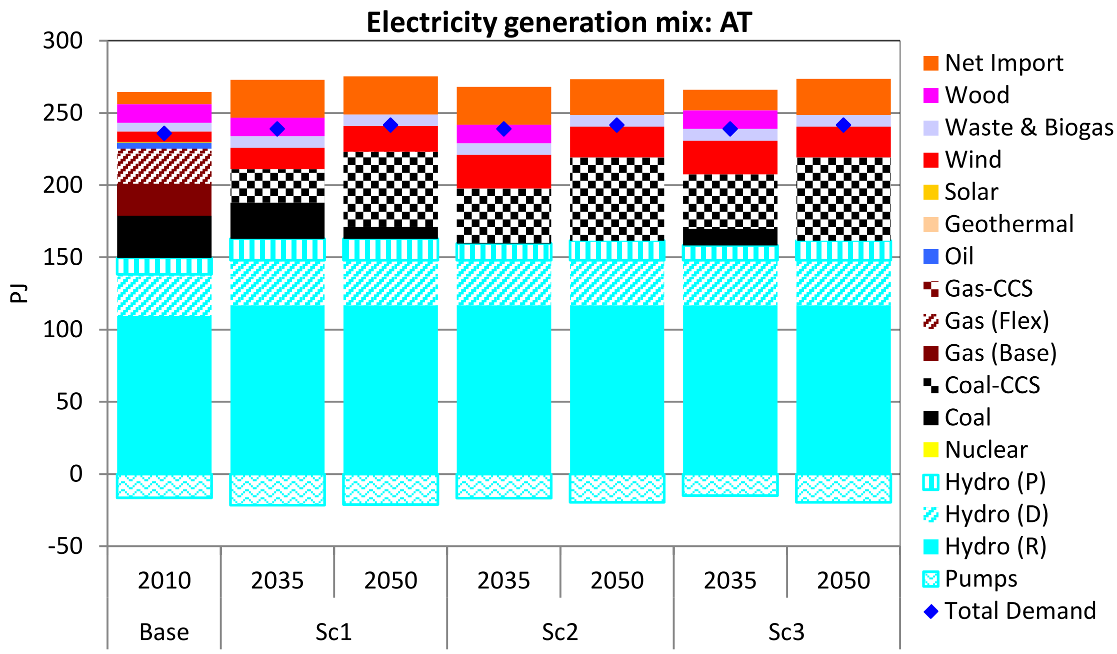


Figure B 4: Austria - electricity generation mix

Generation schedule results in CROSSTEM – *Sc1* scenario

