Scenario modelling and optimisation of renewable energy integration for the energy transition

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To my grandma, a life devoted to others.

“Impossibility is a kiss away from reality.”
Amanita

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Abstract

A large number of countries have engaged themselves in an energy transition towards more renewable energy in their energy systems. Motivations stem mainly from the need to reduce CO_2 emissions, and from a desire of their population to phase out technologies such as nuclear. Most of these countries promote biomass, wind and solar energy sources, among other possibilities. However the current rate of deployment of renewable energy systems globally is not sufficient to reach the CO_2 emissions reduction that would allow to maintain the global average temperature increase below the 2°C threshold. The main barriers to a wider integration of renewable energy systems are *i*) their limited realisable potential, *ii*) their still limited competitiveness, *iii*) their intermittence; *iv*) public acceptance often related to poor level of energy literacy amongst citizens. Citizens are key decision-makers. They must decide on energy policies and on the energy technologies they use, hence they have the power to foster or halt the energy transition.

This thesis presents two different strategies for addressing the problem of the integration of renewable energy sources for energy transitions. The first one (*Chapter 1*) consists in developing an energy modelling tool to help decision-makers understand the energy system and find their own answers. The modelling approach also includes a new methodology for the calculation of the total cost of a national energy system. A model of the Swiss energy system has been created following this approach, which serves as basis to develop the Swiss-Energyscope online calculator. This calculator and its model present an optimal trade-off between scientific rigour and user-friendliness, which allows the reproduction of the energy transition scenarios conceived by the Swiss Government, and consequently its use for energy policy making.

The second strategy (*chapters 2 and 3*) profits from the possibilities offered by mathematical modelling and optimisation to analyse national energy systems, and derive insights for policy and decision-makers. First, a methodology using a mix-integer linear programming (MILP) model analyses biomass usage pathways to determine its optimal use in Switzerland in 2035. Second, in order to study the role of biomass, non-linear optimisation is applied to create future scenarios. (*Chapter 3*) focuses on the solutions to deal with the variability of renewable electricity. To this end, a MILP model with hourly time resolution is conceived to study the use of flexible electricity supply and demand options for the integration of renewable electricity.

The optimisation methodologies are validated on case studies for the Swiss energy system. Regarding biomass, the results reveal that woody biomass chemical conversion technologies can allow for an overall better performance in terms of CO_2 avoided emissions compared to direct combustion, as long as the produced biofuels are used in efficient technologies. Results also show that the combination of the gasification-methanation process of woody biomass with the production of H_2 produced from excess electricity would allow to reduce the Swiss natural gas imports to zero by 2050. Concerning the integration of variable renewable electricity, the cost difference between using flexible electricity supply- and demand-options or electricity imports to deal with variable renewable electricity is below 2.5% of the total cost of the energy system.

Keywords
Renewable energy; renewable electricity; energy transition; energy scenarios; energy planning; energy policy; national energy systems; energy modeling; decision-making support; energy calculator; energy literacy; optimization; mixed-integer linear programming; Switzerland; woody biomass conversion; biomass conversion pathways; biofuels; exergy.

Résumé

Un grand nombre de pays se sont engagés dans une transition énergétique visant à une augmentation des renouvelables dans leur système énergétique. Leurs motivations découlent principalement du besoin de réduire les émissions de CO_2 ainsi que du désir des populations de s'affranchir de technologies telles que le nucléaire. La plupart de ces pays encouragent des solutions de type renouvelable, parmi lesquelles la biomasse, l'éolien et le solaire. Cependant, le taux de déploiement actuel de ces solutions n'est globalement pas suffisant pour atteindre les objectifs de réduction des émissions de CO_2 permettant de limiter l'augmentation de la température mondiale en dessous du seuil des 2°C. Les principales barrières à une meilleure intégration des énergies renouvelables aux systèmes énergétiques sont : *i*) leur potentiel limité, *ii*) leur faible compétitivité, *iii*) leur intermittence, *iv*) la méfiance du grand public souvent liée à un faible niveau de connaissances en énergie. Les citoyens doivent décider des politiques énergétiques et des technologies utilisées, et se retrouvent donc en tant qu'acteur principaux, avec le pouvoir de favoriser ou d'empêcher la transition énergétique.

Cette thèse propose deux approches différentes afin de répondre au problème de l'intégration des énergies renouvelables dans le cadre de la transition énergétique. La première (*Chapitre 1*) consiste à développer un outil de modélisation énergétique destiné à aider les responsables politiques à comprendre le système énergétique pour en tirer leurs propres conclusions. Cette approche de modélisation inclut une nouvelle méthodologie de calcul du coût total du système énergétique à l'échelle nationale. Un modèle du système énergétique suisse a été créé à partir de cette approche, puis utilisé comme structure de base pour le calculateur en ligne Swiss-Energyscope. Ce calculateur présente ainsi un bon compromis entre rigueur scientifique et facilité d'utilisation, ce qui permet de reproduire les scénarios énergétiques conçus par la Confédération Suisse et d'utiliser les résultats du calculateur pour définir la nouvelle stratégie énergétique.

La seconde approche (*chapitres 2 et 3*) se base sur un modèle mathématique et son optimisation pour analyser le système énergétique suisse afin d'en tirer des perspectives pour la stratégie et les responsables politiques. Un modèle de programmation linéaire mixte en nombre entiers (MILP) a initialement été utilisé afin d'analyser les filières de valorisation de la biomasse et ainsi déterminer son utilisation optimale selon les scénarios envisagés à l'horizon 2035. Une optimisation non linéaire a ensuite été utilisée pour générer des scénarios futurs. Le (*chapitre 3*) se concentre sur les alternatives pour pallier à la variabilité de la production d'électricité renouvelable. Un modèle MILP avec une résolution horaire a été créé pour étudier la flexibilité de la production d'électricité et les possibilités d'adaptation de la demande afin d'améliorer l'intégration des énergie renouvelables. Dans le cadre du système énergétique suisse, les méthodes d'optimisation sont validées par des études de cas. En ce qui concerne la biomasse, les résultats révèlent que les technologies de conversion chimique de la biomasse ligneuse permettent une meilleure réduction globale des émissions de CO_2 par rapport à la combustion directe, à condition que les biocombustibles soient utilisés par des technologies efficaces. Les résultats montrent aussi que la combinaison du processus de gazéification-méthanisation de la biomasse ligneuse couplé à la production de H_2 à partir d'électricité excédentaire permettrait de réduire les importations suisses de gaz naturel à zéro d'ici 2050. Quant à la différence de coût entre un système flexible de production et demande d'électricité ou une importation afin de pallier à la nature variable de l'électricité d'origine renouvelable ne correspond qu'à 2.5% du coût total du système énergétique.

Mots-clefs
énergie renouvelable ; électricité renouvelable ; transition énergétique ; scénarios énergétiques ; planification énergétique ; politique énergétique ; systèmes énergétiques nationaux ; modélisation énergétique ; aide à la décision ; calculateur énergétique ; connaissances en énergie ; optimisation ; programmation linéaire en nombre entiers ; Suisse ; conversion de la biomasse ligneuse ; voies de conversion de la biomasse ; biocarburants ; exergie.

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Acronyms and abbreviations

Adv	Advanced
BAU	Business as usual
BEV	Battery electric vehicle
BIGCC	Biomass integrated gasification combined cycle
Bio2CH4	Gasificaiton & methanation
Bio2CH4el	Gasificaiton & methanation with electrolyser
BtL	Biomass To Liquids
BWC	Building type / weather stations / construction period
CAES	Compressed air energy storage
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CNG	Compressed natural gas
Dec	Decentralised
DEH	Direct electric heating
DHN	District heating network
DR	Demand response
DRY	Design reference year
DSM	Demand side management
EM	Electricity market
EV	Electric vehicle
FC	Fuel cell
FT	Fischer-Tropsch
FTel	Fischer-Tropsch with electrolyser
Gas-FC-GT	Integrated gasifier with fuel cell and gas turbine
GHG	Greenhouse gas
GM	Generation multiple
GT	Gas turbine
GWP	Global warming potential

HEV	Hybrid electric vehicle
HHV	Higher heating value
HP	Heat pump
HTG	Hydrothermal gasification
HW	Hot water
Ind	Industry
INDC	Intended nationally determined contribution
IPCC	Intergovernmental panel on climate change
KPI	Key performance indicator
LCA	Life cycle assessment
LCOE	Levelised cost of electricity
LHV	Lower heating value
LNG	Liquified natural gas
MGT	Externally-fired gas turbine
MILP	Mixed-integer linear programming
MOO	Multi-objective optimisation
MPC	Model predictive control
NEP	New Energy Policies
NES	National energy systems
NG	Natural gas
O&M	Operation and maintenance
OPEX	Operating expenses
P2G	Power-to-gas
P2H	Power-to-heat
P2L	Power-to-liquid
PHEV	Plug-in hybrid electric vehicle
PHS	Pumped hydro storage
pkm	Passenger-kilometer
PS	Power sector
PV	Photovoltaic
Pyro	Fast pyrolysis
PyroUp	Fast pyrolysis with upgrading
SFOE	Swiss Federal Office of Energy
SH	Space heating
SI	Supplementary information
SNG	Synthetic natural gas
SOFC	Solid oxide fuel cell
SOFC-GT	Hybrid cycle solid oxide fuel cell and gas turbine

ThHP	Thermal heat pump
tkm	Ton-kilometer
V2G	Vehicle-to-grid

Introduction

Extending current trends to the year 2050, the International Energy Agency (IEA) projects a 70% increase in global energy demand and a 60% increase in greenhouse gas emissions (GHG) compared with 2011 [17]. This potentially would imply devastating consequences related to climate change. In order to constrain the expected increase in global temperatures to a 2°C, the Intergovernmental Panel on Climate Change (IPCC) urges to cut fossil CO_2 emissions by 65% in 2050, in comparison to 2011 levels [18]. Thus, most countries have engaged in energy transitions towards more renewable energy in their energy systems.

In addition concerns with regards to the negative impact on health and environment of certain technologies fosters the energy transition. After Fukushima accident some countries like Germany [19] or Switzerland [20] decided to gradually phase out nuclear. Germany has also plans to lower their dependency from coal electricity [21], not only because of the GHG emissions, but also because of the release to the atmosphere of harmful pollutants such as NO_x, SO_2 [22] and heavy metals by plants even equipped with electrostatic filter and a flue gas desulfurization [23]. At city levels, the attention is drawn towards conventional internal combustion vehicles. Some cities, such as Copenhagen and Paris, plan to van access to diesel vehicles in the future [24], since the particles emitted by this type of vehicles are classified as carcinogenic agents [25].

Despite the stated determination of countries through their intended nationally determined contributions (INDCs), the deployment ratio of renewable energy sources has still not reach the required level to limit the effects of global warming. Moreover, the announced INDCs will only reach the 3.7°C threshold, even if all declared contributions are met [26]. Figure 1 compares the estimated pasted annual global CO_2 emissions to the emissions pathways developed by the IPCC. The current emissions trend is closer to the pathway leading to an increase of 5°C by 2100 rather than the one limiting it to 2°C. Hence it is necessary to identify the reason undermining the deployment of renewable energy systems.

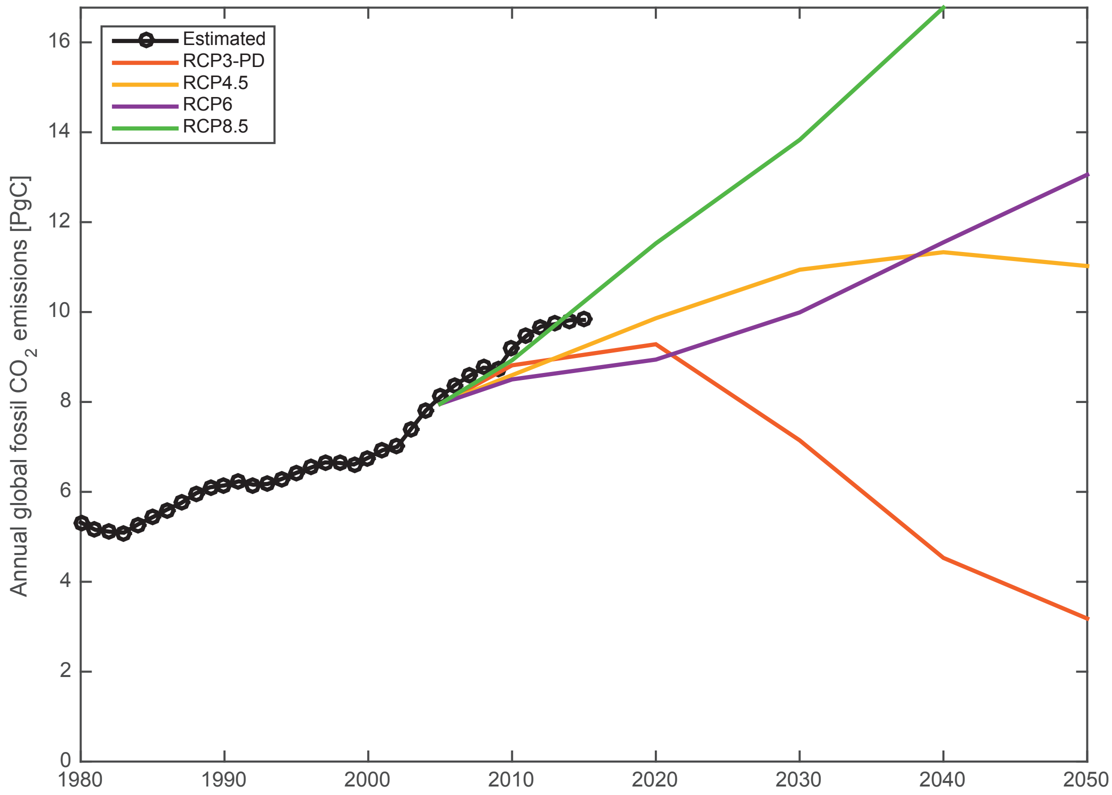

Figure 1 – Estimated annual global fossil CO_2 emissions compared to the Representative Concentration Pathways (RCPs) from IPCC. RCP3-PD conveys to a mean global temperature increase of 1.5°C (range of 1.3-1.9°C) by 2100, RCP4.5 to 2.4°C (range of 1.0-3.0°C), RCP6 to 3.0°C (range of 2.6-3.7°C) and RCP8.5 to 5.0°C (range of 3.5-6.2°C) [27] [18].

Constraints and solutions for the integration of renewable energy systems

Limited realisable potential

From a technical point of view renewable energies offer enough potential to have a 100% renewable energy system at global level. In only 90 minutes, the solar radiation reaching the earth is equivalent to the annual worldwide energy consumption [28]. Nevertheless this potential is non-uniformly distributed across the earth. The energy consumption is also not evenly distributed, about 75% of the global energy consumption is located above the Cancer tropic [29]. Hence this pose a problem of matching potentials with demands.

In addition, potentials vary strongly between neighbouring countries. For example, onshore wind power in Germany has an annual electricity production potential of about 8000 MWh/km^2 [30], while in Switzerland is 100 MWh/km^2 [31]. This big difference is explained by the Swiss orography, but also by the fact that Switzerland is a small country densely populated. For the calculation of the potential projected wind parks should not be too close to residential buildings and their landscape impact should be considered acceptable. These two constraints have an important effect on the potential. At continental and national level, the reinforcement of the high voltage electricity transmissions grids is meant to bring the renewable electricity to the consumers, but the construction of high voltage lines also has public acceptance problems.

Biomass is the only renewable energy source that can be transported as primary energy where it is needed, without any efficiency penalty. In 2014, biomass was the first renewable energy source covering 10.3% of the global primary energy supply [32]. Biomass chemical conversion processes allow the production of solid, liquid and gaseous biofuels, which can substitute almost any kind of fossil fuel and the associated greenhouse gas emissions. Nevertheless biomass is a scarce, diffused, low density resource and its use for energy can enter in competition with land use for food and fodder. Therefore it is necessary to make the best use of available biomass in order to maximize its CO_2 emissions abatement potential.

In conclusion, renewable energy sources have a limited realisable potential which is not uniformly distributed across the globe. Nevertheless, studies have demonstrated that it is possible to have a global energy system free of fossil fuels if those potentials are efficiently exploited [33].

Competitiveness

Energy system have a big time inertia. Strategic energy plans have a 20 to 50 years time horizon due to the life time of the technologies being installed [34]. Hence it takes decades to appreciate the effects of technological advances on the installed capacity mix. The vast majority of the existing production capacities where installed at least 20 years ago. 20 years ago the costs of new renewable technologies like PV or wind were far from competing with conventional technologies such as coal power plants. By 1995 in the US the levelised cost of electricity (LCOE) for PV was about 5 times the cost of coal electricity [35]. In the same country, 15 year later, the difference was reduced by almost half [36]. And the cost reduction trend has accelerated in the last decade.

Figure 2 shows the investment cost evolution of onshore wind parks, PV modules (thin film type), and batteries for EVs. The cost of the last two technologies has been reduced by more than 70% in a 7 years period time. In the case of the on shore wind park a 30% reduction is appreciated. These price evolutions have a direct impact on the contracts signed by the PV and wind plants developers. In Chile and the United Arab Emirates, the agreed prices are below 30 USD/MWh$_e$ for PV plants. For wind electricity, contracts where signed in Netherlands at 55 USD/MWh$_e$ [2]. These prices contrasts with the agreement for the future nuclear plant in Hinkley (UK) which warranties a 126 USD/MWh$_e$ for the delivered electricity [37]. Nevertheless, the investments costs and LCOEs does not reflect the extra cost related to the need for flexibility and/or storage options to cope with the variability of electricity supply from PV and wind. This aspect is treated in detail in the following section.

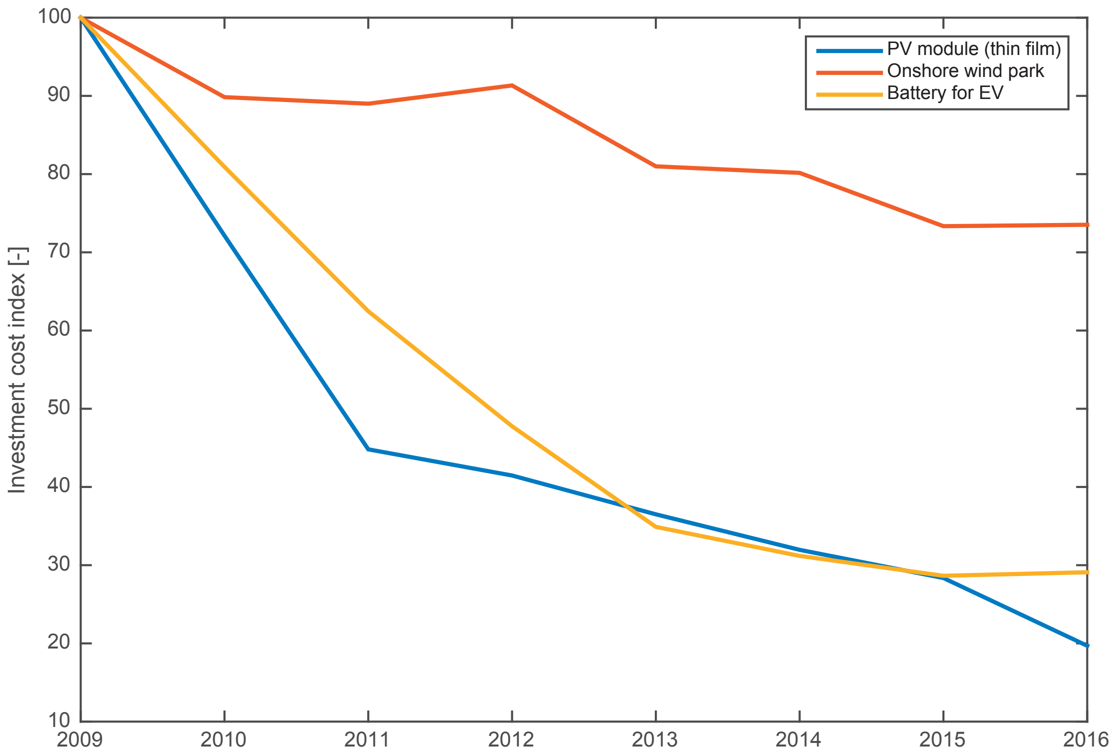

Figure 2 – Investment cost evolution of PV modules (thin film) [1], onshore wind parks [2] and batteries for EVs [3].

The capital expenditure (CAPEX) component in the total cost of a technology tends to be more relevant for renewable energy and efficient technologies than for conventional technologies using fossil fuels. Obviously this increase is compensate by a reduction on the operating expenses (OPEX). The higher CAPEX hampers the deployment of certain technologies such as heat pumps (HPs), battery electric vehicles (BEVs) and PV. A case study for Switzerland comparing a conventional gasoline car and an equivalent BEV shows that even if the investment of the BEV is 80% higher in comparison to the gasoline car, its total ownership cost (fuel, purchase, maintenance and taxs cost) is 10% lower [38]. The same conclusion applies when comparing air-water HPs to light fuel oil boilers. In Switzerland the installation cost of a HP can be up to 180% more expensive than that of a light fuel oil boiler. However, the boiler can be up to 69% more expensive when considering the total ownership cost [39]. The compensation between the higher CAPEX and the lower OPEX might not be obvious to the average citizen, who ultimately takes the purchase decision. The higher CAPEX can however represent an intrinsic barrier to deployment, as it requires access to capital

Intermittence of the new renewable electricity

Intermittent renewables, specially wind and solar PV, present a variability and uncertainty component that increases the complexity of the electricity supply-demand balance. Their electricity supply patterns have a seasonal, daily and sub-minutes component, the last one specially marked in the case of PV electricity. These are characteristics were not present in conventional electricity sources, hence it is necessary to find strategies and measures to deal with them. This section attempts to provide an analysis for technologies and strategies under a multi-scale geographic scope. Nevertheless, their potential and convenience are subordinated to the national energy system specific configuration (i.e. renewables energy mix, energy efficiency levels, etc) and its geographic scope (i.e. climatic conditions). Hence this section allows to identify the most promising options to be included in future detailed studies on specific energy systems.

Combination of PV and wind

The right ratio between PV and wind installed capacity can help to decrease the daily and seasonal variability of the combined production profile of the two technologies, since their supply profiles are complementary. At daily level, PV produces during the day with its peak production at noon, while wind has the tendency to be stronger at night. In countries located above the Cancer tropic, PV capacity factor is higher during summer, while for wind the strong season is winter [40]. Nonetheless, not always is possible to meet the ratio PV/wind which minimises the variability of the combined electricity production because of their development potentials [41] or restrictions to their deployment [42]. Deploying new renewable energy systems in a large geographical area can also attenuate the variability when the whole production is considered. Solar radiation and wind might present important changes depending on the region, specially in countries with complex topography such as Switzerland [43]. This option can also be contemplated when the energy system studied is at continental level, e.g. Europe. Enhanced transmission capacities between the different countries can help to reduce investments to cope with production variability by mutualising existing infrastructure and demand [44] [45].

Excess capacity

Excess of capacity is another alternative to deal with the variability and uncertainty of PV and wind generation. But any excess capacity implies curtailment, meaning that a percentage of the generated electricity will not be consumed. That is already the case in some countries [46]. This option might not be interesting from an economic point of view, since it penalises the already low capacity factors of the two technologies. Nonetheless, the optimality of the option depends on the characteristics of the whole energy system [47].

Flexible supply

Flexible generation system can be used to balance supply and demand, when there is a decrease in renewable electricity supply. Some technologies falling in this category are hydro dams, biomass systems, new generation coal plants and gas turbine (GT). The first one is limited by its geographical availability, so only mountainous countries benefit from hydro dam potential. GT is the most widely used technology due to its low CAPEX and its quick start-up and ramping response [48]. However the operation of gas turbines introduces CO_2 emissions, when the goal of future energy systems tends to be to reduce CO_2 as much as possible.

An additional possibility within the flexible generation category is to operate combined heat and power (CHP) systems in a flexible manner. CHP systems are heat driven system, i.e. their operation is determined by the heating demand they must cover. Nonetheless it does exist a certain degree of flexibility which can be additionally increased with heat storage systems. This option does not generate extra CO_2. CHP systems are used in the industrial sector to provide process heat, and in the household and services sectors to cover the space heating needs and produce hot water. In the industry sector the scheduling of the production can be influenced by the needs for electricity balancing [49] [50]. In the households and services sector, the flexibility comes from the implementation of thermal load management. Thermal load management relies on the fact that buildings have a thermal inertia that allows stopping the heating or increasing it for a certain period of time without having an strong impact on the comfort of its occupants [51]. In addition, in both sectors, heat storage tanks can be integrated to further increase the flexibility of CHP systems [52] [53]. Furthermore CHP for the households and services sectors has seasonal and daily profiles which are complementary to those for PV. Heating needs tend to be higher during night since buildings do not have the thermal solar gains. And they are obviously higher in winter when solar PV capacity factors are lower.

Demand side management (DSM)

There are also measures for the integration of renewable electricity which are focused on the demand side, such as demand response (DR). They are grouped under the concept of DSM [54]. DR consists in adapting the demand profile for balancing the grid. In Germany the DR potential in industry is evaluated at 2660 MW (positive reserves, i.e. capacity for load increase), which represents the 1% of the current installed generation capacity [55]. Industrial electricity consumers may decrease their load by shifting consumption, curtailing non-critical load and temporarily ceasing their production processes [56]. Nevertheless, it is important to bear in mind the large set of constraints to be respected, such as inventory levels, delivery deadlines, productions and storage capacities. All these constraints may result in a non-economic optimality of the DR implementation in some cases [57].

DR measures are also possible in the residential and services sector. They are focused on three types of consumption: electricity consumed by appliances [58], electricity for cooling services [59], and power-to-heat (P2H) for space heating and hot water [60]. In a country like Ireland with a heating dominated climate, the interruptible load for DR in the residential sector is estimated to be about 2% of the country generation capacity [61]. The potential for DR from appliances usage is assumed to be lower in the future due to their efficiency increase. In the case of electricity consumption for cooling and space heating, the decrease coming from the technology improvement will be compensated by a higher number of installed equipments [12].

The use of electricity for heat generation, named power-to-heat (P2H), allows transforming surplus electricity into heating. In addition to the flexibility for grid balancing offered by this option, it helps to decarbonize the heating supply. Furthermore, the installation of heat pumps has an investment cost about 4 to 8 times lower in comparison to the required investment to transform electricity in other energy vectors to be stored, e.g. elctrolysers [62]. Heat pumps can be installed together with heat storage tanks. Thus the amount of energy being shifted and the time that this one is moved is enhanced. Heat storage tanks are usually sized to store heat at daily level. Nonetheless some projects consider the intra-season heat storage [63]. In [64], it is demonstrated that P2H can cope with all power surplus when the renewable electricity fraction is 15%. If the fraction is further increased (7̃0%), only 25% of the surplus electricity is absorbed, the remaining must be handled by other means, such as long-term electricity storage.

Battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) can also be used for DSM if smart charging is implemented, meaning that vehicles will be charged when there will be a surplus of electricity in the grid [65]. In [66], authors claim that in 2050 in central Europe smart charging will be the main resource for reducing residual loads. Vehicle-to-grid (V2G) is another possibility offered by BEVs and PHEVs. V2G is the combination of smart charging with the possibility to use the stored electricity in the batteries of the vehicles to balance supply and demand in the electricity grid. The first studies on V2G utilisation considered it for providing peak power [67]. Nonetheless researches noticed quickly that V2G fits better into the ancillary services market: spinning reserves and regulation [68] [69]. In the ancillary services markets electric vehicles are paid to be online and available, with a complementary payment when their capacity is used [70]. Spinning reserves are operated for less than 1 hour in every call with a maximum of 20 calls per year. The systems offering spinning reserves must react within 10 minutes after being called by the grid operator. Regulation systems can be called around 400 times a day with acting times in the order of the few minutes. Regulation systems must have a reaction time below the minute [70] [71].

Long-term storage

Seasonal electricity surplus can be absorbed by long-term electricity storage options. This may offer the possibility to deliver the stored electricity during the season with possible electricity deficit. They can be classified in two categories: close-loop and open-loop systems. Close-loop systems transform the electricity surplus into another form of energy (e.g. potential, chemical) for being stored, and uses the stored energy to generate electricity when required. The consumption, storage and supply takes place at the same facility. Two examples are pumped hydro storage (PHS) and compressed air energy storage (CAES). The first one is the most mature and stablished among all possibilities for long-term electricity storage, representing 99% of the world storage capacity [72]. Nonetheless its deployment is limited by geographical constraints. Some authors claim that CAES can reach up to 89% round-trip efficiency [73], which allows them compete against PHS (about 80-85% efficiency [48]). On the opposite side, a maximum efficiency of 45% for an existing and under operation CAES plant has been reported [74]. Furthermore, some other studies show that the technology is only attractive in some scenarios with high penetration of RES [75] [76].

Open-loop technologies transform the electricity surplus into an energy vector, which reaches the market and can be traded as any other energy commodity. This is the case of power-to-gas (P2G). P2G produces hydrogen, which can be converted into synthetic natural gas (SNG) in a methanation reactor. The produced SNG and hydrogen are injected into the natural gas (NG) grid. Hydrogen can also be used in the chemical industry, or as described in appendix B, it can be used to increase the yield of Biomass To Liquids (BtL) processes. Open-loop technologies do not solve the problem of seasonal electricity deficit. Hence in the case with electricity deficit, the deployment of flexible electricity supply technologies must be considered. Nevertheless, P2G can be operated as close-loop systems if they integrate storage options such as compressing or liquifying the gases. It is important to mention that storing them brings an efficiency penalty (see section). Then it is necessary to have a technology for transforming the stored energy into electricity. Some studies propose the utilisation of reversible fuel cells - electrolysers [77].

Short-term storage

Batteries are currently not a real alternative for long-term storage due to their self discharge losses, amongst other constraints [48]. Their main role is to ensure grid stability, i.e. voltage and frequency control, by reducing short-term fluctuations thanks to their almost immediate response and high roundtrip efficiency as compared to P2G [72]. For grid storage applications further developments are needed regarding performance stability, scalability and cost reduction. Batteries should be able to stand more than 6000 cycles and have a 20 years lifetime [78]. Regarding the cost reduction, a threefold decrease is expected for the following 10 years reaching the 200 EUR/kWh [79]. Batteries are also used in smart grids energy system to reduce the electricity exchange with the grid [80] or to help to reach the self-sufficiency to isolated energy systems [81]. Some researchers have investigated the idea of reusing batteries from electric vehicles (EVs) in second-life stationary applications, such as smart grids, which could bring the battery price for the smart grid down to 100 EUR/kWh, and reduce jointly the costs of EVs [82].

Public acceptance and energy literacy

Public acceptance is a key aspect to take into consideration for the successful implementation of any national energy transition. Citizens are key decision-makers. They must decide on the policies promoting the energy transition, on their life-style and on the energy technologies that they use for transport, heating, electricity production, etc. Hence it is necessary to have well-informed citizens to avoid an amplification of some of the breaks for the energy transition, such a the higher investment cost of renewable, which would lead to a rejection of the promotion of renewable energy systems. Unfortunately, the situation is not that favourable yet. The level of energy literacy is low in our societies. In the US, a study showed that only 12% of the interviewed people could pass a basic questionnaire on energy issues. There was confusion regarding the way electricity is generated, for instance only one third could relate coal to electricity production [83]. In Canada, a survey on 505 individuals showed that participants underestimated by an average factor of 2.8 the energy consumption and energy savings of a sample of 15 activities [84].

Lobbyists and pressure groups can use the low level of energy literacy to try to modify citizens opinion on their interest. An example is the 2017 campaign for the referendum on the energy transition in Switzerland [85]. Nevertheless, citizens have the tendency to be skeptical about the message they receive from any stakeholder in the energy domain, since they are aware that these are protecting their own interests. This is why citizens are more inclined to trust information coming from academic specialists [86].

Energy specialists develop models to better understand the complexity of large-scale energy systems and help in the decision-making process. However large scale energy models are often very complex and thus inadequate for non-specialists. Hence, these models are black-boxes for citizens and policy makers. In order to bridge the gap between complexity and the level of energy literacy in decision-makers, several efforts have been made towards the development of information tools for energy scenario analysis. These tools generally allow policy makers and citizens to develop their own scenarios based on scientific data, considering both physical and technical restrictions. This way, the user gets insights into the future decisions and trade-offs in the energy puzzle.

The UK Department of Energy & Climate Change (DECC) heads the “2050 Pathways” project [87]. The core of this project is “The 2050 Calculator”, a tool giving the possibility of creating personalized UK energy pathways. The calculator is available at three levels of complexity. The calculator is complemented with a wiki including the description of the model, sources and assumptions in order to warranty the maximum transparency. The DECC also assists other countries and regions aiming at developing their own energy calculators based on “The 2050 Calculator” methodology. Up to date several countries/regions have published their 2050 Calculator (Wallonia, China, South Korea and Taiwan). This methodology has also been used for the development of an energy calculation at world level: the “2050 Global Calculator”.

“The 2050 Webtool”, the second level of complexity, is available online. On the input side, the model offers to the user 42 discrete variables to shape the pathway, these variables related to either demand or supply technologies. Despite some exceptions, it is possible to choose among four options for each variable, each of these four options representing a different evolution assumption. On the output side, the calculator displays the evolution (2010-2050) of the final energy demand, primary energy supply, electricity demand, electricity supply and CO_2-equivalent emissions. Other results are an energy flow diagram, information about energy security, required surface for renewable energies, economic cost and air quality.

At the level of Switzerland, the “ECO2-Calculator” software tool was developed [88]. This tool follows the idea that design of energy pathways requires both top-down (socio-technical) and bottom-up (individual change) approaches. Laypeople need to compare the effects of behavioural (personal efforts) and structural changes. As an input, users select values for variables/parameters that are related either to their behaviour or to external socio-technical conditions. In addition, they have the possibility to scale-up their behaviour to a Swiss level in order to see which would be the Swiss energy consumption if everyone’s energy consumption matched their own one.

As output, the “ECO2-calculator” displays the short-, mid- and long-term impacts. For the output, users can choose between energy (primary energy requirements or end energy consumption) and CO_2 emissions per year indicators.

Both “The 2050 Webtool” and “ECO2-Calculator” show only annual data. Users do not have access to monthly distributions, thus the concept of seasonal variation for supply and demand is not evident to them. Although the monthly distribution is not shown to the user, “the 2050 Webtool” outputs the number of backup power plants needed in order to guarantee electricity supply during periods of low renewable-based electricity production and high electricity demand. Predefined solutions to problems, like the use of backup power plants to balance electricity demand and supply, may play against the understanding of the energy system by users. Users might not realise the importance to close the electricity balance, since it has automatically been done by the tool.

Moreover, the final energy consumption displayed by the two tools follows the conventional division by sectors (households, services, industry and transportation). This representation of the final energy consumption does not emphasises the competition between electricity and fuels for heating and transportation end-uses, which arises from the deployment of efficient technologies such as heat pumps (HP) and electric vehicles (EV).

At institutional level, SuisseEnergie [89] offers online applications for estimating individual energy consumption for space heating, hot water, electricity and transport. These tools allow users to compare their situation with respect to the Swiss average and give some recommendations for reducing the energy consumption, but without providing any information on large-scale energy scenarios and energy policy.

Research question and overall approach

This thesis analyses and contributes to overcome the presented constraints on the integration of renewable energy systems. Four main questions are arised which we intend to answer through the methodological contributions proposed in three chapters. The research questions and chapters are:

Chapter 1 - Modelling large scale energy system, a use focused approach
1st Research question: "*How can we increase energy literacy among decision-makers?*"
Online web-tools, and more precisely online energy calculators, can be developed to increase the level of energy literacy and support decision-makers to answer their questions on the energy transition. We propose a new modeling approach in this chapter for this purpose. We have implemented the modeling approach in the Swiss-Energyscope calculator [90]. The model presented in this chapter is the calculation engine of the Swiss-Energyscope calculator. The Swiss-Energyscope caluclator is part of the Swiss-Energyscope platform [91], developed by the Energy Center and the IPESE group of EPFL to spread energy literacy and help citizens to understand and contribute to the debate about the Swiss energy strategy.

2nd Research question: "*What is the cost of the integration of new renewable energy sources?*"
In order to answer this quesiton we propose a calculation approach for calculating the total cost of any large-scale energy system. It covers all cost components (CAPEX and OPEX) the cost of the entire energy system. In this way, we avoid to spread the wrong message by focusing only in some part of the energy system, like it may happen if only the power sector

and the levelised cost of electricity are considered. That approach is also implemented in the mixed-integer linear programming (MILP) models used in chapters 2 and 3.

Chapter 2 - Optmising biomass utilisation in large scale energy systems
3rd Research question: "*How can we optimise the use of biomass?*"
Biomass is a renewable resource with a limited potential. In this chapter we use optimisation techniques to investigate the best possible biomass use. Firstly, a novel methodology is defined to compare biomass conversion options taking into account the complete bio-energy conversion pathway. The comparison is performed by evaluating the CO_2 abatement potential of integrating these different pathways into a national energy system with a Mixed-Integer Linear Programming (MILP) modelling approach. Secondly, the model presented in chapter 1 is connected to an evolutionary optimisation algorithm to explore the role of woody biomass in the Swiss energy system in 2050.

Chapter 3 - Investigating flexibility and storage options in the energy transition scenario
4th Research question: "*Which are the best alternatives for dealing with the variability of the electricity supply from renewable sources?*"
In order to answer this question, we have developed a MILP model for a national energy system with an hourly time resolution. The model considers a large set of possibilities for the integration of renewable electricity, such as smart charging for electric vehicles (EVs), power-to-gas (P2G), flexible combined heat and power (CHP) and power-to-heat (P2H) thanks to the implementation of thermal storage in buildings.

In order to test the methodologies and tools, that we have developed, we have used Switzerland as a case study. In chapter 1, the model is used to reproduce and evaluate the wider impacts of two scenarios proposed by the Swiss Federal Office of Energy (SFOE) for Switzerland in 2050. In chapter 2, over 50 woody biomass conversion pathways are evaluated in the framework of the Swiss energy system in 2035. And in chapter 3, the effects of the implementation of smart charging for EVs,P2G and flexible P2H and CHP in the Swiss energy system in 2035 is studied.

Besides having been tested on the Swiss energy system, the developed analytical framework and methodologies are sufficiently generic to be applied to other energy systems. A prove of that is the Vaud-Energyscope calculator, which is an adaptation of the Swiss-Energyscope calculator to the Canton of Vaud. This calculator was a project developed concurrently with this thesis. The Vaud-Energyscope calculator has become the reference tool for the development of the cantonal energy strategy.

Scientific publications

Chapter 1 and chapter 2 of this thesis are based on 4 scientific publications:

> **Chapter 1** corresponds to the research we have presented in the following publications: "Strategic energy planning for large-scale energy systems: A modelling framework to aid decision-making" [92] and "Exergy assessment of future energy transition scenarios with application to Switzerland" [93].
> **Chapter 2** is composed from the research present in 'Optimal use of biomass in large-scale energy systems: Insights for energy policy" and "On the Assessment of the CO2 Mitigation Potential of Woody Biomass" [94].

Finally chapter 3 contains work that authors still did not have the opportunity to publish.

The Swiss energy system

Switzerland has embarked in an energy transition. Although autonomous on a yearly balance, the country today already relies on electricity imports to face higher demand in winter months. Switzeralnd's governmental decision to phase out nuclear power plants by 2034 [17], which accounted for about 40% of its electricity production [95], will have for consequence a further increase in the seasonal energy deficit, raising as well issues related to energy security. Furthermore, it is expected that electricity consumption might increase by up to 30% by 2050. Hence solutions allowing to replace the nuclear share in the electricity mix and being able to cope with the possible increase in demand must be found. Also bearing in mind that Switzerland has engage itself to reduce its greenhouse gas (GHG) emissions by signing the Paris Agreement.

Today Switzerland consumes approximately 250 TWh of final energy, of which 24% as electricity. One third of this energy is used by the transport sector, one third is dedicated to space heating and the remaining third is shared to produce hot sanitary water, heat for industrial processes, and as electricity for lighting, appliances, any kind of electronics and IT systems. The current repartition is expected to change, as the electricity share in the energy consumption mix will raise. This is explained by the fact that efficient technologies, such as heat pumps (HPs) and battery electric vehicles (BEVs), will replace conventional fossil fuel based technologies.

Furthermore, the integration of new renewable energy sources will be mainly grounded on the deployment of renewable electricity technologies, since they are the ones presenting the largest untapped potential. PV potential is expected to reach the 18 TWh by 2035 thanks to the evolution of the efficiency of the technology. Wind and small hydro can contribute with up to 4 and 5 TWh, respectively. Although having a highly uncertain potential, geothermal electricity could cover about 6 to 9% of the electricity demand by 2050. The big hydro is not expected to have a substantial increase in its production since its potential is already well exploited in Switzerland. For heating and electricity generation, biomass has an unexploited potential of 12 to 18 TWh. The potential for solar thermal panels is not contemplated since in the future, a the combination of PV panels and HPs will be more efficient than the solar thermal panels.

The efficiency measures will also play a key role for limiting the future CO_2 emissions. In the most optimistic scenario, an increase in the thermal insulation level of the buildings park in Switzerland is expected to bring down the space heating requirements by a factor 5 in 2050 if compared to 2010 values. Some similar will happen in the industry sector, which will go from consuming 0.34 $kWh/CHF_{produced}$ to 0.15 $kWh/CHF_{produced}$ in average by 2050.

The SFOE proposes three scenarios for the energy transition until 2050 (ordered from the most pessimistic to the most optimistic):

- Business as usual (BAU)
- Political measures of the Federal Council
- New energy policies (NEP). This scenario proposes the stronger measures in terms of energy efficiency, and the biggest integration of renewable energy technologies. The NEP scenario is the one that the Energy Strategy 2050 intends to follow.

The BAU and NEP scenarios are compared in chapter 1.

All the information gathered in this subsection is contained in [31].

Terminology and conventions

The conventions in the equations presented throughout this thesis are that parameters are written in italic (“*temperature*”), variables (“**power**”) in bold and sets in all capital letters (e.g. “DAYS”).

Along this thesis, with an special importance on the “Authour’s contribution, a summary” and “Conclusions” sections, the pronoun *“we”* is used to present the work performed by the author. The first person of the plural has been chosen over the first person of the singular, since during completion of this thesis there have been a large number of interactions between colleagues, master students and external partners, which has had an influence on the developments and results discussed in this manuscript. This fact is demonstrated by the list of coauthors in the publications presented in the “Scientific publications” section.

1 Modelling large scale energy system, a decision-maker focused approach

1.1 State of the art

Climate change and security of energy supply are among the key challenges modern society is facing. As a result, a considerable effort has been made in order to gather a better understanding of the energy sector. A large number of techno-economic models for national energy systems have been developed [96]. Techno-economic energy models simulate the configuration and operation of a given energy system, investigating trade-offs between energy efficiency, cost and emissions.

In literature the words “tool", “model", “modelling framework" and “model generator" are used interchangeably to refer to these models. Nonetheless, [97] states that “an energy model is a simplified representation of a specific energy system, whereas a tool, modelling framework or model generator refers to the computer program enabling the creation of various models". From the authors’ point of view, a modelling framework is the methodology applied for the development of the model. This methodology can be adapted to countries or cities to respectively develop national or urban energy model. The word “tool" refers to the type of interaction between users and the model. Users select the tool depending on the question they want to answer.

Based on the performed literature review a classification of models and tools is proposed. Models can be divided into two categories: “evolution" and “snapshot". Evolution energy models analyse the evolution of a national energy system over a time horizon. The time horizon extends from the initial year to the end year and is broken down into a series of multiple-year or single-year periods. Each period is in turn subdivided into time-slices. Time-slices represent time intervals with similar conditions (i.e. weekends in winter, Monday mornings in summer, etc), with the purpose of better capturing seasonal, weekly or daily variations in energy supply and demand. Chronology is not taken into account in the use of time-slices. Despite the use of time-slices, one of the gaps of this type of model is that the concept of seasonal variation for supply and demand cannot be clearly studied as output data are aggregated to an annual level. Also, the implementation of technologies for heat and electricity storage cannot be investigated due to the lack of connection between the time slices. Three representative models of this category are MARKAL [98], OSeMOSYS [99] and 2050 Pathways model [87].