Scenario 1(Sc1) – summer weekday 2050

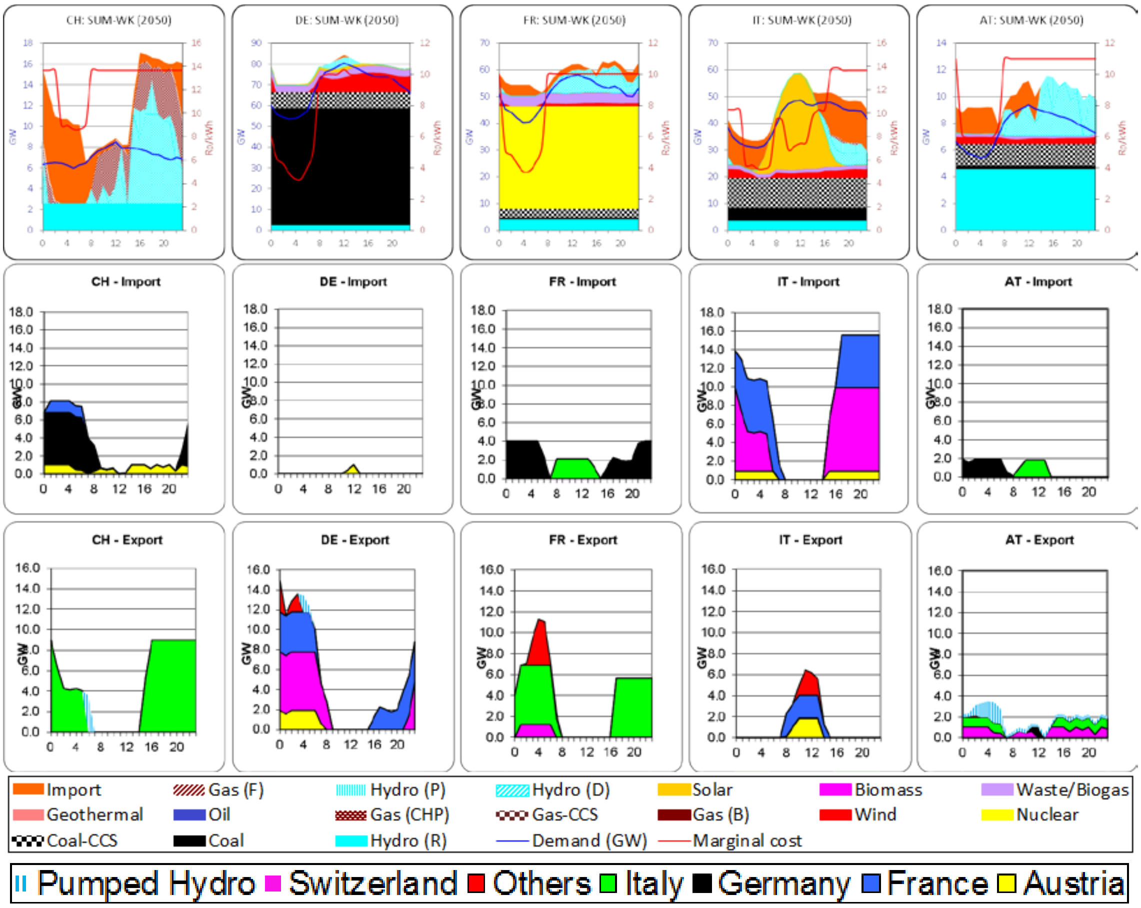


Figure B 5: Electricity generation schedule for all countries on a summer weekday 2050 (Sc1)

Scenario 1(Sc1) – winter weekday 2050

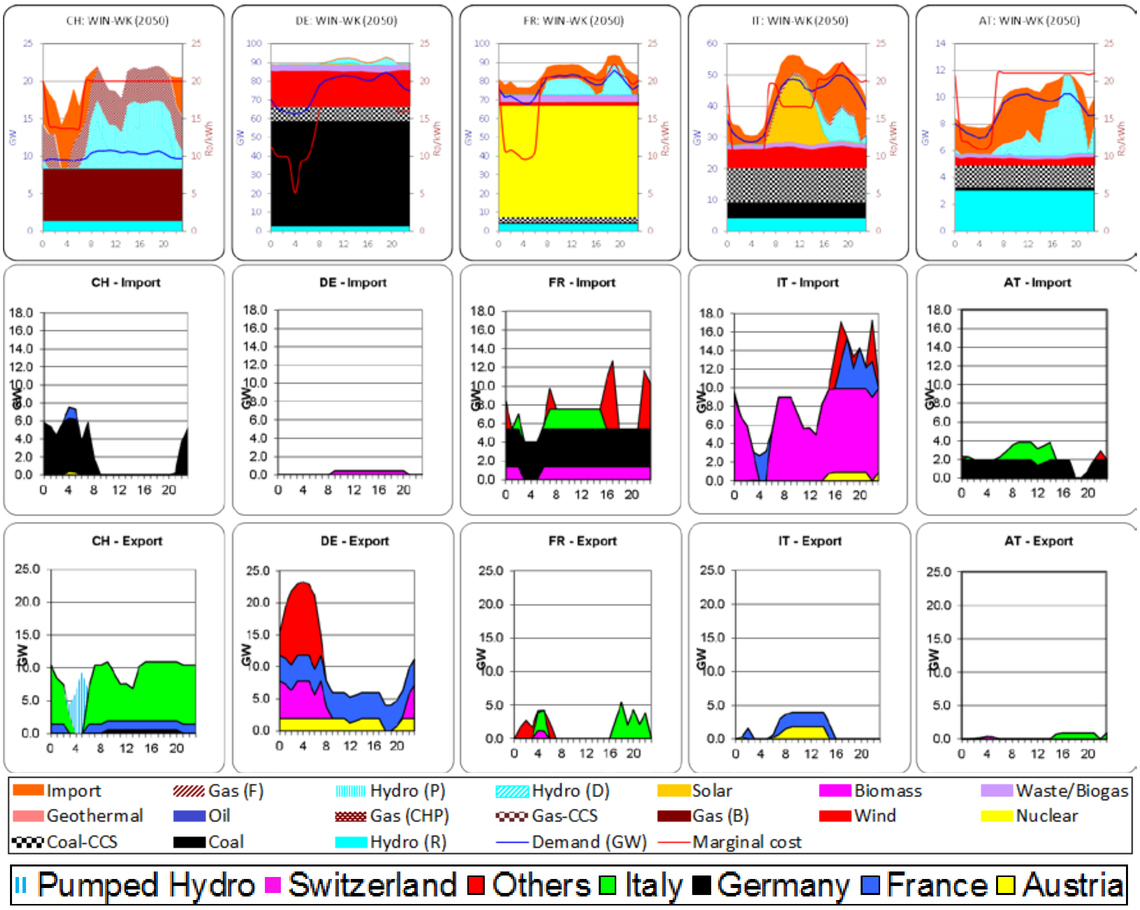


Figure B 6: Electricity generation schedules for all countries on a winter weekday 2050 (Sc1)

Electricity net import restrictions for Switzerland in *Sc3* (CROSSTEM) and *NoGas* (CROSSTEM-CH) scenarios

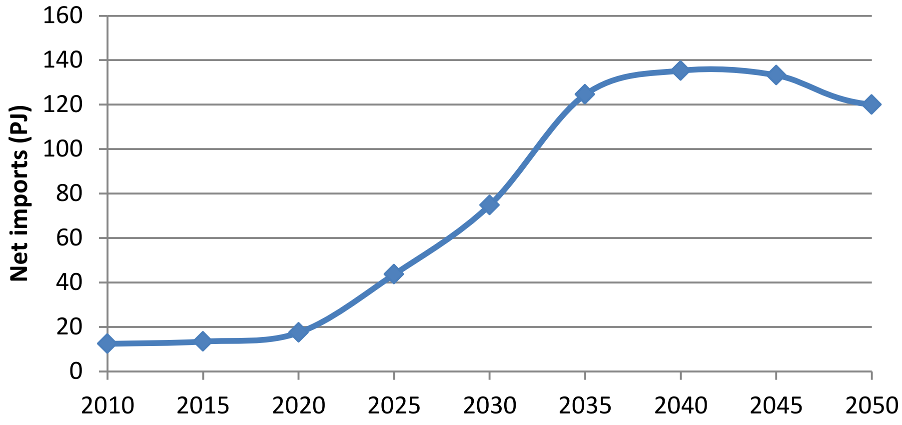


Figure B 7: Net electricity import allowance for Switzerland in *Sc3* and *NoGas* scenarios