Snapshot models are used to evaluate the energy system configuration and operation over a timespan. “Energy system configuration" refers to the key characteristics of a national energy system, i.e. mix of technologies for electricity and heat supply, building stock, among others. The configuration of the energy system remains unchanged over the considered time span. The most common duration for the time span in one year, which is divided into chronological time-steps of one hour or less. Two examples of this type of models are EnergyPlan [51] and HOMER [100].

Tools can follow two approaches: optimisation and simulation. Often a model can be used for both purposes. Optimisation tools provide the best solution for a defined objective. MARKAL [98] and OSeMOSYS [99] are optimisation tools. Based on initial conditions and a set of assumptions (i.e. evolution of the prices of the fuels), these tools optimise the energy system evolution to meet minimum cost. The main limitation of this type of tool is that they tend to offer a solution without clearly showing the problematics of national energy systems, such as the need of back-up installed power for some renewable technologies, as it is already defined as constraint in the model. Furthermore, the optimisation is often based on economic assumptions such as fuel prices evolution [101] or investment cost [102], which tend to be highly uncertain.

Simulation tools are designed to evaluate hypothetical scenarios. They evaluate different configurations and operations of the energy system from an energetic, economic and environmental point of view. The 2050 Pathways tool [87] shows the impact of certain decisions on the evolution of UK's national energy system. The decisions are linked to several energy domains such as power supply approaches or the measures to reduce demand. EnergyPlan [51] evaluates the consequences of different national energy investments and regulation strategies.

The main shortcomings of some of these tools are the complex user interaction and the computation time. The majority of the tools for modelling national energy systems requires a training period that can vary between one day and one month [96]. This creates a barrier between the decision making tools and the decision-makers (politicians and citizens). Therefore the expert that has developed the model is typically the person in charge of building and presenting the possible energy scenarios to the decision-makers [103]. The 2050 Pathways tool [87] breaks the mentioned barrier due to its reduced number of inputs, simplified outputs and low calculation time. Furthermore it does not require any download or installation as it is available under the form of a webtool [104].

Besides the ease-of-use shortcoming, simulation tools are considered to be a better option for users that are not specialists of the energy domain in comparison to optimisation tools. The main limitation of optimisation tools is that they offer a solution without guiding users in the understanding of the problematics of national energy systems. Furthermore, the optimisation is often based on economic assumptions such as fuel prices evolution [101] or investment cost data [102], which tend to be highly uncertain. This uncertainty is very often not taken into account in the optimisation, which impacts on the reliability of the results.

Regarding the model type, the main gap of evolution models such as the 2050 Pathways model [87] is the fact that the concept of seasonal variation for supply and demand cannot be clearly studied as output data are aggregated to an annual level. Also, the implementation of technologies for heat and electricity storage cannot be investigated due to the lack of connection between the time slices. This is considered to be a key shortcoming since future energy scenarios will be characterized by high percentages of stochastic electricity sources in their electricity production mix. Snapshot models are a good alternative since they evaluate the energy system configuration and operation over a timespan. The timespan can be adapted depending on the type of time variation to be studied. Furthermore the timespan is divided into time-steps allowing for the evaluation of technologies for heat and electricity storage.

Based on the performed analysis, the authors consider that the best strategy for the development of a tool whose targeted users are not specialists of the energy domain consists in the combination of a snapshot model with a simulation tool, giving special attention to the ease-of-use of the tool and the low computation time of the model. In the performed literature review no combination of snapshot model and simulation tool respecting these characteristics has been identified.

1.2 Author's contributions, a summary

The goal of the work that we present in this chapter is to develop a model for a tool supporting decision-making at public level. The tool consists of an online energy calculator for the case of Switzerland, called Swiss-Energyscope. The tool belongs to the simulation category. The main users of the tool are expected not to be specialists of the energy domain, but rather decision-makers (policy maker, voters). Thus it allows users to test their convictions as well as to verify convictions from others, in a user-friendly approach while retaining a high degree of scientific rigour which makes Energyscope a genuine decision making tool.

Section 1.3 describes the modelling approach we have developed to construct the model. The modelling approach consists of the definition of the key methodological assumptions, inputs and key performance indicators of the model, the model structure, information and data flow.

The goals and innovative aspects of the developed modelling approach follow from the gaps identified in the literature:

- Achieving a general formulation allowing adaptation to any regional or national energy system.
- Modelling of the energy system in a holistic way, including all sectors of supply and demand.

- Showing the effect of choices on the key performance indicators of the energy system without proposing a specific solution.
- Favouring ease-of-use by a low number of input variables.
- Allowing change of input variables in any sequence without the need of introducing iteration loops.
- Keeping a low computation time of the model.
- Emphasizing the issues related to the seasonality of some resources.

Section 1.4 depicts the model and the sub-models in detail, highlighting the main assumptions and formulas in order to ensure reproducibility. We use this model in section 1.5 to analyse and compare three Swiss energy scenarios for 2050.

1.3 Modelling approach

The quality of the modelling approach is directly proportional to the degree of simplification that is possible to achieve, while retaining sufficient scientific rigour. Key challenges to face in this regard are the choice of the level of detail, the identification of the key variables impacting the system, the definition of the model structure, the distinction between the demand and supply, the inclusion of technologies producing or requiring both heat and electricity (e.g. heat pumps and cogeneration).

In the following paragraphs only the energy model is considered, while the cost, environmental impact and exergy calculations are described in the dedicated sections presenting the sub-models.

The user's inputs into the energy model are divided into five categories:

- General: macro-economic (population, economic growth) and behavioural (eco-friendly behaviour) variables.
- Efficiency: energy efficiency in buildings, industry, appliances, lighting.
- Transport: defining the share between transportation technologies, as well as the penetration of public transportation, of freight trains and of biofuels.
- Heating and CHP: allowing the choice between centralized and decentralized heating systems, and also of the technology and fuel mix for both cases.
- Electricity: installed power of renewable and non-renewable electricity production power plants.

The full list of input variables is available in Table 1.1, specifying for each input the meaning, the units and the allowed values. The table also includes inputs belonging to the "Cost" category, which will be described in section 1.4.5.

Figure 1.1 shows the conceptual modelling approach, i.e. how information flows across the model structure from the inputs to the output graphs. The energy related part of the model is structured into four sub-models: end-uses demand, transport, heating and CHP, electricity supply. The main feature of the modelling approach is the sequential flow of information across the various sub-models.

The “End-uses demand” sub-model calculates the end-uses energy requirements for heating and electricity in the household, industry and service sectors, based on the inputs belonging to the categories “Efficiency” and “General”.

The heating end-uses demand is the input into the “Heating and CHP” sub-model, which translates these end-uses into fuel consumption, electricity demand (from heat pumps and direct electric heating) and electricity production (from CHP plants), based on the input choices in the category “Heating and CHP”.

The “Transport” sub-model calculates the end-uses demand for transportation based on the “General” inputs, and translates it into fuel and electricity demand taking into account the input of the “Transport” category.

Table 1.1 – Model input variables.

Category	Input	Description	Units	Values 2035	2050
General	Population (Pop)	Number of inhabitants.	[Million inhabitant]	[7.80;9.80]	[7.20;10.70]
	Economic Growth	GDP increase rate per year: the rate of GDP increase is constant over the years.	[%]	[0.00;3.00]	
	Ecofriendly Behaviour	An increase reduces the passenger transport demand and the inhabited surface per capita.	[-]	[1.00;3.00]	
Efficiency	Building: specific demand (SpD)	Annual average heating demand per unit of inhabited surface .	[kWh/m^2]	[41.00;57.00]	[21.00;43.00]
	Industry:specific demand (SpD)	Average energy consumption of the industry for producing an amount of goods equivalent to 1 CHF.	[kWh/CHF]	[0.20;0.25]	[0.15;0.20]
	Appliances: specific demand (SpD)	Annual average electricity consumption of the appliances in a household.	[kWh/household]	[2429.00;2661.00]	[2436.00;2851.00]
	Lighting: specific demand (SpD)	Annual average electricity demand per unit of illuminated surface.	[kWh/m^2]	[0.60;0.90]	[0.40;0.60]
Transport	Vehicle fleet for passengers ($ptFleetPer_i$)	5 input variables summing 100% that define the vehicle fleet composition. Each input variable represents one type of vehicle.	[%]	[0.00;100.00]	
	Public transport use	% of the passenger transport demand covered by public transport.	[%]	[10.00;70.00]	
	Biofuels	% of the transport fuel demand that is supplied with biofuels.	[%]	[0.00;100.00]	
Heating and Combined Heat&Power	Heat for industry ($TechPer_{Ind,k}$)	3 input variables summing 100% that define the technology mix. Each input variable represents one technology.	[%]	[0.00;100.00]	
	Heat for buildings: Centralized or Decentralized($GroupPer_{Cen}$),($GroupPer_{Dec}$)	% Repartition between centralised and decentralised technologies.	[%]	[10.00;70.00]	
	Heat for buildings: Centralized technologies ($TechPer_{Cen,k}$)	4 input variables summing 100% that define the technology mix. Each input variable represents one technology.	[%]	[0.00;100.00]	
	Heat for buildings: Decentralized technologies ($TechPer_{Dec,k}$)	7 input variables summing 100% that define the technology mix. Each input variable represents one technology.	[%]	[0.00;100.00]	
	Energies ($EnPer_l$)	5 input variables for defining the energy mix used in the heating and CHP technologies.	[%]	[0.00;100.00]	
Renewable Electricity	Solar photovoltaic	Solar photovoltaic installed power.	[GW]	[0.00;24.00]	
	Wind	Wind turbines installed power.	[GW]	[0.00;5.00]	
	Hydro large dam	Hydro large dams installed power.	[GW]	[8.08;8.52]	
	Hydro run-of-river	Hydro run-of-river installed power.	[GW]	[3.84;4.69]	
	Deep geothermal	Deep geothermal installed power.	[GW]	[0.00;0.70]	
	Seasonal storage	Use of the power-to-gas technology: 0 ≡ no use of the technology, 1 ≡ All surplus of electricity is stored.	[-]	[1.00;3.00]	
Non-renewable Electricity	Nuclear	Nuclear plants installed power.	[GW]	[0.00;10.00]	
	Gas power plant	Combined cycle gas turbine installed power.	[GW]	[0.00;10.00]	
	Coal	Coal power plant installed power.	[GW]	[0.00;10.00]	
	CO_2 storage	Use of the CO_2 capture and storage technology in fossil power plants. 0 ≡ None, 1 ≡ All.	[-]	[0.00;1.00]	
Cost	Fuel prices	It determines the fuel prices evolution. An increase represents higher fuel prices.	[-]	[1.00;3.00]	
	Investment cost	It determines the specific investment cost evolution. An increase represents higher specific investment cost.	[-]	[1.00;3.00]	
	Interest rate	It determines the interest rate for the investment annualization. 1 ≡ 1.73% and 3 ≡ 4.70% .	[-]	[1.00;3.00]	

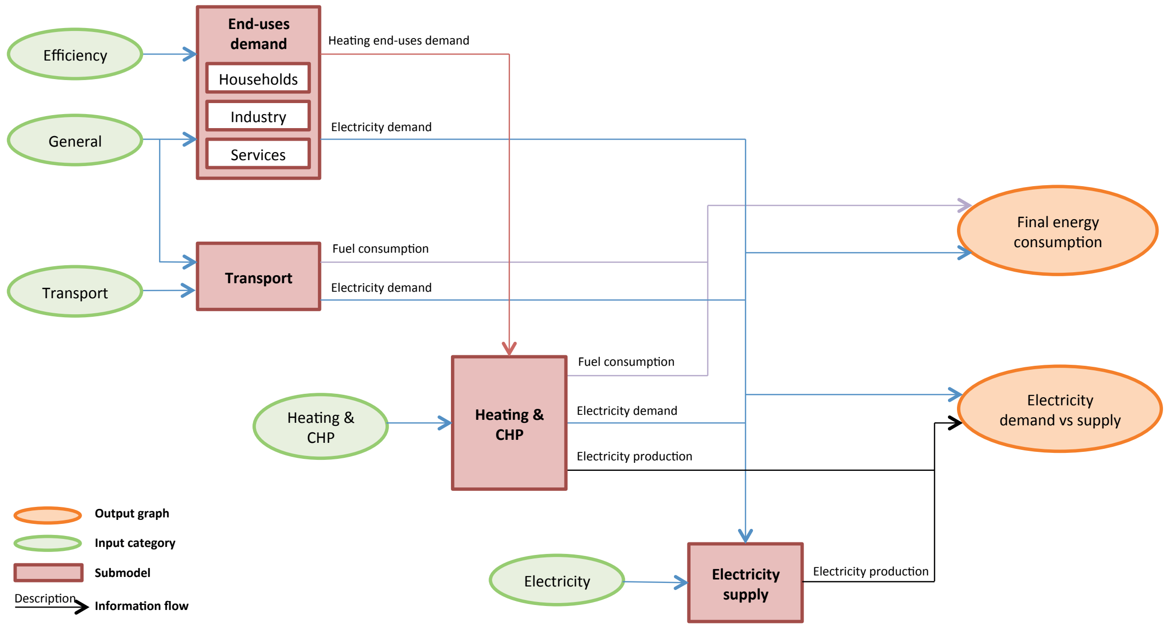

Figure 1.1 – Conceptual modelling approach: sequential flow of information across the four sub-models

The “Electricity supply” sub-model calculates the electricity production from the installed technologies as defined by the “Electricity” inputs. Although the electricity demand and supply are independently defined, the electricity demand is also taken into account by this model in order to define the operation of Natural Gas fired Combined Cycle (NGCC) power plants, as further detailed in section 1.4.4.

The sequential approach presents several advantages.

First, a distinction is introduced between modelling demand and supply. Energy demand modelling concerns the definition of the end-uses, i.e. the requirements in energy services (e.g. mobility, heating, etc). Energy supply modelling concerns the choice of the energy conversion technologies to supply these services, and it is therefore related to the final energy consumption. Based on the technology choice, the same end-use energy requirement can be satisfied with a different final energy consumption, depending on the efficiency of the chosen energy conversion technology. In the presented methodology this distinction is also made clear in the input categories in such a way that “General” and “Efficiency” inputs influence demand modelling, while the other inputs (e.g. installed PV capacity) affect only the supply side. This allows decision-makers to understand that actions can be taken on both the supply and demand sides of the energy system.

Second, some technologies may affect more than one of the three components of the final energy consumption (electricity, heating and transportation). These technologies, such as heat pumps, cogeneration, and electric cars, can be difficult to include in an energy model, since a change in the associated inputs would cause a change in the other sub-models. A solution to this problem can be the automatic balancing of supply and demand, or forcing a sequentiality in the model inputs. The first option, for example, is used in the DECC energy model. The sequential model approach has the advantage of avoiding these options, simplifying the model and allowing a greater level of control to the decision-maker.

An additional advantage is that, in this framework, electricity is left as a free variable, therefore automatic balancing of supply and demand is replaced with the possibility of having a deficit or an oversupply in the electricity sector. This is an asset for decision-makers in countries facing seasonal deficit problems, as it is the case of Switzerland and of various other countries.

1.3.1 Key performance indicators

The modelling approach proposes seven key performance indicators (KPIs): final energy consumption, electricity demand and supply, energy sources, CO_2 emissions, deposited waste, cost and exergy consumption. Each one of the KPIs are displayed in bar charts showing the main contributors in each case. In order to facilitate the reading of section 1.4, special attention is paid to the final energy consumption and the exergy indicators in this section.

The classical representation of a country's final energy consumption as the sum of the four main sectors (households, services, industry, transportation) is replaced by a tripartition into electricity, heating and transportation. This distribution has the advantage of highlighting the competition between electricity and fuels for heating and transportation end-uses.

The final energy consumption is divided into eleven entries, which are:

- Waste heat: is the waste heat from thermal power generation. It is well known that when electricity is produced from various fuels only one part of the resulting thermal power can be converted into electricity. In this calculator the waste heat corresponds to the difference between the lower heating value of fuel consumed and the electricity produced. The waste heat related to electricity import is also taken into account. In the particular case of Switzerland the model assumes that the average energy efficiency of conventional thermal electricity production in the EU-25 is 38.2%. If useful heat is considered (cogeneration), the average energy efficiency rises up to 47.8% [105]. As mentioned before this final energy consumption component was originally introduced to better illustrate the influence of cogeneration when comparing scenarios, without having to use the concept of exergy in the original version.
- Transportation: lower heating value of the fuels that are used in the transportation sector.
- Industry (th.): heat supplied by industrial cogeneration systems and lower heating value of

the fuels used in boilers for industrial processes.

- Hot water (th.): heat for sanitary hot water supplied by cogeneration, solar or geothermal heat; and lower heating value of the fuels used in boilers for sanitary hot water production.
- Space heating (th.): heat for space heating supplied by cogeneration, solar or geothermal heat; and lower heating value of the fuels used in boilers for space heating.
- Transport (el.): Electricity that is consumed in the transportation sector (train and other electric vehicles).
- Industry (el.): Electricity that is consumed in industrial processes, for either heating through direct electric heating or producing work (engines).
- Hot water (el.): Electricity that is used for producing sanitary hot water through direct electric heating.
- Heat pump (el.): Electricity that is consumed by the heat pump, which mainly provide heat for hot water and space heating.
- Space heating (el.): Electricity that is used for space heating by electric direct heating.
- Other (el.): Electricity that is consumed for other purposes that have not been previously mentioned such as lighting, cooking, IT, ventilation and air-conditioning systems, etc.. In other words uses for which electricity is not in competition with other forms of final energy.

1.3.2 The exergy indicator

Even if the interest of the concept of exergy has been known by thermodynamicists [106] for many years it is not yet recognized by the major groups of policy makers planning energy strategies. Exergy efficiency, as one of the sustainability indicators, was introduced in a simplified form in a local law on energy [107] to provide guidance to planners of heating and cooling systems. However it did not yet percolate to broader areas. Energy transition scenarios are being studied in many countries, but they usually do not refer to the concept of exergy. In the proposed indicator for final energy consumption, exergy is not directly mentioned. However it is indirectly introduced by adding the waste heat from power plants to the statistics of final energy use in the country. Adding the waste heat to the electricity production of centralized power plants producing only electricity is like extending the system boundary to consider the fuel heating value input to these plants. It is a way to be able to see, in future scenarios, the benefits of a better use of these fuels in cogeneration units for example. Since for most fuels the heating values are closed to the exergy values the approximation is tolerable.

Proper indicators are essential to be able to judge on progress, in other words, on how good technologies or policies are to achieve a better use of resources in a modern society. Only an exergy indicator allows to appreciate inefficiencies, such as using a high quality fuel like natural gas to provide an space heating service at 40°C. First Law efficiencies just cannot do a good job in this context. It is interesting to note that Switzerland used a First Law efficiency in detailed annual reporting from

1972 to 1997 (see Figure 1.2).

However the Swiss office of energy decided to abandon this statistic after 1996, since they realized that they had more and more difficulties to explain that, in spite of energy conservation efforts, this First Law indicator was dropping from year to year. This drop was showing the shift in modern societies from pure combustion for heating purposes in fuel boilers to more modern energy uses of fuels and electricity for transportation, mechanical work and communication. Even though graphical representations using Grassmann diagrams based on exergy, instead of Sankey diagrams based on energy, have been known since many years as shown for the swiss energy system of the year 1974 (see Figure10.44-45 in [106]), they are not yet very common. Note that some authors use the term "Sankey exergy" instead of Grassmann. Similar comparisons of diagrams exist for other countries like in reference [108] for Canada or US-UK [109].

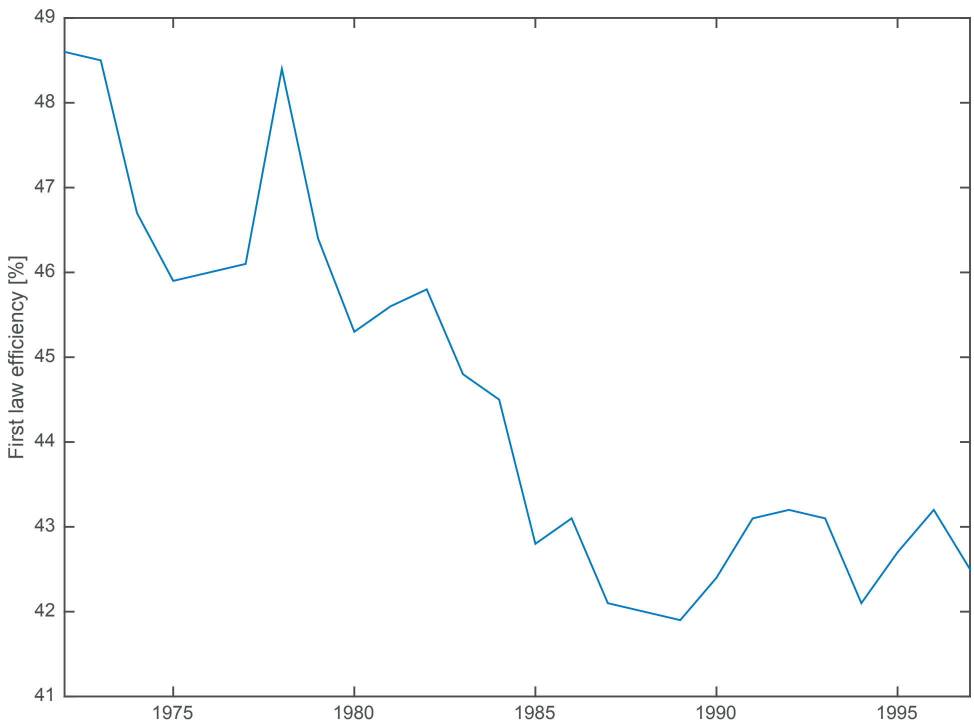

Figure 1.2 – First Law efficiency evolution from Swiss early statistics [4]. The observed drop in spite of energy efficiency efforts lead to the abandon of this statistic after 1996.

1.4 Model description

As introduced in section 1.1, the model falls into the "snapshot" category. The model evaluates different energy system configurations for a target year (2035 or 2050). The time horizon is one year divided into 12 time steps (months). The use of time steps rather than time-slices allows the implementation of technologies for electricity storage. The model has been developed on Microsoft Excel™. Table 1.2 contains the nomenclature used for the description of the model.

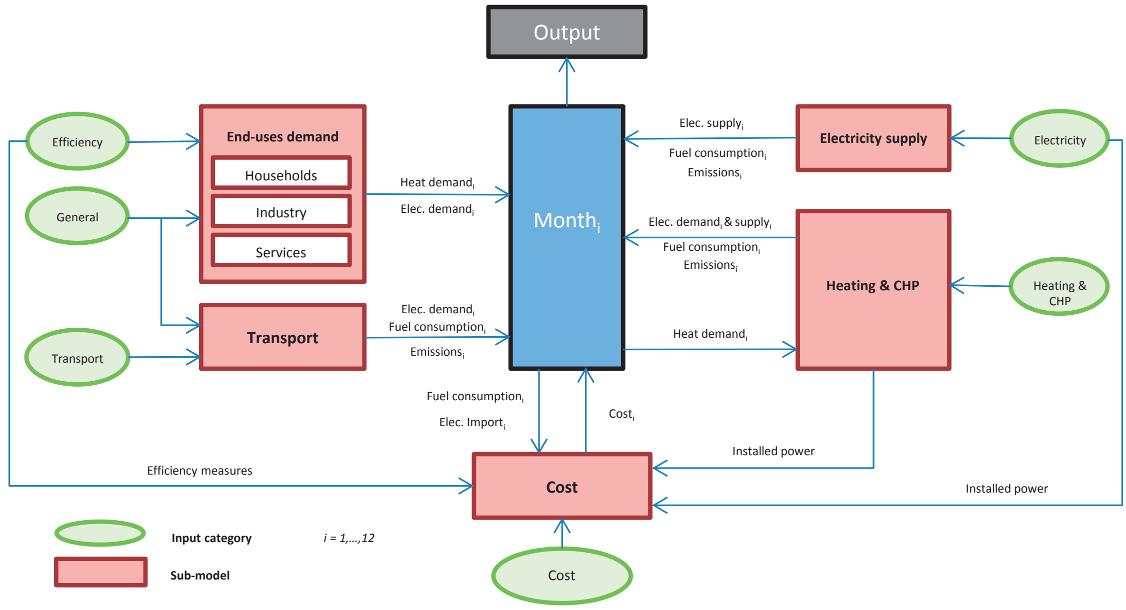

Figure 1.3 – Model structure

1.4.1 End-uses demand sub-model

The "End-uses demand" sub-model computes the electricity and heat demand for the households, industry and services sectors. The inputs for this model fall into the General (population, economic growth and eco-friendly behaviour) and Efficiency (building, industry, appliances and lighting specific demands) categories.

The model is based on data from a report commissioned by the Swiss government [12]. The report presents three energy scenarios for Switzerland: "Business as Usual" (BAU), "Political Measures of the Federal Council" (PMF) and "New Energy Policies" (NEP). These three scenarios represent the evolution of the Swiss energy sector from 2010 to 2050, sharing common assumptions about population and economic growth. They consider different evolutions for efficiency in each sector, "New Energy Policies" being the scenario with the highest effort in terms of specific energy demand reduction, and "Business as Usual" presenting the most conservative hypotheses. The values of specific energy demand assumed by these two scenarios have been used to respectively define the minimum and maximum limits for the "Efficiency" inputs.

Table 1.3 contains the six types of energy demands (k) considered in the model, together with the sector they belong to (j). The "Specific Demand" column shows which specific demand from the

Table 1.2 – Model nomenclature. In this particular case the italic format does not necessarily indicate that the entry is a parameter, since some of the entries in the table are used as both parameter and variable in the model.

Variable/Paramater	Description
$D_{j,k}$	Annual energy demand of type k in sector j
SpD_k	Specific energy demand for energy demand type k
GDP	Gross Domestic Product
Pop	Population
Sf	Inhabited surface percapita
$SpaceHeating_i$	Heat demand for space heating for the three sectors in month i
$HotWater_i$	Heat demand for hot water for the three sectors in month i
$ProcessHeat_i$	Process heat demand for the industry sector in month i
$Engines_i$	Electricity demand for engines for the industry sector in month i
$Lighting_i$	Electricity demand for lighting for the three sectors in month i
$OtherElec_i$	Electricity demand for other uses for the three sectors in month i
$BusCoachDemand$	Annual passenger transport demand to be covered by bus & coach
$ptBus_i$	Annual passanger transport demand for bus&coach with power train i
L	Heating load
P	Installed power
$Group_j$	Percentage of total installed power for the technology group j
$Tech_j, k$	Percentage of total installed power for the technology k of group j
$TechFuel_{j,k,l}$	Percentage of total installed power for the combination of group j, technology k and energy vector l
$HeatI_{i,k,l}$	Heat supplied by technology k with energy vector l during month i in industry sector
$HeatC_{i,m}$	Heat supplied by combination of technology m during month i
$PowerC_m$	Installed power of the combination of technology m
$Price_i$	Price for fossil fuel in year i
C	Economic cost in CHF
i	Interest rate
n	Lifetime in years
E	Emissions

Table 1.3 – Specific demand for the interpolation of each demand and sector to whom each demand belongs.

Demand type (k)	**Specific Demand** ($\mathbf{SpD_k^{in}}$)	**Sector** (j)
Space Heating (Sh)	Building: specific demand	Households, Industry and Services
Process Heat (Hw)	Industry: specific demand	Industry
Engines (En)	Industry: specific demand	Industry
Lighting (Li)	Lighting: specific demand	Households, Industry and Services
Other Electricity (Oe)	Appliances: specific demand	Households, Industry and Services

input ($\mathbf{SpD_k^{in}}$) is used in Eq. (1.1) for calculating each $\mathbf{D_{j,k}^{pr}}$.

$$\mathbf{D_{j,k}^{pr}} = D_{j,k}^{NEP} + \frac{\mathbf{SpD_k^{in}} - SpD_k^{NEP}}{SpD_k^{BAU} - SpD_k^{NEP}} \cdot (D_{j,k}^{BAU} - D_{j,k}^{NEP})$$

$$\forall j \in \{H, I, S\}, \forall k \neq Hw, k \in \{Sh, Hw, Ph, En, Li, Oe\} \quad (1.1)$$

Eq. (1.1) is used to do a linear regression between the energy demand of the two extreme scenarios ($D_{j,k}^{BAU}$ and $D_{j,k}^{NEP}$) considering the specific demand based on the input ($\mathbf{SpD_k^{in}}$). Thus the efficiency improvements in each sector are adapted to the input. For the household sector, $D_{H,k}^{pr}$ is then adapted to the population in the input ($\mathbf{Pop^{in}}$) as in Eq. (1.3). For the industry ($D_{I,k}^{pr}$) and services ($D_{S,k}^{pr}$) sectors, the demand is adapted based on the Gross Domestic Product ($\mathbf{GDP^{in}}$) as in Eq. (1.2).

$$\mathbf{D_{j,k}} = \mathbf{D_{j,k}^{pr}} \cdot \frac{\mathbf{GDP^{in}}}{GDP^{pr}} \qquad \forall j \in \{I, S\}, \quad \forall k \in \{Sh, ..., Oe\} \quad (1.2)$$

$$\mathbf{D_{H,k}} = \mathbf{D_{H,k}^{pr}} \cdot \frac{\mathbf{Pop^{in}}}{Pop^{pr}} \qquad \forall k \neq Sh \quad (1.3)$$

The space heating demand for the households sector ($\mathbf{D_{H,Sh}}$) is calculated as in Eq. (1.4). It depends on the inhabited surface per capita ($\mathbf{Sf^{in}}$), which is defined by the eco-friendly behaviour value, as shown in table 1.4.

$$\mathbf{D_{H,Sh}} = \mathbf{D_{H,Sh}^{pr}} \cdot \frac{\mathbf{Pop^{in}}}{Pop^{pr}} \cdot \frac{\mathbf{Sf^{in}}}{Sf^{pr}} \quad (1.4)$$

The outputs of the demand sub-model are the monthly heat and electricity demand ($\mathbf{HeatDemand_i}$ and $\mathbf{ElecDemand_i}$), which are two vectors containing respectively the heating and electricity demand divided by type, as in Eq. (1.5) and (1.6). The monthly values for $SpaceHeating$ are calculated using the Heating Degree Days (HDD) for Switzerland. The remaining monthly heating and electric-

Table 1.4 – Inhabited surface per capita values depending on the “Eco-friendly behaviour” value.

Eco-friendly behaviour	Inhabited surface per capita (Sf)		
	2011	2035	2050
1		67.0 [12]	69.9 [12]
2	57.7 [12]	57.7	57.7
3		46.2	46.2

ity demand values are computed taking into account the number of days of each month.

$$\mathbf{HeatDemand_i} = [\mathbf{SpaceHeating_i}, \mathbf{HotWater_i}, \mathbf{ProcessHeat_i}] \tag{1.5}$$

$$\mathbf{ElecDemand_i} = [\mathbf{Engines_i}, \mathbf{Lighting_i}, \mathbf{OtherElec_i}] \tag{1.6}$$

1.4.2 Transport sub-model

The transport sector is divided into passenger and freight transport. These two parts of the sub-model are independent from each other.

Road and rail passenger transport

The starting point for the passenger transport energy demand is the annual transport demand per inhabitant, expressed in [km/inhabitant]. This value depends on the eco-friendly behaviour input variable, as shown in Table 1.5. This is multiplied by the population to obtain the annual passenger transport demand [pkm].

Based on user input, the annual passenger transport demand is distributed among the different technologies. As shown in Figure 1.4, it is at first divided into public and private transport. The demand for private transport is distributed among different types of vehicles based on the fleet composition chosen by the user.

The public transport demand is attributed to “bus&coach”, “tram&trolley” and train. If in the target year (2035 or 2050) there is an increase of the percentage of public transport demand in comparison to 2011, 35 % of this increase is covered by train. The remaining 65 % is equally assigned to “bus&coach” and “tram&trolley”. If the percentage of public transport demand is lower than the percentage in 2011, then the reduced demand for train, “tram&trolley” and “bus&coach” is assigned based on their relative distribution in the year 2011.

The “bus&coach” can have four different types of powertrain as shown in Figure 1.4. The demand

Table 1.5 – Transport demand: values per capita for the "Eco-friendly behaviour".

Input Value	Transport demand per capita [10^3 km/inhab.] 2035	2050	Reference
1	16.4	16.7	Business as Usual scenario [12]
2	15.4	15.5	New Energy Policies scenario [12]
3	14.6	14.6	Constant demand since 2011 [12]

attributed to each powertrain ($\mathbf{ptBus_i}$) is calculated with Eq. (1.7), where m is the number of possible powertrains for "bus&coach" (diesel, hybrid diesel, CNG and H2), and $\mathbf{ptFleetPer_i}$ is the percentage for each kind of powertrain in the vehicle fleet.

$$\mathbf{ptBus_i} = \mathbf{BusCoachDemand} * \frac{\mathbf{ptFleetPer_i}}{\sum_i^m \mathbf{ptFleetPer_j}} \qquad \forall i \in \{1, \ldots, m\} \quad (1.7)$$

Once the annual passenger transport demand has been divided according to the transport mode and powertrain, it is multiplied by the fuel consumption of each technology, thus providing the fuel and electricity consumption for the on-land passenger transport sector. Table 1.7 shows the energy consumption for each vehicle and powertrain for 2010 and 2050. The 2050 energy consumption data that do not have a source have been computed with data from Table 1.6. The 2035 energy consumption data are calculated with a linear interpolation between 2010 and 2050 values, except for those that are available in [12], such as "Tram&Trolley" and Train. The fuel consumption is further divided into fossil fuel and biofuel respecting the percentage established by the user. It is assumed that the substitution of fossil fuels with biofuels does not have any impact on the efficiency of the powertrains.

The presented methodology only computes on-land transport energy consumption, i.e. it does not include flights. The quantity of km traveled by planes in the target year (2035 or 2050) is connected to the eco-friendly behaviour input. Three pre-set values have been selected: 109 km/ca [110], 97 km/ca (-15% compared to 2011) and 84 km/ca (-30% compared to 2011), which are associated to the positions 1, 2 and 3 of the eco-friendly behaviour input variable. These values corresponds to only national flights. The total fuel consumption is calculated by taking into account the Swiss population and the airplane fuel economy: 4.39 l/p100km in 2005 and 2.46 l/p100km in 2050, assuming a linear evolution [111].

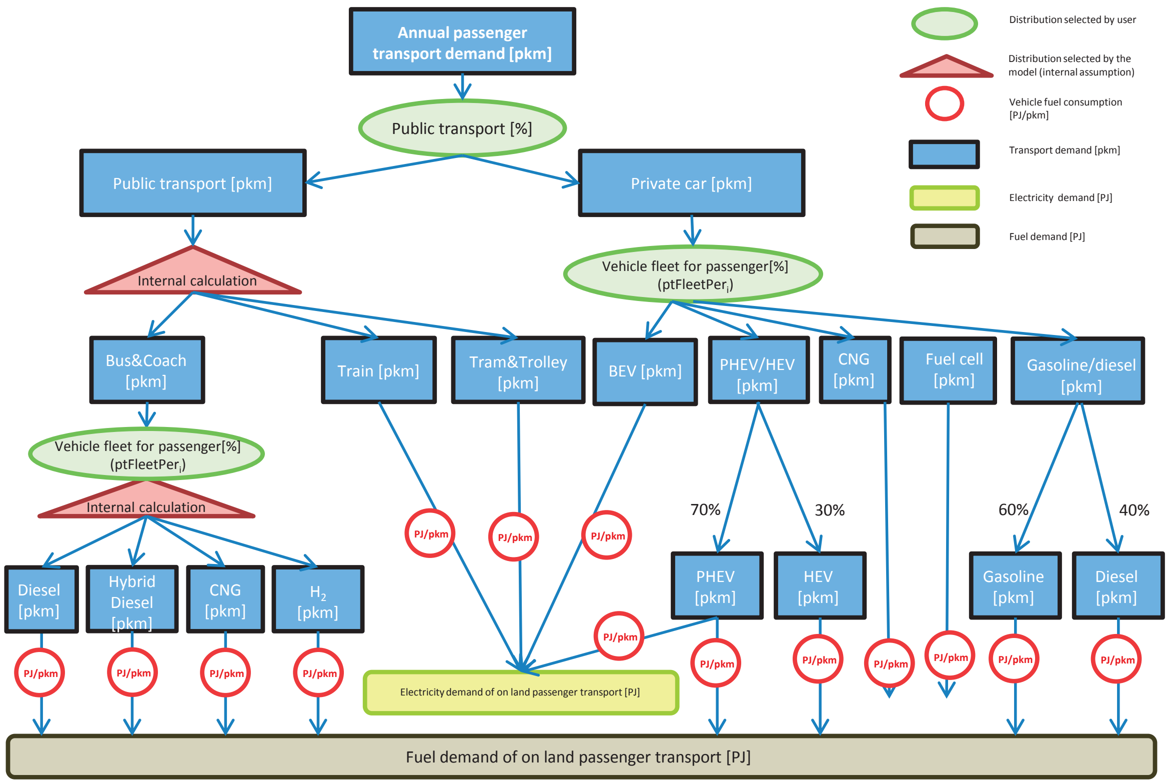

Figure 1.4 – Passenger transport model structure: Flows of information across the passengers transport model.

Table 1.6 – Fuel consumption reduction in the year 2050 compared to 2011 [9]

Powertrain	**Fuel**				
	Gasoline	Diesel	CNG	H_2	Electricity
Conventional vehicle	22.5%	19.5%	21%		
Hybrid Electric Vehicle (HEV)	27%				
Plug-in Hybrid Electric Vehicle (PHEV)	30%				30%
Battery Electric Vehicle (BEV)					23.5%
Fuel Cell Vehicle (FEV)				35.5%	

Table 1.7 – Fuel and electricity consumption for 2010 and 2050 [MJ/pkm]

Vehicle type	**2010**		**2050**	
	Fuel	Electricity	Fuel	Electricity
Gasoline conventional car	1.80 [112]		1.40	
Diesel conventional car	1.58 [112]		1.28	
CNG conventional car	2.00 [112]		1.58	
Gasoline HEV car	1.07 [113]		0.78	
Gasoline PHEV car	0.78 [113]	0.20	0.55	0.14
BEV car		0.45 [114]		0.34
FCV car	0.83 [115]		0.54	
Tram&Trolley				0.59 [12]
Diesel Conventional Bus&Coach	1.08 [112]		0.88	
Diesel HEV Bus&Coach	0.79 [116]		0.88	
CNG Conventional Bus&Coach	1.27 [117]		1.00	
FCV Bus&Coach	0.95 [116]		0.73	
Train				0.31 [12]

Freight transport

For this part of the model, only the on-land transport by train and road has been considered. The annual freight transport demand [tkm] is based on the values forecast in [12]. The value is adapted based on the Swiss gross domestic product defined by the input $\mathbf{GDP_{in}}$, as in Eq. (1.8), where $TransportFreight_{Report}$ and GDP_{Report} are respectively the annual freight transport demand and gross domestic product forecast in [12] for the target year (2035 or 2050).

$$\mathbf{TransportFreight} = TransportFreight_{Report} * \frac{\mathbf{GDP_{Calc}}}{GDP_{Report}} \tag{1.8}$$

The “Freight train” input sets the distribution between train and road transport demands. Trains are

Table 1.8 – Share and fuel consumption for trucks and vans based on their total weight (vehicle and freight weight) in 2010, 2035 and 2050

Total weight	**Share** [119]	**Fuel consumption** [MJ/tkm]		
		2011 [112]	2035 [12]	2050 [12]
< 3.5 t	6%	14.19	9.84	8.19
[3.5 t, 20 t]	42%	2.70	1.87	1.56
> 28 t	52%	1.24	0.86	0.72

considered to be only electric [118]. Their electricity consumption values for 2035 and 2050 are an average of the values forecast in [12] for the three aforementioned scenarios: 0.25 MJ/tkm in 2035 and 0.23 MJ/tkm in 2050. Road freight transport is assumed to be shared between three types of vehicles, whose shares and fuel economies are presented in Table 1.8. The distribution among the different types of vehicles is assumed to be the same for the years 2011, 2035 and 2050. To compute the fuel consumption for 2035 and 2050, data from [112] are used for 2011 and extrapolated to 2035 and 2050 assuming the same efficiency evolution as in [12]. The values are presented in Table 1.8.

1.4.3 Heating and cogeneration

The input variables for this sub-model are divided into three groups: "Heat for industry", "Heat for buildings" and "Energies". "Heat for industry" inputs define the technology mix for supplying the heat required by industrial processes. "Heat for buildings" inputs establish the combination of technologies for covering the load of space heating and hot water. "Energies" inputs determine the share of the energy vectors (i.e. fuels and electricity) for heating and cogeneration technologies. This approach is favoured over the option of letting users select the energy mix for each technology. This choice allows a lower number of inputs.

Installed power

The goal of this sub-section is to describe how the total installed power is calculated and divided among the different combinations of groups of technology, technology and energy vector that can be used for covering the heating demand in industry and buildings.

There are three groups of technologies: Industry (Ind), Centralized (Cen) and Decentralized (Dec). Each group of technologies can include up to eight different technologies: Cogeneration ($Cogen$), Advanced Cogeneration ($AdvCogen$), Heat Pump (HP), Thermal Heat Pump ($ThHP$), Boiler ($Boiler$), Solar Thermal ($Solar$), Geothermal (Geo) and Direct Electric Heating ($DirElec$). Each of these technologies can use nine different energy vectors: Gas (Gas), Wood ($Wood$), Oil (Oil), Waste ($Waste$), Coal ($Coal$), Hydrogen (H_2), Solar radiation ($Solar$), Geothermal Heat (Geo) and Electricity ($Elec$). Figure 1.5 shows the technologies included in the three groups. Each technology uses a different mix of energy vectors.