APPENDIX C – SUPPLEMENTARY RESULTS FOR CHAPTER 5

Interconnector capacities – 2010 vs 2050

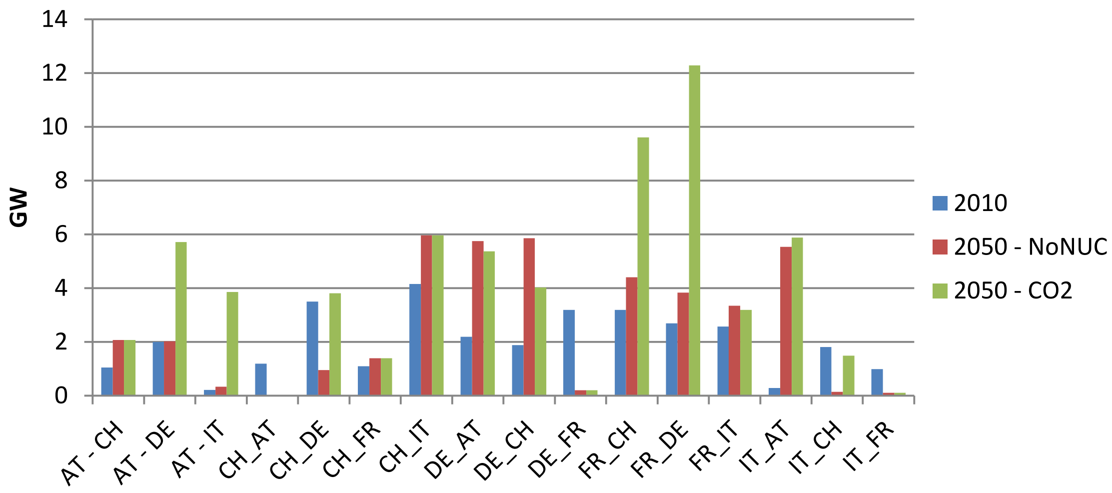


Figure C 1: Interconnector capacity expansion in CROSSTEM

Sensitivity Analysis – High technology costs

CO2-HighTechCost – Cost of nuclear and CCS technologies doubled, cost of solar PV and wind halved. Remaining boundary conditions same as *CO2*