Eq. (1.9) and (1.10) calculate the heating load for buildings ($\mathbf{L_{Building}}$) and industry ($\mathbf{L_{Industry}}$), where 12 is the number of months of the year. These two values are combined in Eq. (1.11) to compute the total installed power ($\mathbf{P_T}$). Eq. (1.11) takes into account the fact that the installed solar thermal panels require backup systems with the same installed capacity. $\mathbf{TechFuel_{Dec,Solar,Solar}}$ is the percentage of total installed power for decentralized solar thermal panels.

$$\mathbf{L_{Buidling}} = \max_i\{\frac{\mathbf{SpaceHeating_i} + \mathbf{HotWater_i}}{Days_i \cdot 24}\} \qquad i \in \{1,...,12\} \quad (1.9)$$

$$\mathbf{L_{Industry}} = \frac{\sum_{i=1}^{12} \mathbf{ProcessHeat_i}}{365 \cdot 24} \quad (1.10)$$

$$\mathbf{P_T} = \frac{\mathbf{L_{Industry}} + \mathbf{L_{Building}}}{1 - \mathbf{TechFuel_{Dec,Solar,Solar}}} \quad (1.11)$$

The percentage for each group of technologies ($\mathbf{Group_j}$) is calculated with Eq. (1.12), where $\mathbf{GroupPer_{Cen}}$ and $\mathbf{GroupPer_{Dec}}$ are the values from the input variables that define the ratio between Centralized and Decentralized technologies for buildings. $P_{Building}$ is the installed heating power in buildings, which is equal to the sum of the heating load for buildings $\mathbf{L_{Building}}$ plus the back-up installed capacity for the solar thermal panels (see Eq. (1.14)).

$$\mathbf{Group} = [\frac{\mathbf{L_{Industry}}}{\mathbf{P_T}}, \frac{\mathbf{P_{Building}}}{\mathbf{P_T}}\mathbf{GroupPer_{Cen}}, \frac{\mathbf{P_{Building}}}{\mathbf{P_T}}\mathbf{GroupPer_{Dec}}] \quad (1.12)$$

$$\sum_j \mathbf{GroupPer_j} = 1 \qquad \forall j \in \{Ind, Cen, Dec\} \quad (1.13)$$

$$\mathbf{P_{Building}} = \mathbf{L_{Building}} + \mathbf{TechFuel_{Dec,Solar,Solar}}\mathbf{P_T} \quad (1.14)$$

The share of each technology is calculated by Eq. (1.15,1.16) , where $\mathbf{TechPer_{j,k}}$ is the value of the input variable for the technology k in the group j. If the technology k is not included in the group j, $\mathbf{TechPer_{j,k} = 0}$.

$$\mathbf{Tech_{j,k}} = \mathbf{Group_j} \cdot \mathbf{TechPer_{j,k}} \qquad \forall j \in \{Ind, Cen, Dec\}, \forall k \in \{Cogen, ..., DirElec\} \quad (1.15)$$

$$\sum_k \mathbf{Tech_{j,k}} = \mathbf{Group_j} \qquad \forall j \in \{Ind, Cen, Dec\}, \forall k \in \{Cogen, ..., DirElec\} \quad (1.16)$$

Finally $\mathbf{TechFuel_{j,k,l}}$ is calculated, where j is the group, k the technology and l the energy vector. The

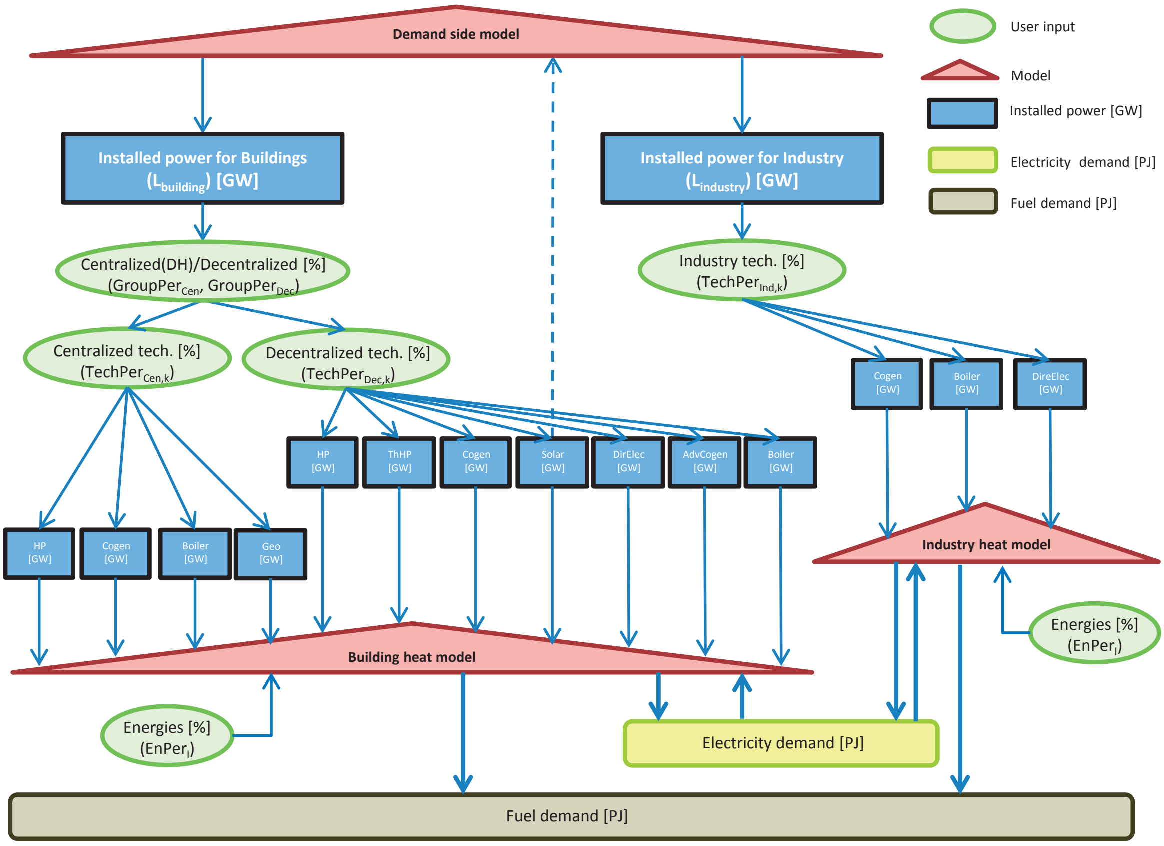

Figure 1.5 – Heating and cogeneration model structure: Flows of information across the Heating and cogeneration model.

sum of $\mathbf{TechFuel_{j,k,l}}$ over all the indices is equal to 1. The global mix of energy vectors is distributed among the different technologies, as in Eq. (1.17)-(1.25), where $\mathbf{En_l}$ is the value of the input variable for the energy vector l, and $\mathbf{C_{j,k,l}}$ is a binary variable: if $\mathbf{C_{j,k,l}} = 1$, then there is a possible combination between the group j, the technology k and the energy vector l in the model. If $\mathbf{C_{j,k,l}} = 0$, the combination is not feasible.

Eq. (1.17-1.19) is used for all combinations of groups and technologies whose fuel is natural gas or wood, except for those having Advanced Cogeneration ($AdvCogen$) and Thermal Heat pumps ($ThHP$) as technology.

$$\mathbf{TechFuel_{j,k,l}} = (\mathbf{Tech_{j,k}} - \mathbf{EnPer_{Coal}C_{j,k,Coal}} - \mathbf{EnPer_{Oil}Oil} - \mathbf{EnPer_{Waste}Waste})\cdot \frac{\mathbf{EnPer_l}}{\mathbf{EnPer_{Gas}} + \mathbf{EnPer_{Wood}}}\mathbf{C_{j,k,l}}$$
$$\forall j \in \{Ind, Cen, Dec\}, \forall k \notin \{AdvCogen, ThHP\}, \forall l \in \{Gas, Wood\} \quad (1.17)$$

$$\mathbf{Oil} = \frac{\mathbf{Tech_{j,k}C_{j,k,Oil}}}{\sum_j \sum_k \mathbf{Tech_{j,k}C_{j,k,Oil}}}$$
$$\forall j \in \{Ind, Cen, Dec\}, \forall k \notin \{AdvCogen, ThHP\}, \forall l \in \{Gas, Wood\} \quad (1.18)$$

$$\mathbf{Waste} = \frac{\mathbf{Tech_{j,k}C_{j,k,Waste}}}{\sum_j \sum_k \mathbf{Tech_{j,k}C_{j,k,Waste}}}$$
$$\forall j \in \{Ind, Cen, Dec\}, \forall k \notin \{AdvCogen, ThHP\}, \forall l \in \{Gas, Wood\} \quad (1.19)$$

75% of $AdvCogen$ systems are assumed to have natural gas as energy vector.The remaining 25% uses hydrogen (see Eq. (1.21)). The only energy vector supported by $ThHP$ is natural gas (see Eq. (1.23)).

$$\mathbf{TechFuel_{Dec,AdvCogen,Gas}} = 0.75\mathbf{Tech_{Dec,AdvCogen}} \quad (1.20)$$

$$\mathbf{TechFuel_{Dec,AdvCogen,H2}} = 0.25\mathbf{Tech_{Dec,AdvCogen}} \quad (1.21)$$

$$\mathbf{TechFuel_{j,AdvCogen,l}} = 0 \qquad \forall j, k = AdvCogen \forall l \notin \{Gas, H_2\} \quad (1.22)$$

$$\mathbf{TechFuel_{j,ThHP,l}} = \mathbf{Tech_{Dec,ThHP}C_{j,k,l}} \qquad \forall j, \forall l \quad (1.23)$$

Eq. (1.24) is used for all combination of group and technology whose energy vector is oil, waste or coal.

$$\mathbf{TechFuel_{j,k,l}} = \mathbf{EnPer_l} \frac{\mathbf{Tech_{j,k}C_{j,k,l}}}{\sum_j \sum_k \mathbf{Tech_{j,k}C_{j,k,l}}} \qquad \forall j, \forall k, \forall l \in \{Oil, Waste, Coal\} \quad (1.24)$$

Combinations of groups and technologies that have solar, geothermal heat or electricity as energy vector cannot use any other energy vector (see Eq. (1.25)).

$$\mathbf{TechFuel_{j,k,l}} = \mathbf{Tech_{j,k}C_{j,k,l}} \qquad \forall j, \forall k, \forall l \in \{Solar, Geo, Elec\} \quad (1.25)$$

$$j \in \{Ind, Cen, Dec\}, \quad k \in \{Cogen, ..., DirElec\} \qquad l \in \{Gas, ..., Elec\} \quad (1.26)$$

Eq. (1.27) calculates the installed power ($\mathbf{P_{j,k,l}}$) for each combination of group, technology and energy vector. This, together with the monthly heating requirement $SpaceHeating_i$, $HotWater_i$ and $ProcessHeat_i$ is used to calculate the supplied heat. The use of the heating and cogeneration technologies follows two different operation strategies depending on the sector (industry or building).

$$\mathbf{P_{j,k,l}} = \mathbf{TechFuel_{j,k,l}P_T}$$
$$\forall j \in \{Ind, Cen, Dec\}, \forall k \in \{Cogen, ..., DirElec\}, \forall k \in \{Gas, ..., Elec\} \quad (1.27)$$

Operation strategy in Industry

The heat supplied by each combination of groups, technologies and energy vectors during a month ($Heat_{i,j,k,l}$) is proportional to the corresponding installed power. It is calculated with Eq. (1.28).

$$\mathbf{HeatI_{i,k,l}} = \mathbf{FuelTech_{I,k,l}ProcessHeat_i}$$
$$\forall i \in \{1, ..., 12\}, \forall k \in \{Cogen, ..., DirElec\}, \forall l \in \{Gas, ..., Elec\} \quad (1.28)$$

Operation strategy in Buildings

As renewable heat source, solar thermal is assigned the highest priority. Hence monthly heating demand for buildings is defined as follows:

$$\mathbf{HeatBuilding_i} = \mathbf{SpaceHeating_i} + \mathbf{HotWater_i} - \mathbf{Heat_{i,Dec,Solar,Solar}} \qquad \forall i \in \{1, ..., 12\} \quad (1.29)$$

where $\mathbf{Heat_{i,Dec,Solar,Solar}}$ is the heat supplied by the solar thermal panels during the month i.

Boilers can be installed on their own or as peak boilers when combined with cogeneration systems and heat pumps. Cogeneration systems and heat pumps are always combined with peak boilers, representing 15% of the total power (85% $Cogen$ or HP + 15% $Boiler$). This condition is respected as long as the percentage of $Boiler$ in inputs is high enough. This approach defines 11 combinations of technologies:

- Centralized Heat Pumps + Centalized Boiler ($CenHP\_CenBoiler$)
- Centralized Cogeneration + Centralized Boiler ($CenCogen\_CenBoiler$)
- Centralized Boiler ($CenBoiler$)
- Geothermal (Geo)
- Decentralized Heat Pumps + Decentalized Boiler ($DecHP\_DecBoiler$)
- Decentralized Thermal Heat Pump ($DecThHP$)
- Decentralized Cogeneration + Decentralized Boiler ($DecCogen\_DecBoiler$)
- Decentralized Advanced Cogeneration + Decentralized Boiler ($DecAdvCogen\_DecBoiler$)
- Decentralized Boiler ($DecBoiler$)
- Decentralized Direct Electric Heating ($DecDirElec$)

The monthly heat demand ($\mathbf{HeatBuilding_i}$) is shared among these different combinations proportionally to their installed power as shown in Eq. (1.30), where $\mathbf{PowerC_m}$ is the installed power for each combination of technologies.

$$\mathbf{HeatC_{i,m}} = \mathbf{HeatBuilding_i} \frac{\mathbf{PowerC_m}}{\sum_m \mathbf{PowerC_m}}$$

$$\forall i \in \{1, ..., n\}, \forall m \in \{CenHP\_CenBoiler, ..., DecDirElec\} \tag{1.30}$$

The installed power of every combination of technologies ($PowerC_m$) is higher than the average monthly load due to the back-up power for solar thermal panels. In addition the system is sized taking into account the month of the year with the highest heat demand (see Eq. (1.9)). Therefore there is an operation strategy for the combination of technologies that include peak boilers, since the use of both technologies at full capacity would result in an excess of heat supply. The operation strategy is based on the following list of conditions, which are ordered from higher to lower priority:

1. To cover the heat demand.
2. To maximise the efficiency.
    (a) Not to produce electricity when there is no demand for it.
    (b) To maximise the use of efficient systems (heat pumps and cogeneration).

Thus, heat pumps always have preference over peak boilers. Peak boilers are only used when the heating demand cannot be covered only by heat pumps. Cogeneration and Advanced cogeneration

Table 1.9 – Electricity supply technologies: assumptions for capacity factor and seasonal distribution.

Technology	**Capacity factor**	**Seasonal distribution** [winter, spring, summer, autum]
Solar photovoltaic	0.113 [120]	[0.131, 0.318, 0.354, 0.197] [121]
Wind power	0.230 (2011), 0.250 (2035), 0.270 (2050) [122]	[0.338, 0.234, 0.155, 0.273] [123]
Hydro run-of-river	0.484 [a]	[0.155, 0.237, 0.390, 0.218] [124]
Hydro large dam	0.234 [a]	[0.256, 0.201, 0.289, 0.254] or Variable [124]
Deep geothermal	0.850 [125]	[0.250, 0.250, 0.250, 0.250]
Nuclear	0.850 [126]	[0.250, 0.250, 0.250, 0.250]
Coal	0.850 [127]	[0.250, 0.250, 0.250, 0.250]
CCGT	0.800 Max [127]	Variable

[a] See appendix A.1 for further details.

also have priority over peak boilers, as long as the electricity supplied by these systems does not contribute to an overproduction of electricity (higher supply than demand of electricity in month i). Therefore peak boilers for cogeneration systems are used under two circumstances:

- Heating demand cannot be covered only by cogeneration systems.
- The use of cogeneration systems gives an overproduction of electricity.

1.4.4 Electricity supply sub-model

Each of the "Electricity" inputs of the electricity sub-model represents the installed power of one technology. For some technologies, such as solar photovoltaic, wind power, hydro run-of-river and deep geothermal for the renewable group, nuclear and coal for the non-renewable group, the electricity production depends only on the chosen installed capacity. The monthly distribution of electricity production by these six technologies is based on pre-defined seasonal profiles. Renewable technologies, except for deep geothermal, present seasonal variations, while the two non-renewable technologies (coal and nuclear) are treated as base load supply. Table 1.9 lists the capacity factors and the seasonal distribution for these technologies.

The electricity supply by large hydro dams is also directly proportional to the installed power; however, the monthly distribution can change. The model takes into account the possibility of increasing the height of the dams. It is assumed that the storage capacity that could be gained by increasing the height of a certain number of dams in Switzerland is 2400 GWh [128]. The model input range is from 8.08 GW to 8.52 GW. The first value represents the actual installed capacity, i.e. no dam increase is accounted for, 8.52 GW corresponds to the deployment of the additional 2400 GWh storage capacity. For intermediate inputs a linear interpolation is made. The new storage capacity is used for shifting electricity production from summer to winter, reducing the need for turbining water during summer and storing it for the winter months with electricity deficit. Thus, in case of storage, the seasonal distribution could be different to the one shown in Table 1.9. A detail description on the potential of hydro river and hydro dam in Switzerland in available in appendix

A.1.

Combined Cycle Gas Turbine (CCGT) is another technology whose monthly distribution is not fixed. CCGT plants are modelled to produce electricity only if the other technologies cannot cover the electricity demand, and as long as there is enough CCGT installed power. Thus, CCGT plants do not supply electricity in case of overproduction.

Seasonal storage consists in the production of synthetic fuels from the excess of electricity. In this case the fuel is methane, which is stored in a liquid form. The efficiency and cost of the system is based on the CO_2-CH_4 closed loop presented in [77], reaching a roundtrip efficiency of 54.5%. The technology is explained in detail in appendix A.2. In this case the input does not represent the installed power, since its range is [0, 1]. If 0 is chosen, no seasonal storage is implemented, whereas if the position of the input variable is 1, all the excess electricity is converted into fuel, as long as this stored electricity can be used in other months with electricity deficit.

The CO_2 capture and storage (CCS) input concerns the CCGT and coal power plants. It has a similar definition to the seasonal storage input variable: 0 means no implementation of the technology, while 1 means that all the fossil fuel power plants use CO_2 capture. The use of CCS technologies implies lower CO_2 emissions, but the considered drawbacks are lower efficiencies, higher specific investment costs and increased deposited waste.

1.4.5 Cost sub-model

Evolution energy models calculate the investment cost as the total cumulated investment over the considered time horizon. For instance, models belonging to the TIMES/MARKAL family compute the net present value (NPV) of the installed technologies [129]. These models design installation/decommissioning pathways for each energy technology, which increases the model complexity.

On the other hand, snapshot models, like EnergyPLAN [130], calculate the investment cost as the annualised investment cost of the technology mix for the year under study. This is the approach we have implemented for the cost model. The investment cost is annualised based on the interest rate as in Eq. (1.31), where $\mathbf{C_{invT}}$ is the total investment cost, i is the interest rate and n is the technology life time in years.

$$\mathbf{C_{inv}} = \mathbf{C_{invT}} \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \tag{1.31}$$

The investment cost is calculated for each year (2011, 2035 and 2050) by assuming that the complete energy system is entirely replaced during the selected year, taking into account the relative prices and the technology development status. This assumption allows the comparison between the investment cost of 2011 with those for 2035 and 2050, and it offers two main advantages:

- There is no need to consider any installation/decommissioning pathway.
- We do not enter into the problematic of the amortisation level of the installed technologies. This is a key aspect for Switzerland since most of the existing hydro dams were built at the beginnings of the XXth century, so they have already been completely amortised. Nevertheless these dams require new important investments to maintain their performance and safety level, as well as for increasing their capacity [131]. Thanks to this assumption, we avoid performing a detailed study on the scheduling of the required future investments.

Cost parameters have a high degree of uncertainty. For instance, Moret el al. [132] demonstrate that past forecasts for natural gas prices overestimated natural gas prices by a factor 3.3. Hence the developed cost sub-model tries to capture this reality by defining three input variables that users can modify to recreate different cost scenarios. The inputs of the cost sub-model are the "Fuel Prices", "Investment cost" and "Interest rate" defined in Table 1.1. The extreme values of these three inputs are "1" and "3", with "1" assuming the lowest value for the costs, and "3" the highest values.

The "Fuel prices" input defines which of the 3 discrete price levels is selected for the cost calculation. Table 1.10 shows the production prices, or prices at the Swiss border, if the resource is imported. The "Investment cost" input determines which of the 3 levels of specific investment cost is considered. More information about the considered specific investment costs is available in [133].

The "Interest rate" input variable sets the interest rate. The defined range for the interest rate is [1.73, 4.70] %. This range is defined based on experts opinion [1]. The upper bound corresponds to the official discount rate for energy in Switzerland [134], while the lower bound is the assessed discount rate for electricity production companies in Switzerland.

Neither taxation nor gains made by energy companies are accounted for in the cost calculations. In this way, the calculated cost represents the net cost for the Swiss economy.

The prices for fossil fuels in 2035 and 2050 are calculated by Eq. (1.32), (1.33) and (1.34), taking into account the 2010 prices and the three evolution paths forecast by the European Commission [143].

$$\mathbf{Price_{2035/2050_1}} = \frac{Price_{2010} * Price_{EuropeanCommission2035/2050_{Low}}}{Price_{EuropeanCommission2010}} \tag{1.32}$$

$$\mathbf{Price_{2035/2050_2}} = \frac{Price_{2010} * Price_{EuropeanCommission2035/2050_{Ref}}}{Price_{EuropeanCommission2010}} \tag{1.33}$$

$$\mathbf{Price_{2035/2050_3}} = \frac{Price_{2010} * Price_{EuropeanCommission2035/2050_{High}}}{Price_{EuropeanCommission2010}} \tag{1.34}$$

Bioethanol and Biodiesel are considered to have the same price evolution as the fuel they substitute

[1] Email exchange with Professor Philippe Thalmann in July 2014

Table 1.10 – Prices evolutions for the different input values

		2010	2035 MIN(1)	2035 MID(2)	2035 MAX(3)	2050 MIN(1)	2050 MID(2)	2050 MAX(3)
Gasoline	ctsCHF/kWh$_{fuel}$	8.59 [135, 136]	9.18	11.30	14.76	8.55	12.90	16.51
Diesel		8.41 [135, 136]	8.99	11.07	14.46	8.38	12.64	16.18
Bioethanol		7.36 [137]	9.18	11.30	14.76	8.55	12.90	16.51
Biodiesel		11.93 [137]	8.99	11.07	14.46	8.38	12.64	16.18
Heating fuel oil		6.99 [135, 136]	8.60	11.24	6.52	9.83	12.58	
Kerosene		5.91 [138]	6.32	7.78	10.16	5.89	8.88	11.37
Gas		6.50 [139]	6.15	10.07	13.00	6.62	12.07	15.87
Wood		3.01 [12]	6.82	7.81	8.80	7.41	8.96	10.50
Coal		3.60 [140]	3.76	5.34	7.26	3.68	5.43	6.51
Nuclear fuel	ctsCHF/kWh$_e$	11.86 [141]	6.67 [141]	13.51 [141]	17.45 [141]	6.52 [142]	13.14 [141, 142]	19.48 [141]
Imported electricity		15.90 [139]	15.90	24.00	32.10 [12]	15.90	24.75	33.60 [12]

(gasoline and diesel respectively), in order to limit the number of inputs. The price for forestry wood in 2035 and 2050 is calculated following the same methodology used for the fossil fuel prices, but the evolution is based on the wood price forecasts in [12].

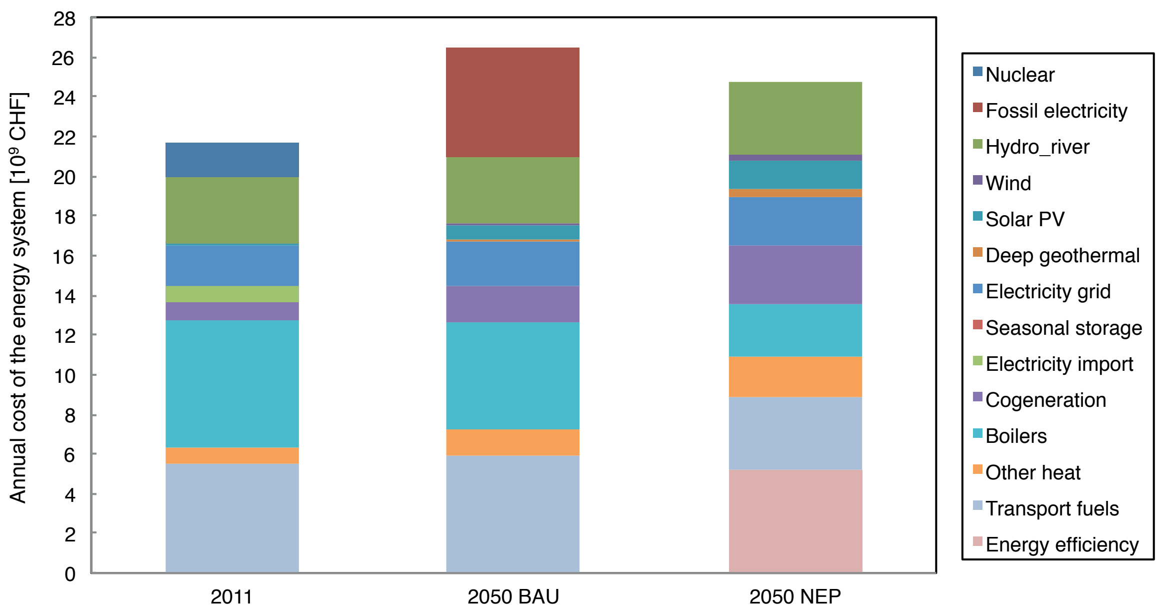

Figure 1.6 – Annual total cost for the 2050CH High(C) and 2050CH Low(E) scenarios.

The graph legend in Figure 1.6 shows the elements of the national energy system that are taken into account for computing the "Annual total cost". For each of these elements the annual total cost (**C**$_{\mathbf{TOT}}$) is calculated as shown in Eq. (1.35), where **C**$_{\mathbf{fuel}}$ is the cost of all consumed fuels and imported electricity for one year, **C**$_{\mathbf{O\&M}}$ is the annual Operation and Maintenance cost and **C**$_{\mathbf{inv}}$ is the annualised investment cost for each element. Some elements only include one cost component, e.g. "Transport fuels" has only the C_{fuel} or "Elec. Grid" with C_{inv}. In this approach, cogeneration systems are represented by a single element in the legend:"Combined Heat&Power". This avoids calculating the relative cost allocation to electricity and heat production, which is an advantage in comparison to the approaches based on the levelized cost of electricity and heat.

$$\mathbf{C_{TOT}} = \mathbf{C_{inv}} + \mathbf{C_{fuel}} + \mathbf{C_{O\&M}} \tag{1.35}$$

1.4.6 Environmental impact sub-model

The environmental impact is calculated with a life cycle assessment (LCA) approach. The LCA approach assesses the environmental impact of all the phases (mining, extraction, transformation, transport, infrastructure development, etc) needed to deliver a service or a product, including its disposal or recycling. The two selected environmental indicators are "CO_2 equivalent emissions" and "Deposited Waste". The "CO_2-equivalent emissions" is based on the "IPCC 2007 - Global Warming Potential (GWP) 100years" impact assessment method, while "Deposited Waste" corresponds to the "ecological scarcity 2006 - deposited waste" method. "IPCC 2007 - GWP 100years" method takes into account the emissions of all the gases contributing to the greenhouse effect and quantifies them as the amount of CO_2 that would have the equivalent global warming potential. The "ecological scarcity 2006 - deposited waste" method considers the volume occupied for disposal of radioactive waste and the amount of total organic carbon (TOC) dumped into the water. The unit is the "UBP" ("Ecopoint") [112].

The emissions related to electricity imports are included in the emission balances, while those attributed to the electricity exports are not subtracted. This approach complicates the comparison of the results from the models with data from other sources, as national emissions inventories are usually computed following a production based approach [144]. The production based approach only accounts for greenhouse gas emissions and removals taking place within national territories.

To facilitate this comparison the "CO_2 equivalent emissions" data are displayed as in Figure 1.7: the legend includes 7 fossil fuels (Gas, Fuel Oil, Diesel, Gasoline, Kerosene, Waste and Coal) and an entry for "Indirect emissions". The emissions included under the fossil fuel entries follow the production based approach as they derive from the combustion of fossil fuels on the national territory. "Indirect emissions" ($\mathbf{E_{ind}}$) are calculated in Eq. (1.36), where $\mathbf{E_{LCA}}$ are the emissions calculated following the life cycle approach, $\mathbf{E_{comb}}$ are the direct emissions from fuel combustion and $\mathbf{E_{ElecImp}}$ are the emissions linked to the imported electricity (calculated also with LCA).

$$\mathbf{E_{ind}} = \mathbf{E_{LCA}} - \mathbf{E_{comb}} + \mathbf{E_{ElecImp}} \tag{1.36}$$

The legend for the deposited waste follows a different approach. The legend contains 9 entries:

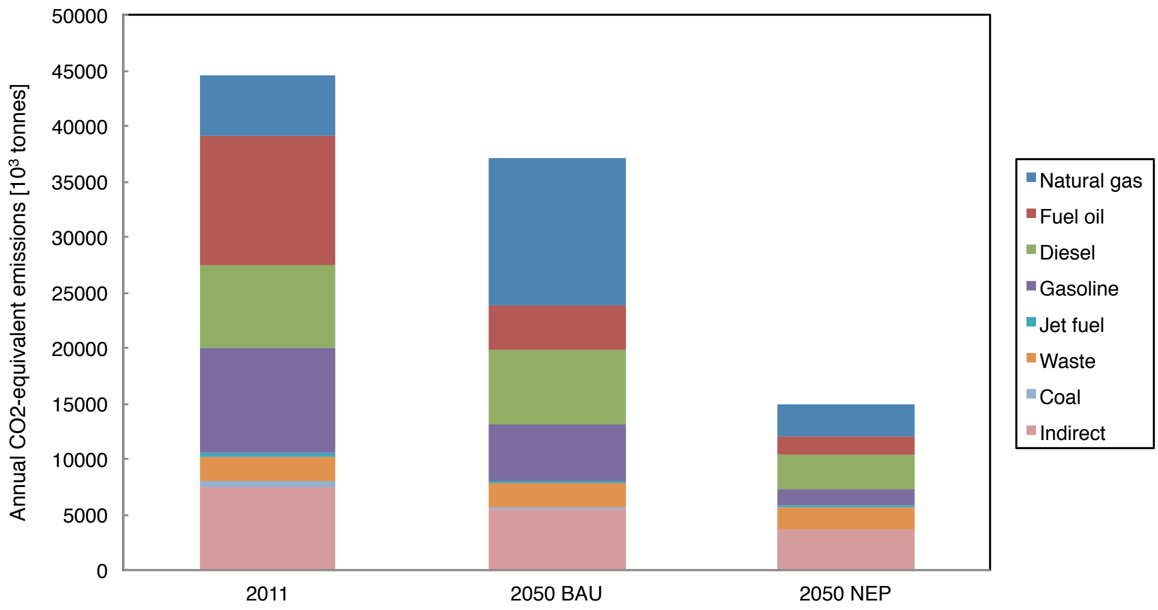

Figure 1.7 – Annual total CO_2 emissions for 2011 and the 2050CH Low(E) scenario.

"Elec. Nuclear", "Elec. Hydro", "Elec. Other renew", "Elec. Thermal", "Elec. Import", "Combined Heat&Power", "Boilers", "Other Heat" and "Transport(fuels)". In this case there is no differentiation between direct and indirect emissions. 'Combined Heat&Power" includes all the emissions related to generation of both electricity and heat. This avoids the problematic of emission allocation to heat or electricity production.

1.4.7 Exergy sub-model

Because of the inevitable uncertainties linked to future scenario approaches, only a simplified step approach of primary exergy to final exergy and to useful exergy is done in this paper. The embedded exergy of the energy system components is not yet considered. Nevertheless the three categories allow to identify the transformation steps in which there is margin to improve the exergy efficiency.

Table 1.12 shows the lower heating value (LHV) and the higher heating value (HHV) of the fuels together with their exergy value. Several approximations are made to simplify the approach. The exergy value for liquid fuels is assumed to be equivalent to their HHV [145]. On the other hand the exergy value of gaseous fuels varies [106]. The exergy value of solid fuels is calculated as the average between the LHV and the HHV. Note that more precise exergy values could be substituted but differences are not relevant when considering the various levels of other uncertainties in scenario based approaches. The basic idea for these simplifications is to give the opportunity for non-specialists to introduce new fuels in a simple way.

Table 1.11 – Fuel properties.

Fuel	**LHV** [MJ/kg]	**HHV** [MJ/kg]	**Exergy content** [MJ/kg]
Methane [106]	50.0	55.5	51.8
Hydrogen [106]	119.7	141.5	116.4
Gasoline [146]	43.4	46.5	46.5
Diesel [146]	42.8	45.8	45.8
Coal [146]	22.7	24.0	23.4
Wood (Hu. = 50%) [132]	8.55	10.3	9.42
Waste [132]	12.4	14.9	13.6

Useful exergy

The useful exergy represents the minimum amount of exergy required to deliver a given energy service. The useful exergy for the transportation sector is calculated as the exergy content of the consumed fuels times the average efficiency of the mean of transportation, and it represents the exergy needed to offset rolling friction and drag. The average efficiency of the internal combustion vehicles is 18% [147], considering stops and partial load. The useful exergy linked to the kerosene consumption in the aviation sector is estimated with an average exergy efficiency of 30% [148]. For estimating the useful exergy for the electric mobility, the electricity consumption is multiplied by an exergy efficiency of 69% for electric vehicles, value back-calculated from [149].

The entries having heat delivery as final energy service, like in the case of “industry (th.)”, “hot water (th.)”, “space heating (th.)”, “industry (el.)”, “heat pump (el.)” and “space heating (el.)”, have the useful exergy computed following Eq. 1.37.

$$\mathbf{Ex} = Q\big(1 - \frac{T_{\mathrm{amb}}}{T_{\mathrm{h}}}\big) \tag{1.37}$$

In Eq. 1.37, the exergy is equivalent to the product of the heat delivered times the Carnot factor, where T_{amb} is the ambient temperature and T_h is the temperature at which the heat is delivered. Table 1.12 and table 1.13 contain the service temperatures for the different heat uses and the ambient temperature for each month of the year, respectively.

Finally the useful exergy for the “Other (el.)” entry is judged to be equal to the electricity consumption, thus no conversion factor is required.

Table 1.12 – Temperatures considered for heat services in the exergy model.

Energy service	**Temperature** [K]
Process heating	473
Hot water	313
Space heating	293

Table 1.13 – Ambient temperature for each month of the year for the city of Bern, Switzerland [10].

Month	*Jan.*	*Feb.*	*Mar.*	*Apr.*	*May*	*Jun.*	*Jul.*	*Aug.*	*Sep.*	*Oct.*	*Nov.*	*Dec.*
Temperature [K]	271	273	277	283	285	290	293	290	286	282	278	272

Final exergy

Final exergy is defined as the exergy that the consumers buy or receive, which can be reduced to that of fuels, electricity and renewable heat from solar thermal panels and geothermal plants. Hence the entries representing electricity consumption, "el.", do not need any conversion factor, since the conversion from electricity consumed to final exergy is 1 to 1.

The final exergy associated to the fuels consumption in the transport sector is equal to the sum of the exergy content of all fuels consumed for mobility. A change from LHV basis to exergy content basis is performed using the values in Table 1.

The final exergies for "Industry (th.)", "Hot water (th.)" and "Space heating (th.)" are calculated in the same manner as for the fuels for mobility or consumed in boilers. On the other hand the final exergy for the heat from cogeneration systems is calculated as the exergy content of the "fuels-for-heat" consumption. "Fuels-for-heat" is defined as the heat supplied by the cogeneration system divided by 0.9 (0.1 being lost to atmosphere, since there are inevitable thermal losses in any cogeneration system). The calculation of "fuels-for-heat" answers to the problem of resources allocation between electricity and heat generation from cogeneration systems. "Fuels-for-heat" is equivalent to the fuel consumption if the heat from cogeneration was supplied by a boiler with 90% efficiency.

When it comes to renewable heat, the final exergy is estimated with Eq. 1.37 where Q is the heat obtained by the consumer and Th is the temperature at which the consumer receives the heat from the environment, which is 328 K [31] for thermal solar panels and 393 K for geothermal heat [150].

Table 1.14 – Conversion factors from primary exergy to renewable heat.

Technology	**Factor** [-]
Geothermal [2]	0.33
Solar thermal [3]	0.48

Primary exergy

The primary exergy is equivalent to the exergy obtained from the environment. The primary exergy of the fuels consumed in vehicles, boilers and cogeneration system ("fuels-for-heat") is obtained considering 10% losses in the extraction/production processes of the fuels, which is equivalent to say that the primary exergy for the fuels is equal to the final exergy divided by 0.9.

The primary exergy of the renewable heat is obtained from the values of renewable energy consumption, which are converted into primary exergy using the conversion factors in table 1.14. The values in table 1.14 are calculated for an ambient temperature (T_{amb}) of 282 K, as they are dependent to the ambient temperature they vary along the year.

In order to calculate the primary exergy of the entries representing electricity consumption (from "Transport (el.)" to "Other (el.)" it is necessary to know the specific primary exergy content of the electricity mix in Switzerland, which is computed as the sum of all primary exergy dedicated to electricity supply divided by the amount of electricity generated. The calculation is done on a monthly basis.

The primary exergy consumption of the technologies converting fossil or biogenic fuel is equivalent to the primary exergy of their fuel consumption subtracting the part corresponding to the "fuels-for-heat", to avoid double counting. Just as for the primary exergy calculation of the fuels for boilers, 10% losses in the extraction/production process of the fuels are assumed.

Table 1.15 contains the conversion factors for the evaluation of primary exergy use for electricity generation with renewable and nuclear technologies. Note that, as explained in [152], the conversion factor for nuclear should be much lower but a standard approach is used here.

The electricity mix in Switzerland also includes electricity imports depending on the energy scenario. In 2011, the main suppliers of electricity to Switzerland were Germany and France [155]. The electricity production mix of these two countries is taken into account to calculate the primary exergy content of the imported electricity. Table 1.16 contains this data and the corresponding primary exergy. The efficiencies in table 1.17 together with the data in table 1.12 are used for the calculation of the primary exergy. The imported electricity in Switzerland has a primary exergy content of 2.79 GWh/GWh$_{\mathrm{ImportedElec}}$. This value is calculated taking into account the net electricity

Table 1.15 – Conversion factors from primary to final exergy for renewable and nuclear electricity supply technologies.

Technology	**Factor** [-]
PV	0.17 [a]
Wind	0.44 [b]
Hydro dam	0.88 [107]
Hydro river	0.88 [107]
Geothermal	0.23 [c]
Nuclear	0.32 [152]

[a] Exergy efficiency is equal to the product of the Carnot factor (0.95, having T_{amb} = 282K and T_H = 5800K, corresponding to the temperature of the sun surface [151]), the PV panel efficiency (0.19 [153]) and the converter efficiency (0.94).

[b] Exergy efficiency is equal to the product of the recoverable energy of the intercepted wind kinetic energy (16/27, defined by the Betz formula [154]) and a factor taking into account the electro-mechanical losses of the turbine (0.75).

[c] Exergy efficiency of Húsavík plant (Kalina cycle) [150].

imports in Switzerland in 2011, which correspond to 25 TWh from France and 1.4 TWh from Austria [155]. The primary exergy content for the French and Austrian electricity mixes are 2.85 GWh/GWh_{Elec} and 1.61 GWh/GWh_{Elec}, respectively. The primary exergy contents are computed using the French and Austrian electricity mix in 2011 [11]. This value is calculated in an annual basis, and it must be considered as a strong assumption, since it is not possible to know neither the electricity mix of the neighbouring countries of Switzerland in the future, or the size of the electricity imports from each country.

1.5 Implementation to the Swiss energy scenarios for 2050

Besides having developed a model for a user-friendly tool, the author's model offers enough level of scientific rigour to reproduce the energy scenarios designed by the SFOE. However the results for some indicators may differ from those presented in the report describing the three scenarios for the Swiss energy transition [12], due to methodological differences, which are described in table 1.18. We consider the methodological differences to be an added value, as it has been discussed in the previous sections. Furthermore, the model offers the deposited waste indicator and the exergy indicator which are not available in the mentioned report [12].

This section analyses the results output by the model for the year 2011 and to the Business as Usual (BAU) and New Energy Policies (NEP) scenarios for 2050.

Figure 1.8 displays the performance of the year 2011 and the two scenarios for five indicators. The exergy indicator is not included since it is made of three sub-indicators: primary exergy, final exergy and useful exergy. Figure 1.9 is dedicated to that indicator.

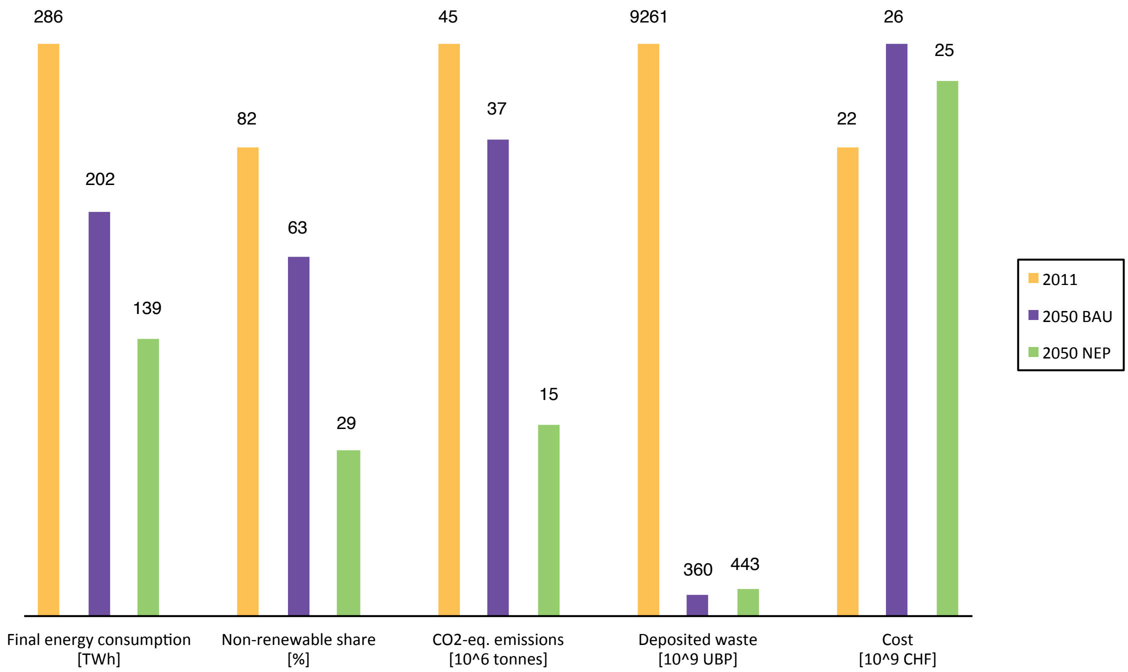

Figure 1.8 – Annual final energy consumption, non-renewable share, CO_2-equivalent emissions, deposited wast and cost of the energy system for 2011, new energy policies (NEP) scenario and business as usual (BAU) scenario.

Table 1.16 – Electricity production and primary exergy consumption for power generation in 3 neighbouring countries in 2011 [11].

Technology	**Elec. production** [TWh]			**Primary exergy** [TWh]		
	Italy	Germany	France	Italy	Germany	France
Coal	50	272	17	133	720	46
Oil	20	7	3	47	17	8
Gas	145	87	27	245	148	45
Biofuels	9	33	3	26	99	9
Waste	5	11	4	15	38	14
Nuclear	0	108	442	0	337	1382
Hydro	48	24	50	54	27	57
Geothermal	6	0	0	25	0	0
Wind	11	20	2	64	115	12
TOTAL	10	49	12	22	111	27
Exergy content, (TWh_{Ex}/TWh_{El})				2.09	2.64	2.85

Table 1.17 – First law efficiencies for the technologies for the technologies supplying the electricity imports.

Technology	**Efficiency** [%]
Coal	40
Oil	45
Gas	58
Biofuels	40
Waste	35

The BAU scenario is the most conservative scenario of the three scenarios proposed by the SFOE [12]. By 2050, it has a 17% reduction on the CO2 emissions in comparison to 2011, which was achieved with 17% energy from renewable sources in its energy mix. On the other hand, the NEP is the most optimistic scenario. It reduces the CO_2 emissions by 67% compared to 2011 values, with 71% renewable penetration in its energy mix [156]. Hence the level of energy independence is higher in the NEP scenario in comparison to the BAU scenario and 2011. The strong drop in deposited waste observed between 2011 and the 2050 scenarios is due to the nuclear phase out. The value for deposited waste is higher for the NEP senario than for the BAU scenario because of the higher renewable energy installed capacity.

The economic cost is relatively unaffected by the chosen scenario. The relative difference in cost between the two scenarios is lower than 5%. The NEP scenario certainly leads to a rise in investments for new renewable energy sources and energy efficiency. But that rise is offset by a decrease in the amount paid to import fuels, hence a higher operation cost (see Figure 1.6). The BAU scenario has an opposite cost structure: low investment and high operation cost. When comparing the BAU

Table 1.18 – Methodological differences between the calculation of the key indicators in the Swiss-Energyscope model and in the report [12].

Technology	**Swiss-Energyscope model**	**Report** [12]
Final energy consumption	Waste heat from power generation is included.	No waste heat.
CO_2 emissions	Calculated following a LCA approach. $CO2_{eq.}$ emissions from the IPCC2007-GWP100y	Only CO_2 emissions from combustion are considered.
Cost	Total cost of the energy system.	Only levelised cost of electricity.

and NEP scenarios to the current situation (2011), there is an increase on the cost indicator. This increase is related mainly to the growing population, which should rise from around 8 million today to some 9 million in 2050. Looking at per-capita figures, however, the annual cost will be about the same as today: between 2,700 and 2,900 francs in 2050 versus 2,700 francs today.