Switzerland generation mix

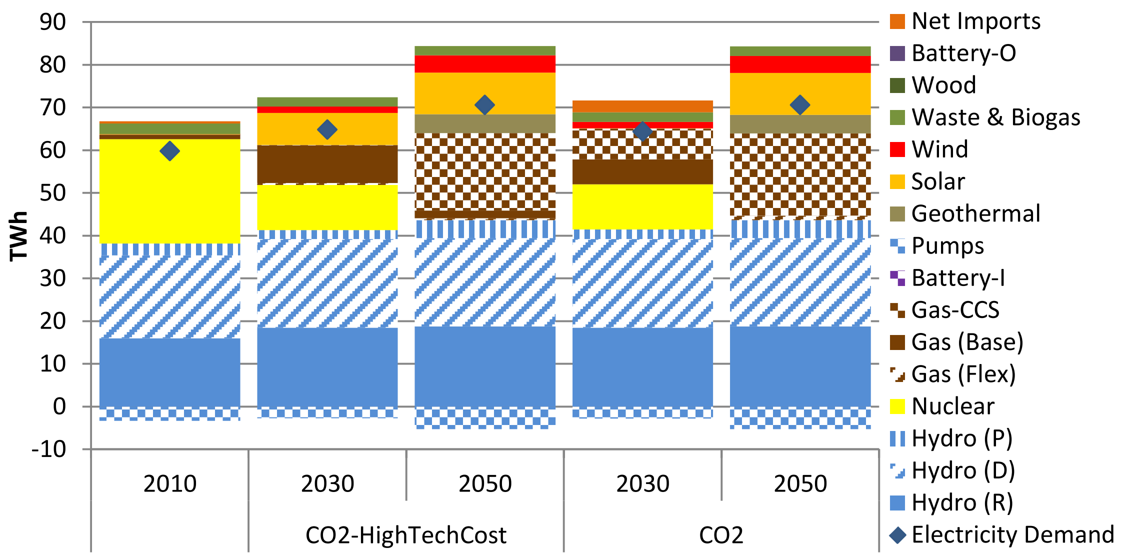


Figure C 2: Switzerland generation mix

Switzerland installed capacity

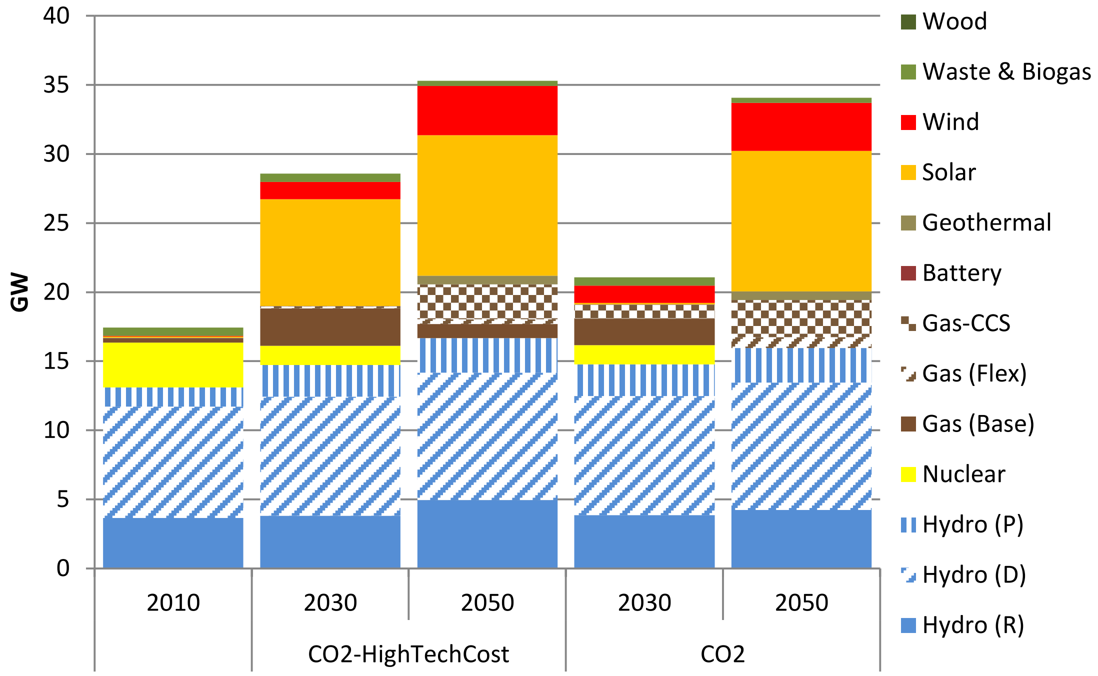