Figure 1.9 presents the three types of exergy consumption together with the final energy consumption for the above listed years and scenarios. 2011 presents the highest primary exergy and final exergy consumption, followed by the BAU and NEP scenarios, respectively. This order is not respected for the useful exergy indicator. The change is explained by the fact that the useful exergy indicator represents the minimum exergy required for supplying the energy services, thus the inefficiency of the exergy conversion chain in not reflected. The indicator only regards the energy service demand. In this case, the BAU scenario presents the highest “Other (el.)” electricity demand which is translated 1 to 1 into useful exergy.

Including the waste energy from power plants in the final energy consumption approximates the final energy consumption values to the primary exergy consumption. In 2011, the difference between the two indicators is 7%. This difference can be attributed to the conversion factor from primary to final exergy for the hydro power plants (see table 1.15). Nonetheless, the difference increases when the scenarios integrate higher percentages of renewable resources, as in the NEP scenario.

The percentages below the columns in Figure 1.9 compare the final exergy, useful exergy and final energy consumption of each year and scenario with its respective primary exergy consumption. It depicts the exergy efficiency of the conversion chain. The percentage of primary exergy converted into useful exergy in the NEP scenario is lower than in the BAU scenario. The low factors for the renewable electricity sources in table 1.15, particularly for PV, explain the lower efficiency of the NEP scenario. The NEP scenario has an important share of photovoltaic electricity, while the BAU scenario promotes the Combined Cycle Gas Turbine (CCGT) (see Figure 1.10). Considering 60% first law efficiency for CCGT, its conversion factors from primary to final exergy is 0.59, which is 3 times higher than the one for PV (0.17).

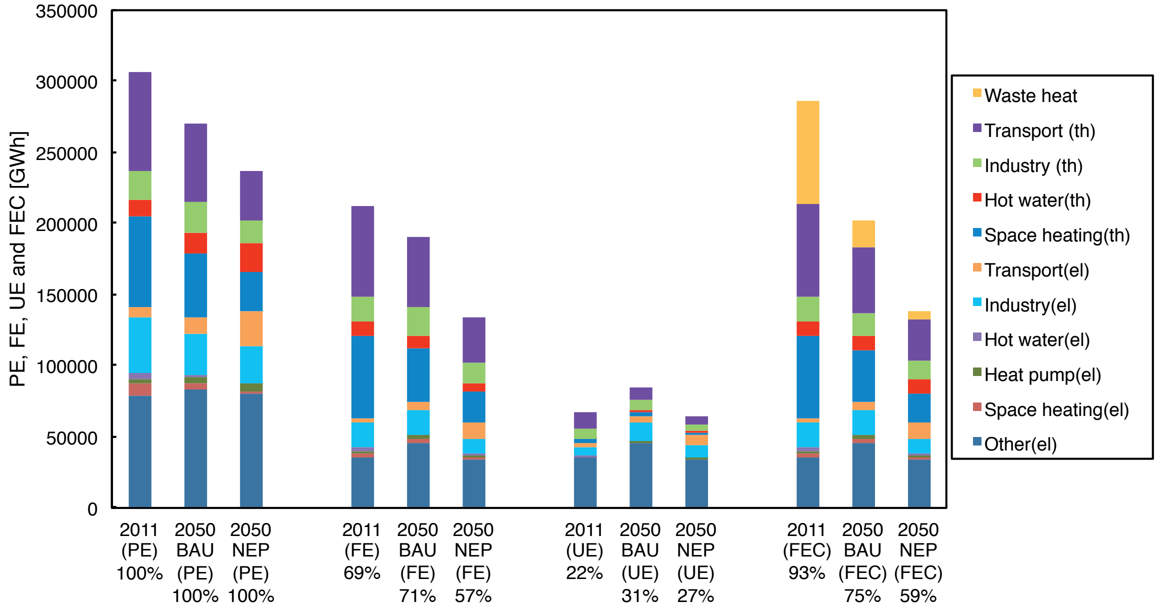

Figure 1.9 – Primary Exergy (PE), Final Exergy (FE), Useful Exergy (UE) and Final Energy Consumption (FEC) for 2011, Business as Usual scenario (BAU) in 2050, and New Energy Policies scenario (NEP) in 2050.

Figure 1.10 compares the primary exergy, final exergy useful exergy and final energy consumption by season (winter and summer) for the NEP scenario. The primary exergy consumption for “Other (el.)” is 20% higher in summer than in winter, while the final energy consumption for the same entry is constant along the year. The difference is due to the change in the electricity mix, which contains more electricity from PV in summer than in winter, hence there are more primary exergy apparent losses.

On the other hand, the conversion efficiency from primary exergy to useful exergy is better in summer (28%) than in winter (26%). The difference between the two of them is the lack of space heating in summer.

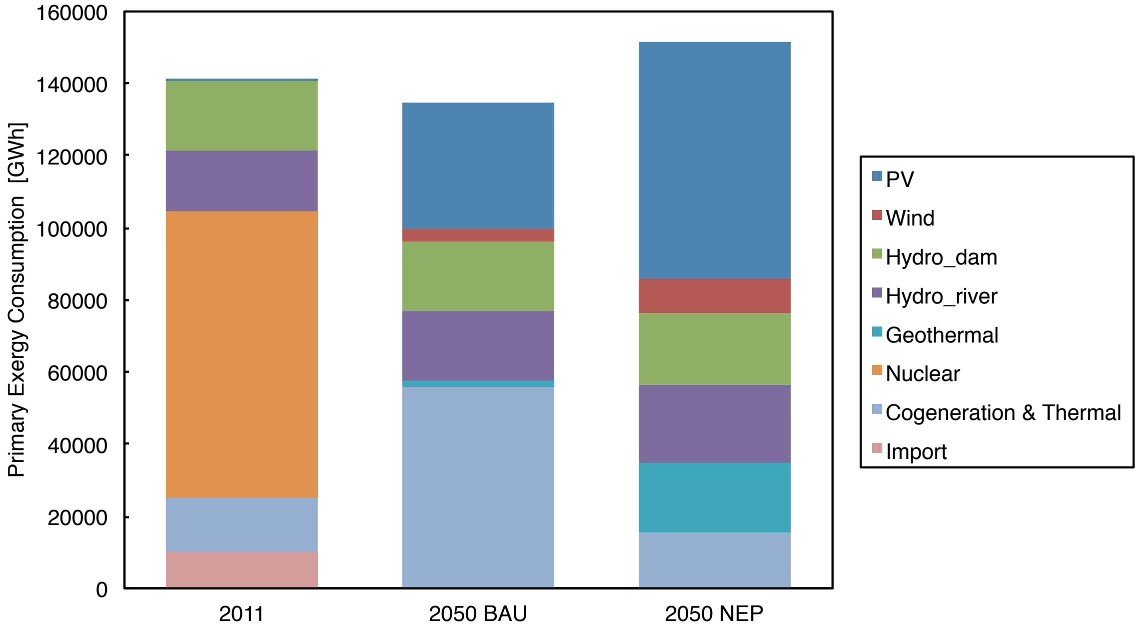

Figure 1.10 – Primary Exergy (PE) consumption for electricity supply in 2011, Business as Usual scenario (BAU) in 2050, and New Energy Policies scenario (NEP) in 2050.

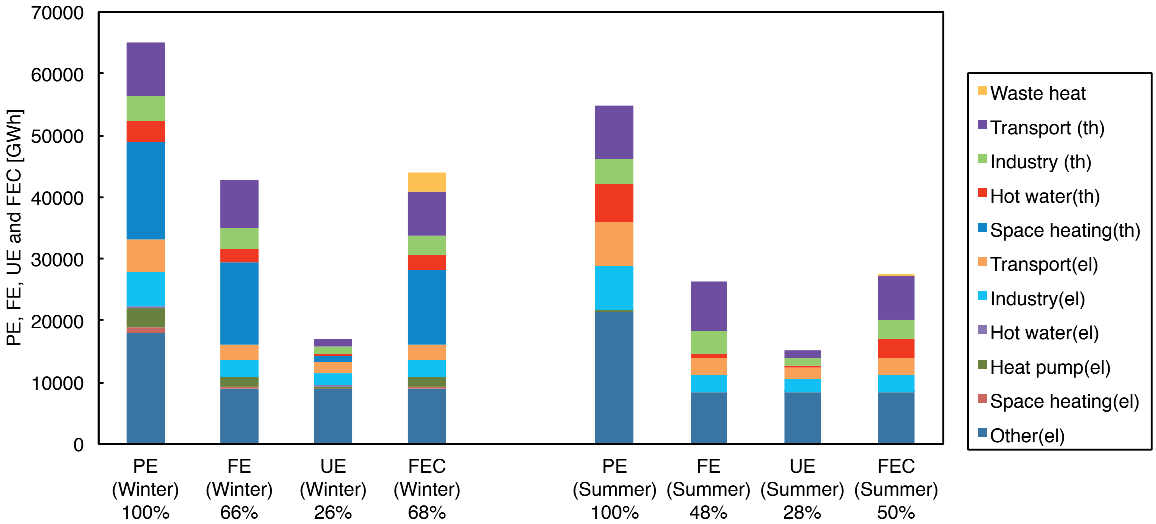

Figure 1.11 – Primary Exergy (PE), Final Exergy (FE), Useful Exergy (UE) and Final Energy Consumption (FEC) for the New Energy Policies scenario (NEP) in summer and winter 2050.

1.6 Conclusions

A new modelling framework for large-scale energy systems is developed in order to support decision-makers by improving their understanding of the energy system.

The Swiss-EnergyScope tool and its model can be classified in the simulation and snapshot categories, respectively. The development of a simulation tool allows users to evaluate the effect of a list of possible choices in terms of final energy consumption, total cost and environmental impact.

The choice of a snapshot model allows a clear access to monthly distributions, thus the concept of seasonal variation for supply and demand is made obvious. A sequential modelling approach is applied for the development of the model. This approach presents several advantages:

- A clear distinction between the demand and supply sides, highlighting the fact that actions can be taken in both sides, supply and demand.
- The easy integration of technologies affecting more than one of the three components of final energy consumption (electricity, heating and transportation) without the need of iteration loops.
- Highly responsive model (calculation time below 1 s).
- Highlighting the competition between electricity and fuels in heating and transportation.
- The possibility of emphasising the issues related to the seasonality of some resources.
- Leaving electricity as a free variable for helping to understand the necessity of balancing supply and demand, and highlighting the concept of seasonal variation.

The approach used for the development of the cost model provides an estimation which allows users to compare two energy scenarios in terms of economic cost. It also reduces the model complexity and calculation time since no installation/decommissioning pathway is computed. The cost sensitivity to assumptions is made obvious by the use of the “Cost” inputs.

The model structure and sub-models, along with the methodology for cost and environmental impact calculations, are described in detail in order to ensure reproducibility and adaptation to other energy systems.

The development of a new exergy indicator to assess scenarios of national energy transition provides a more coherent way to quantify the exergy efficiencies linked to each transformation steps from primary to final and useful exergies. The exergy indicator offers an overview of the energy system that no other indicator based on the first law of thermodynamics can provide, since it allows to quantify the energy “quality” of the energy vectors and energy services. For instance, the use of natural gas in a boiler for space heating at 40°C presents almost no efficiency penalty based on the first law. On the other hand, if the same case is evaluated from an exergetic point of view, the efficiency drops to 5%. The new indicator also highlights in which sector of use of energy progress can be made and allows to efficiently compare scenarios. It also provides a tool for policy makers to favour the best technology options with adequate policies.

Nevertheless further work is needed, in particular to see if the fact of adding the primary exergies of flux based renewables, like solar, to the primary exergies of stock based energies, like fuels, brings useful elements when comparing scenarios. The role of embedded exergies in the components of the energy system is also to be further studied.

2 Optimising biomass utilisation in large scale energy systems

2.1 State of the art

Biomass chemical conversion processes can produce solid, liquid or gaseous biofuels, which can substitute almost any kind of fossil fuel and the associated greenhouse gas emissions. Biomass is a scarce, diffused, low density resource and its use for energy can enter in competition with land use for food and fodder. Therefore it is necessary to make the best use of available biomass in order to maximize its CO_2 emissions abatement potential.

The CO_2 abatement potential of biomass is often assessed using a substitution approach [157], which consists in calculating the amount of fossil fuel being replaced by the use of biomass as energy source, and the associated reduction in CO_2. The substitution can be considered at the level of the fuel or at the level of the energy service. If the substitution is evaluated at the level of the fuel, the generated biofuel (e.g. ethanol or biodiesel) is assumed to replace its equivalent fossil equivalent [157]. Thus, in this approach the abatement potential depends only on the efficiency of the biomass conversion pathway, i.e. a higher efficiency will lead to a higher fossil fuel substitution.

When the substitution is rather considered at energy service level, the fossil conversion pathway is also accounted for. This implies that the environmental impact is also a function of the efficiency of the fossil pathway. The studies where the substitution is evaluated at energy service level consider several biomass and fossil pathways [158] [159] [160]. In comparison to the substitution at fuel level, this broadens the scope of the analysis allowing to find substitution combinations that maximize the CO_2 abatement potential. An example of this methodology is given in Steubing et al. [160]. Their work assessed the optimal use of woody biomass, agriculture residues, manure, sludge and bio-waste for Europe (EU-27) in 2010 and 2030 by assuming that biomass is used to provide energy services that otherwise would be supplied by fossil energy sources. The model includes 13 fossil technologies for supplying mobility, electricity and heat, together with 173 pathways for biomass.

However, this approach has shortcomings, which are common to [158] [157] [159]:

- The seasonal component of the energy demand and supply is not considered. That is a key shortcoming, since biomass has the potential to play an important role on the balancing of electricity supply and demand. Biomass CHP plants present a complementary seasonal profile to PV electricity, since they will produce heat and electricity during winter, when PV electricity production is low. Biomass can also be converted to other energy vectors like SNG, which can replace fossil fuels in balancing facilities like GTs. Furthermore, H_2 produced with excess electricity can be mixed with biogenic carbon from biomass to produce synthetic fuels [161].
- Besides having 2030 as one of the assessment years, the biomass pathways do not include the use of HPs and private electric mobility, technologies that are expected to have an important role in the European energy transition [143].
- It cannot analyse the effect of the biomass conversion pathway on the complete energy system.

To overcome these limitations, our work contextualizes the evaluation of biomass conversion pathways in a national energy system. This approach, which has gained increasing interest in recent years [162] [163] [164], allows obtaining a bigger picture of the synergies between the biomass conversion pathways and the energy system, e.g. linking the production of biofuels to the deployment of efficient end-use energy conversion technologies (e.g. HPs and battery electric vehicles).

In large scale energy systems (from cities to group of countries), Gerber et al. [162] modeled the integration of currently available woody biomass conversion technologies (dryers, boilers, gasifiers) in an urban system through multi-objective optimisation (MOO) taking into account total yearly cost and environmental impacts as performance indicators. The year is broken down into a set of independent time periods to capture the seasonal variability of certain supply and demand technologies.

Moret et al. [163] studied the synergies between geothermal energy and woody biomass in urban energy systems. They use a Mixed-Integer Linear Programming (MILP) model of the complete urban energy system for the analysis. In order to capture seasonality on both the supply and the demand sides, the year is split into four different periods with the possibility of seasonal storage. For woody biomass conversion, besides direct combustion and cogeneration, conversion to biofuels by a set of alternative processes (pyrolysis, Fischer-Tropsch synthesis and synthetic natural gas production) is studied.

Menten et al. [164] presented a methodology for the environmental evaluation of actions in the energy sector. A model for the French energy system based on the TIMES modelling framework is used to study the impact of biofuels in terms of Global warming potential (GWP). The model designs future energy scenarios through an optimisation problem having the net present value of total cost as objective. The production of biofuels is analysed under two scenarios. A first scenario with almost no CO_2 emissions restrictions and no threshold for the implementation of renewable energy sources, whereas the second scenario establishes measures to increase energy efficiency and the share of renewable sources in the energy mix, together with the implementation of a carbon tax.

In addition to its CO_2 emissions abatement potential, biomass can be used for seasonal electricity storage. The yields of the Fisher-Tropsh (FT) [165] and gasification-methanation [6] technologies are increased when H_2 is injected during the fuel synthesis step. If the hydrogen is produced from excess electricity, the biomass chemical conversion process becomes an electricity storage technology classified as either power-to-liquid (P2L) or power-to-gas (P2G), respectively. Power-to-liquid (P2L) and P2G technologies obtain the carbon molecule for fuel production from captured CO_2 [166]. When Fischer-Tropsch (FT) and gasification-methanation are used as P2L and P2G, biomass is the carbon source, hence the CO_2 capture step is avoided, with the consequent gain in efficiency. This use of the biomass emphasises the importance of considering at least the seasonal time resolution when the use of biomass is evaluated with a large-scale energy system model.

To the best of our knowledge, no work in the literature assesses the systematic evaluation of biomass usage pathways in a model representing a complete national energy system. Furthermore, most of the reviewed works ([157] [158] [159] [160]) do not take into account all possible technology combinations for the pathways, such as the use of HPs or battery electric vehicles, which can considerably increase the CO_2 abatement potential of biomass thanks to their high energy efficiency.

2.2 Author's contribution, a summary

In this chapter we perform a first evaluation of the CO_2 abatement potential of woody biomass based on a substitution approach in section 2.3. The substitution takes place at energy service level. The CO_2 abatement potential is given by the difference between the CO_2 emissions of the fossil fuel combustion in the fossil pathway and the emissions of the biomass pathway.

A second evaluation is carried out using a novel methodology developed by the authors. The methodology analyses the effect of linking biomass conversion pathways to the deployment of efficient end-use technologies at national level. It uses a MILP model for large-scale energy systems for the evaluation of biomass conversion pathways. These pathways are implemented in the large-scale energy system model and analysed through the scenarios described in section 2.4.2. In section 2.5, we apply the methodology to the Swiss energy system in the year 2035 for evaluating a set of scenarios in terms of global warming potential (GWP) and total annual cost, with the final aim of informing policy making.

Results from section 2.3 and 2.4 show that pathways including electrolysers present greater performances in terms of CO_2 abatement potential in comparison to pathways without. Hence in section 2.6, we further explore the use of woody biomass chemical conversion technologies for electricity seasonal storage within the case of Switzerland. Finally in section 2.7, a model for the Swiss energy system based on the modelling framework presented in chapter 1 is used to identify energy scenarios drawing the role of woody biomass in the Swiss energy transition. We generate the scenarios through optimisation using an evolutionary algorithm. From the generated scenarios, we derive investment strategies to ensure that Switzerland will not need to import electricity in the future and that all Swiss electricity production will be consumed within Switzerland.

2.3 Woody biomass for energy services and CO_2 mitigation, a critical analysis

Bioenergy pathways can produce solid, liquid or gaseous biofuels, which can substitute fossil fuel in almost all applications and avoid their associated fossil CO_2 emissions. Biomass chemical conversion processes suffer from high conversion losses, hence the importance of energy efficiency optimisation. In order to measure the CO_2 mitigation potential of biomass, the complete conversion chain, from raw biomass to final energy service, has to be evaluated.

In this section the CO_2 performance of bioenergy pathways is assessed using substitution approach at energy service level. The production of chemicals or food products from biomass is not considered, although bio-products may have much higher mitigation impact than the energy use [167]. The CO_2 mitigation potential of bioenergy pathways in producing the following energy services are compared: space heating, electricity and mobility. Both mature technologies (e.g. biomass boiler) and the future technologies discussed in the appendix C that are expected to become mature by 2035 are considered. The list of bioenergy technologies considered together with their respective conversion efficiencies are listed in Table B.2. The conventional fossil-based technologies that are substituted by the bioenergy pathways are also listed in Table B.2.

In order to study the CO_2 emissions abatement potential of woody biomass, the different bioenergy pathways are evaluated in replacement to fossil fuels technologies. The abatement potential depends on the fossil pathway that is replaced. The CO_2 performance of the different bioenergy pathways are compared in order to identify those with highest CO_2 mitigation potential. The aim is to identify for which energy services and with which conversion technologies biomass should be used to maximise CO_2 emission reduction. The study is limited to woody biomass but it could be extended to any other type of biomass.

Carbon Capture and Storage (CCS) is included in the study, whereby CO_2 emissions originating from the combustion of fossil fuels or biofuels are captured and stored. When carbon capture and storage (CCS) is combined to a biomass conversion process it captures biogenic CO_2 emissions that are neutral in terms of Greenhouse Gas (GHG) emissions [168]. Biomass-based pathways combined with CO_2 capture therefore act as CO_2 sinks that correspond to net negative values of CO_2 emissions.

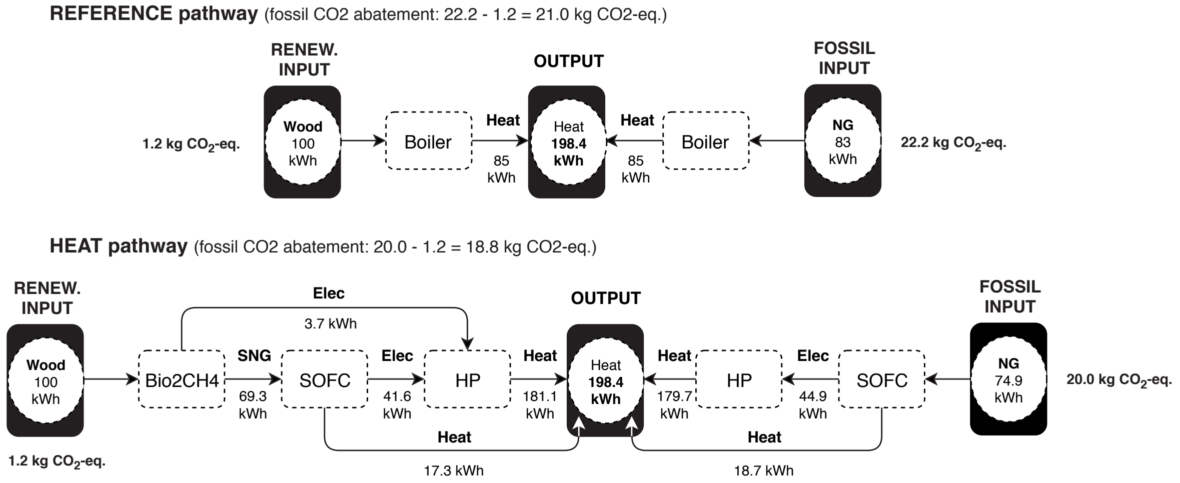

Figure 2.1 – Reference substitution pathway and substitution pathway example for the Heat approach.