Figure C 3: Switzerland installed capacity

CROSSTEM generation mix

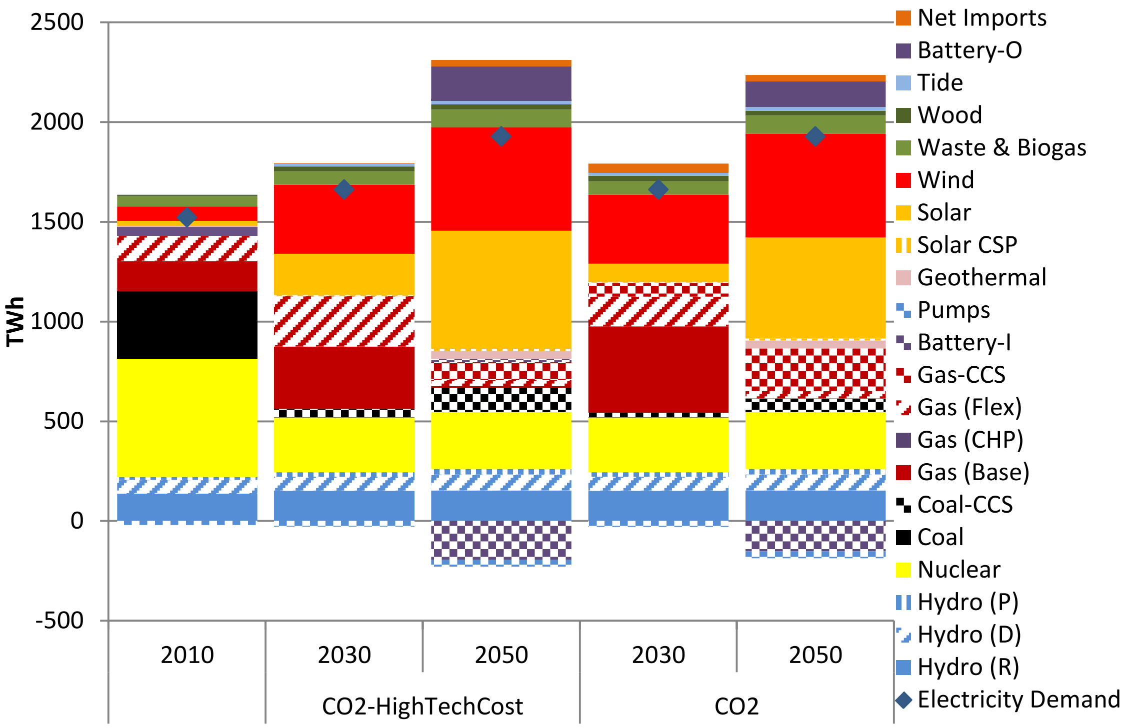
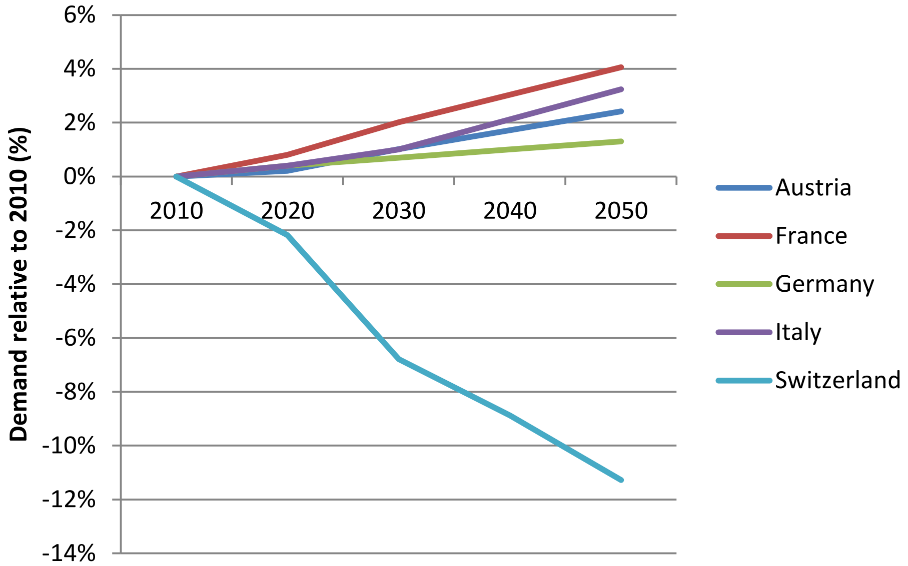


Figure C 4: Generation mix of all countries

Sensitivity Analysis – Low electricity demand assumption



Source: ELECTRA project report, PROGNOS AG, 2012

Figure C 5: Low electricity demand assumption

APPENDIX D – SUPPLEMENTARY RESULTS FOR CHAPTER 7

Italy

Generation profile in summer 2050

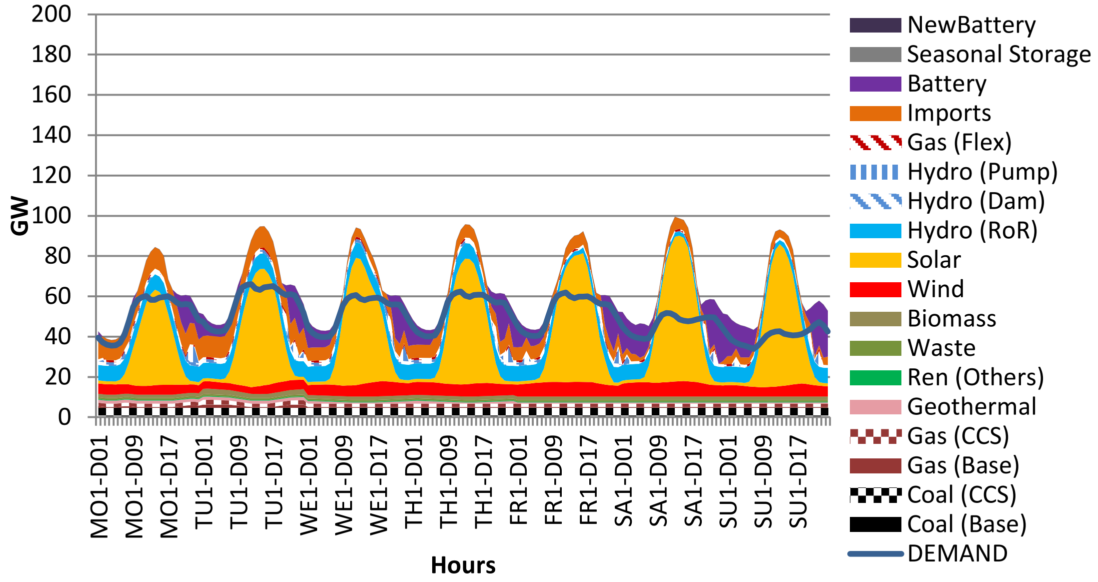


Figure D 1: Italy generation profile – summer 2050

Generation profile in winter 2050

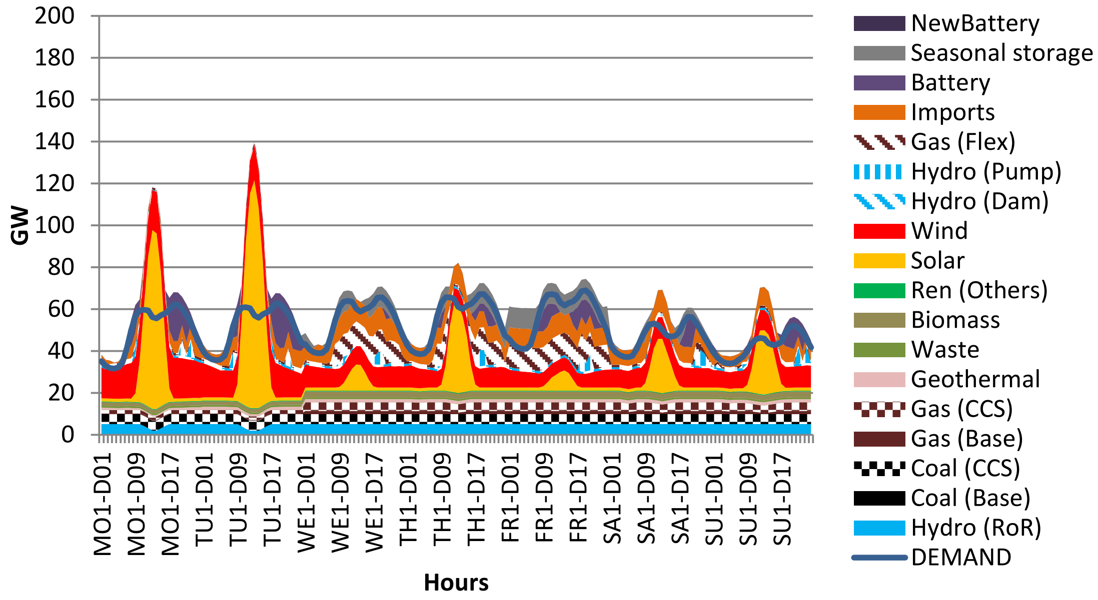


Figure D 2: Italy generation profile winter 2050

Germany

Generation profile – summer 2050

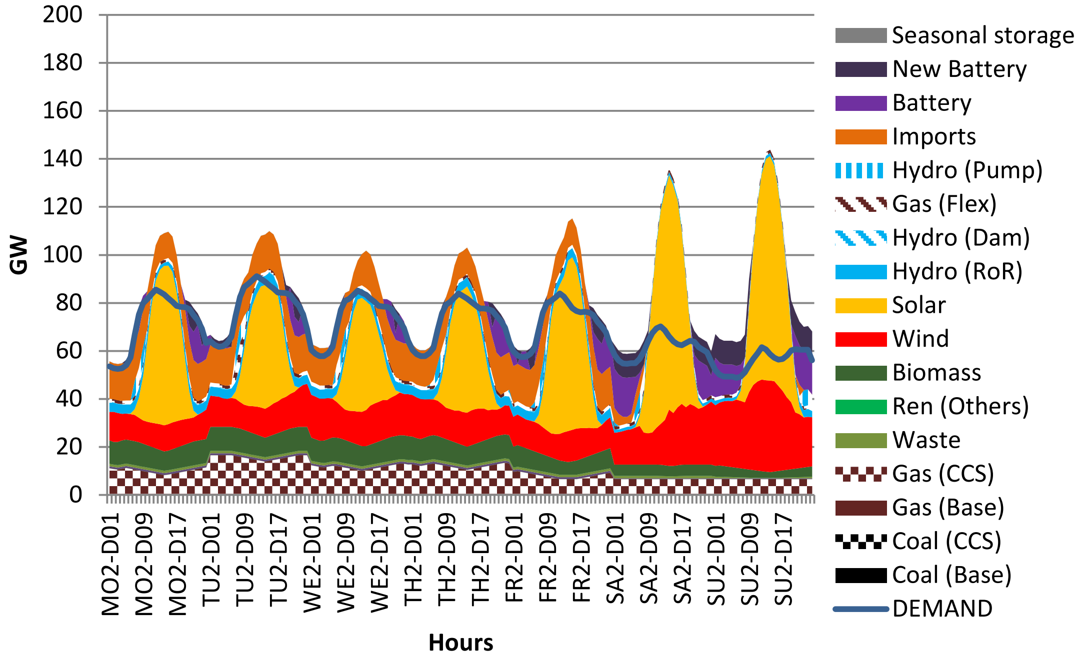


Figure D 3: Germany generation profile - summer 2050

Generation profile – winter 2050

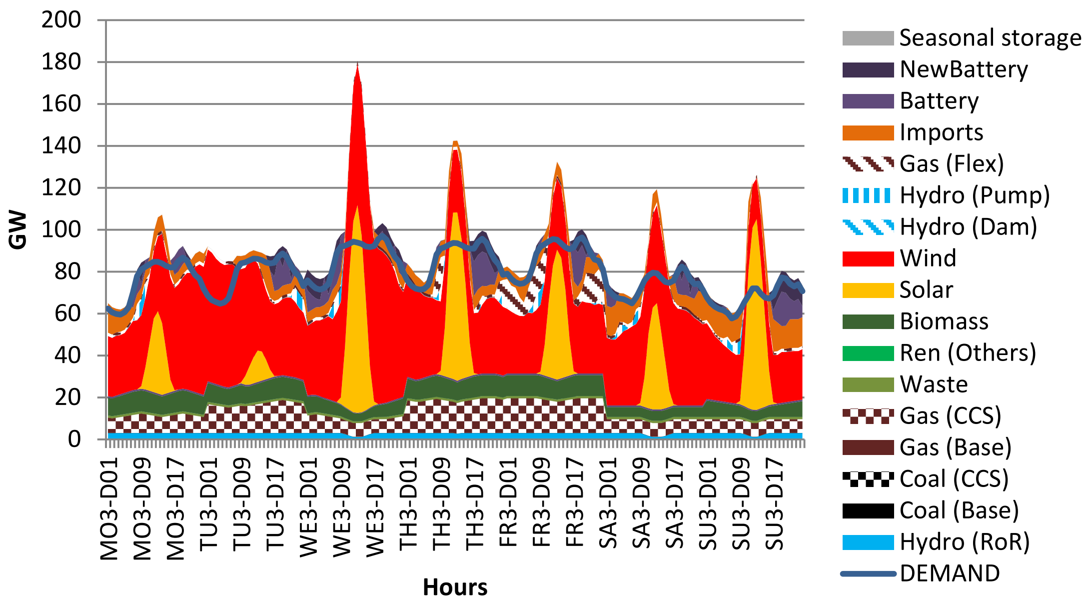


Figure D 4: Germany generation profile - winter 2050