Table 2.1 contains the emission factors for the substituted fossil fuels and the consumed wood. The emission factors are based on the "IPCC 2013 - Global Warming Potential GWP 100 years" impact assessment method. They include the emissions from the extraction, conditioning, distribution and combustion of the fuels. The electricity consumed by the electrolysers is assumed to be of photovoltaic origin, its impact factor is 76.8 kg_{CO_2}-eq./MWh_e (3 kW_e polycrystalline PV panels on flat roof in Switzerland [112]). The impact for the production and construction of the technologies in the conversion pathways have not been considered, since it represents a low fraction of the total impact. For example, the impacts for the production and installation of a wood and natural gas boilers are 28.9 kg_{CO_2}-eq/kW_{th} and 12.3 kg_{CO_2}-eq/kW_{th} [112], respectively. If they are added to the impact related to the fuels consumption, they only represent the 1.55% and 0.03% of the total value.

Table 2.1 – Impact associated to production, transport and combustion of the fuels, LHV reference.

Fuel	**Emission factor (GWP100a - IPCC2013)** [kg_{CO_2}-eq/MWh]
Natural gas	267 [132]
Hydrogen [a]	58.3
Wood [b]	11.8 [132]
Gasoline	345 [132]
Diesel	315 [132]
Heating oil	311 [132]
Coal	427 [112]

[a] Hydrogen produced through electrolysis with electricity from photovoltaic origin [158].
[b] LHV on a wet basis.

The biomass and fossil pathways are each represented by a series of conversion technologies to produce the energy service considered. For each energy service, a reference pathway, made of conventional technologies, serves the purpose of reference point for emission reduction potential. Figure 2.1 gives an example for a space heating both for the reference pathway using boiler (upper part of Figure 2.1) and a future pathway combining the use of advanced technologies (gasification, fuel cells and HPs) (lower part of Figure 2.1).

The CO_2 abatement potential is given by the difference between the CO_2 emissions of the fossil fuel combustion in the fossil pathway and the emissions of the woody biomass and photovoltaic electricity usage in the woody biomass pathway. The fossil fuel consumption of the fossil pathway is equal to the required amount to supply the same quantity of space heating as the woody biomass pathway (see Figure 2.1).

2.3.1 Biomass for space heating

This section analyses the fossil CO_2 abatement obtained when replacing a fossil-fueled technology by a woody biomass pathway to supply space heating only, or space heating and electricity (CHP).

The different pathways that deliver space heating are made of 1, 2 or 3 consecutive conversion technologies. The first one is the “Biomass to Fuel" technology, by which woody biomass is transformed into a gaseous or liquid biofuel, and possibly electricity as a by-product. The second technology “ Fuel to X " converts the biofuel into heat and/or electricity. It is worth noting that some technologies, such as the biomass integrated gasification combined cycle (BIGCC), combine both steps as they directly convert the woody biomass into electricity and/or heat. The third possible technology is HP which converts the electricity produced along the pathway (if any) into space heating. The fossil pathways which are substituted also integrate HPs if electricity production along the pathway, so that the comparison is fair. Figure 2.1 contains an example for such as “HEAT pathway".

Results are shown in Table 2.2. The fossil CO_2 emissions reduction obtained when 1 kWh of woody biomass is used for space heating in different bioenergy pathways as a substitution for NG pathways. Values in the same row represent the CO_2 abatement potentials of a given bioenergy pathway depending on the displaced NG pathways.

The values in Table 2.2 are normalised considering the emission reduction obtained if the biomass was used in a wood boiler that substitutes heat from a natural gas boiler (see reference pathway in Figure 2.1). A value of 1 in Table 2.2 corresponds to a reduction of 0.211 $kg_{CO_2}/kWh_{WoodyBiomass}$. The higher the values, the higher the CO_2 abatement potential of the biomass pathway. Negative values reflect situations where the biomass pathway actually generates more lifecycle CO_2 emissions than the fossil pathway that is substituted.

The results in Table 2.2 indicate that the mitigation potential depends greatly both on the biomass pathway considered and on the fossil pathway it substitutes. For instance, the first line in Table 2.2 shows that the CO_2 mitigation of a wood boiler ranges from 1, when the substituted technology is a natural gas boiler (reference pathway), to -0.01, if the substituted fossil pathway is a HP driven by electricity produced by a CCGT with carbon capture and storage CCS.

The worst case scenario (negative values of -0.49 in Table 2.2) corresponds to the following case: A "gasificaiton & methanation with electrolyser (Bio2CH4el) - Boiler" biomass pathway substitutes a HP driven by electricity that is generated by a CCGT plant with CCS (see Figure 2.2). The biomass pathway produces 12.3 kg CO_2-eq. (on a life cycle basis), while the emissions from the fossil pathway are only 2.0 kg CO_2-eq, thanks to the use of a HP and because the CO_2 emitted by the CCGT plant is captured and sequestrated.

The biomass pathway offering the highest emission reduction potential is the "Bio2CH4el - hybrid cycle solid oxide fuel cell and gas turbine (SOFC-GT) with CCS - HP" pathway, which could lead to 8.48 times the emissions savings of the reference pathway (only biomass boiler). In this pathway, the Bio2CH4el system produces bio-SNG from woody biomass and hydrogen produced from renewable electricity. The bio-SNG is then used in an solid oxide fuel cell (SOFC) with bottoming GT, combined with CCS and where the electricity produced by the fuel cell is used to drive a HP. Given the CO_2 sequestrated by the CCS is of biogenic origin, the system acts as a carbon sink, removing CO_2 from the atmosphere.

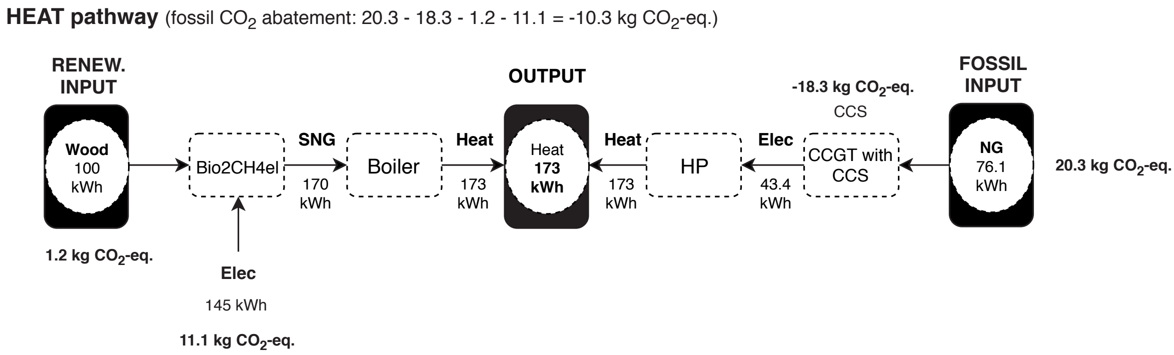

Figure 2.2 – Substitution pathway with the minimum CO_2 abatement potential (-0.49).

2.3.2 Biomass for space heating and electricity production

The pathways that deliver heat and electricity are composed of two technologies: "Biomass to Fuel" and "Fuel to X". Figure 2.3 contains an example for such "HEAT & ELECTRICITY" pathway.

Results are shown in Table 2.3 which gives the CO_2 emissions reduction obtained when 1 kWh of woody biomass is used for supplying space heating and electricity, in replacement for fossil pathways offering the same energy services. The reference value for normalisation is the same as in Table 2.2

Table 2.2 – Normalised fossil CO_2 emissions reduction through the substitution of natural gas pathways by biomass pathways for space heating (Reference value: $1.00 \equiv 0.211\ \mathrm{kg}_{CO_2}/\mathrm{kWh}_{WoodyBiomass}$). Table cells coloured in shades of green correspond to solutions that have a better mitigation effect than the use of biomass in a boiler, while cells coloured in shades of red represent solutions where the mitigation effect is lower.

			Heat (Natural gas)					
Biomass to Fuel	Fuel to X	Elec. to Heat	Boiler	CHP engine	SOFC	SOFC-GT	CCGT	CCGT with CCS
–	Boiler	–	1.00	0.43	0.35	0.26	0.37	-0.01
HTG	Boiler	–	1.02	0.44	0.36	0.27	0.38	-0.01
gasificaiton & methanation (Bio2CH4)	Boiler	–	1.01	0.43	0.35	0.27	0.37	-0.01
Bio2CH4el	Boiler	–	1.57	0.41	0.25	0.07	0.29	-0.49
FT	Boiler	–	0.48	0.19	0.15	0.10	0.16	-0.04
Fischer-Tropsch with electrolyser (FTel)	Boiler	–	0.79	0.23	0.15	0.06	0.17	-0.21
HTG	CHP engine	HP	1.99	0.88	0.73	0.56	0.77	0.04
Bio2CH4	CHP engine	HP	2.04	0.91	0.75	0.58	0.79	0.04
Bio2CH4el	CHP engine	HP	4.11	1.57	1.22	0.84	1.32	-0.37
FT	CHP engine	HP	1.01	0.43	0.35	0.26	0.37	-0.01
FTel	CHP engine	HP	1.83	0.70	0.55	0.38	0.59	-0.16
HTG	SOFC	HP	2.33	1.04	0.86	0.67	0.91	0.05
Bio2CH4	SOFC	HP	2.41	1.08	0.89	0.69	0.94	0.05
Bio2CH4el	SOFC	HP	5.01	1.99	1.57	1.12	1.68	-0.33
HTG	SOFC-GT	HP	2.91	1.30	1.08	0.84	1.14	0.08
Bio2CH4	SOFC-GT	HP	3.02	1.36	1.13	0.88	1.19	0.08
Bio2CH4el	SOFC-GT	HP	6.51	2.68	2.15	1.57	2.29	-0.27
HTG	SOFC-GT with CCS	HP	3.66	2.10	1.88	1.65	1.94	0.90
Bio2CH4	SOFC-GT with CCS	HP	3.82	2.20	1.98	1.73	2.04	0.96
Bio2CH4el	SOFC-GT with CCS	HP	8.48	4.75	4.23	3.67	4.37	1.88
HTG	CCGT	HP	2.23	0.99	0.82	0.64	0.87	0.05
Bio2CH4	CCGT	HP	2.30	1.03	0.85	0.66	0.90	0.05
Bio2CH4el	CCGT	HP	4.74	1.86	1.47	1.03	1.57	-0.34
HTG	CCGT with CCS	HP	2.77	1.65	1.49	1.32	1.53	0.78
Bio2CH4	CCGT with CCS	HP	2.88	1.72	1.56	1.39	1.60	0.83
Bio2CH4el	CCGT with CCS	HP	6.17	3.57	3.21	2.82	3.31	1.57
BIGCC		HP	2.14	0.95	0.79	0.61	0.83	0.04
integrated gasifier with fuel cell and gas turbine (Gas-FC-GT)		HP	3.47	1.57	1.30	1.02	1.37	0.10
Gas-FC-GT with CCS		HP	4.89	3.08	2.83	2.56	2.90	1.70
Torrefaction	Supercritical plant	HP	2.02	0.90	0.74	0.58	0.79	0.04

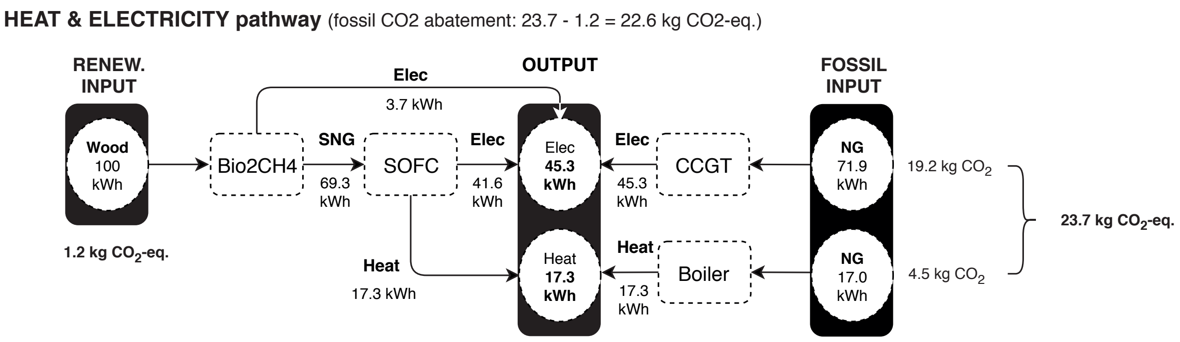

Figure 2.3 – Substitution pathway example for the Heat & Electricity approach.

($0.211\ \mathrm{kg}_{CO_2}/\mathrm{kWh}_{WoodyBiomass}$).

The woody biomass pathway in the first row of Table 2.3 is composed by only a boiler for heat-only production, and serves as a reference pathway. Its abatement potential is thus constant along the row, as the different fossil-based electricity supply technologies are not used, since the woody biomass pathway only supplies space heating.

The highest CO_2 abatement potentials are obtained when supercritical coal power plants for electricity generation are substituded, due to the low efficiency of the coal technology and the high emission factor of coal in comparison to the natural gas based CCGT technology (see Tables 2.1 and B.2). Actually the combination of CCGT with CCS technologies is the most efficient fossil pathway and thus presents the lowest abatement potential for biomass pathways (Table 2.3). The worst case is obtained when the “Bio2CH4el → CCGT" pathway replaces the “CCGT with CCS + Boiler(Natural gas)" fossil pathway. In this case the fossil CO_2 abatement is even negative (-0.34), which reflects the fact that the fossil pathway emits less fossil CO_2 on a life cycle basis than the woody biomass pathway thanks to the use of the CCS technology.

As for space heating only (Table 2.2), the highest abatement potential (7.87) is given by the biomass pathway in which the Bio2CH4el and SOFC-GT with CCS technologies are combined together (Table 2.3). In addition, comparing the results in these two tables indicates that substituting fossil fuels for space heating brings slightly higher mitigation impact than displacing fossil electricity.

2.3.3 Biomass for space heating and mobility

If biomass is converted into a fuel it can be used to substitute the corresponding conventional fossil fuel used in transportation. When considering a 2035 horizon, it is however critical to consider both the possible fuel substitution but also the expected fuel efficiency increase of vehicles. It is in particular necessary to take into account the full electrification and hybridisation of power trains. Table B.2 defines the efficiencies of different power trains in cars that are used in this study.

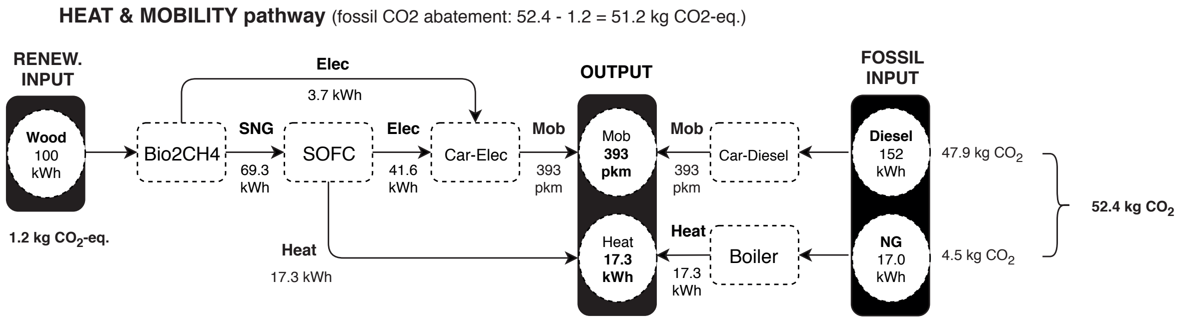

Figure 2.4 – Substitution pathway example for the Heat & Mobility approach.

The pathway transforming the energy content of woody biomass into mobility service can be formed by up to three technologies: “Biomlass to Fuel", “Fuel to X" and “Elec. to Transport". “Biomass to Fuel" and “Fuel to X" play the same role as in the pathways analysed above for space heating and electricity production (Tables 2.2 and 2.3), with the added possibility for “Fuel to X" to be a private

Table 2.3 – Fossil CO_2 emissions reduction through the substitution of fossil fuels by biomass usage pathways for space heating and electricity supply (Reference value: $1.00 \equiv 0.211$ $kg_{CO_2}/kWh_{WoodyBiomass}$). Table cells coloured in shades of green correspond to solutions that have a better mitigation effect than the use of biomass in a boiler, while cells coloured in shades of red represent solutions where the mitigation effect is lower.

		Electricity & Heat			
Biomass to Fuel	**Fuel to X**	**CCGT Boiler(Natural gas)**	**CCGT with CCS Boiler(Natural gas)**	**Supercritical(Coal) Boiler(Natural gas)**	**Supercritical(Coal) with CCS Boiler(Natural gas)**
–	Boiler	1.00	1.00	1.00	1.00
HTG	Boiler	0.87	0.78	0.99	0.79
Bio2CH4	Boiler	0.90	0.83	0.99	0.84
Bio2CH4el	Boiler	1.57	1.57	1.57	1.57
FT	Boiler	0.48	0.48	0.48	0.48
FTel	Boiler	0.79	0.79	0.79	0.79
HTG	CHP engine	0.99	0.39	1.83	0.49
Bio2CH4	CHP engine	1.03	0.42	1.88	0.52
Bio2CH4el	CHP engine	1.89	0.56	3.76	0.79
FT	CHP engine	0.51	0.21	0.93	0.26
FTel	CHP engine	0.86	0.27	1.68	0.37
HTG	SOFC	1.03	0.24	2.13	0.38
Bio2CH4	SOFC	1.07	0.26	2.20	0.40
Bio2CH4el	SOFC	2.00	0.17	4.54	0.49
HTG	SOFC-GT	1.22	0.20	2.64	0.38
Bio2CH4	SOFC-GT	1.27	0.21	2.75	0.40
Bio2CH4el	SOFC-GT	2.49	0.06	5.88	0.48
HTG	SOFC-GT with CCS	2.01	1.02	3.40	1.19
Bio2CH4	SOFC-GT with CCS	2.12	1.09	3.55	1.27
Bio2CH4el	SOFC-GT with CCS	4.57	2.20	7.87	2.61
HTG	CCGT	0.87	0.05	2.01	0.19
Bio2CH4	CCGT	0.90	0.05	2.08	0.20
Bio2CH4el	CCGT	1.57	-0.34	4.24	-0.01
HTG	CCGT with CCS	1.53	0.78	2.58	0.91
Bio2CH4	CCGT with CCS	1.60	0.83	2.68	0.96
Bio2CH4el	CCGT with CCS	3.31	1.57	5.72	1.87
BIGCC		1.20	0.62	1.99	0.72
Gas-FC-GT		1.37	0.10	3.14	0.32
Gas-FC-GT with CCS		2.90	1.70	4.57	1.90
Torrefaction	Supercritical plant	0.79	0.04	1.83	0.17

passenger vehicle. The "Elec. to Transport" technology is a battery electric car using all electricity production of the pathway for mobility.

Table 2.4 shows the fossil CO_2 emissions reduction obtained if the primary energy source for mobility and space heating is biomass instead of fossil fuels. The biomass pathways that produce heat are used to replace the use of natural gas boilers for space heating, see the "HEAT & MOBILITY" pathway example in Figure 2.4. As in the previous Tables 2.2 and 2.3, the reference value for normalisation is 0.211 $kg_{CO_2}/kWh_{WoodyBiomass}$.

The highest fossil CO_2 emissions reduction (9.55) is achieved when woody biomass is used in the "Bio2CH4el → SOFC-GT with CCS → Car-Elec" pathway to replace cars fueled by compressed natural gas (CNG) (see Figure 2.5). In this pathway, there is also a small amount of heat production (16 % thermal efficiency) from SOFC-GT with CCS, which substitutes natural gas boilers for space heating.

Table 2.4 – Fossil CO_2 emissions reduction through the substitution of natural gas by biomass usage pathways for space heating and mobility (Reference value: $1.00 \equiv 0.211\ \mathrm{kg}_{CO_2}/\mathrm{kWh}_{WoodyBiomass}$). Table cells coloured in shades of green correspond to solutions that have a better mitigation effect than the use of biomass in a boiler, while cells coloured in shades of red represent solutions where the mitigation effect is lower.

			Transport & Heat			
Biomass to Fuel	Fuel to X	Elec. to Transport	Car-Diesel Boiler(Natural gas)	Car-CNG Boiler(Natural gas)	Car-Elec(CCGT) Boiler(Natural gas)	Car-Elec(Supercritical coal) Boiler(Natural gas)
–	Boiler	–	1.00	1.00	1.00	1.00
HTG	Car-CNG	–	0.97	1.02	0.48	0.83
Bio2CH4	Car-CNG	–	0.96	1.01	0.43	0.81
Bio2CH4el	Car-CNG	–	1.45	1.57	0.17	1.10
FT	Car-Diesel	–	0.59	0.62	0.18	0.47
FTel	Car-Diesel	–	1.01	1.08	0.21	0.78
HTG	CHP engine	Car-Elec	2.15	2.26	0.99	1.83
Bio2CH4	CHP engine	Car-Elec	2.21	2.31	1.03	1.88
Bio2CH4 & Electrolysis	CHP engine	Car-Elec	4.47	4.71	1.89	3.76
FT	CHP engine	Car-Elec	1.09	1.15	0.51	0.93
FTel	CHP engine	Car-Elec	1.99	2.09	0.86	1.68
HTG	SOFC	Car-Elec	2.55	2.69	1.03	2.13
Bio2CH4	SOFC	Car-Elec	2.63	2.77	1.07	2.20
Bio2CH4el	SOFC	Car-Elec	5.51	5.84	2.00	4.54
HTG	SOFC-GT	Car-Elec	3.19	3.37	1.22	2.64
Bio2CH4	SOFC-GT	Car-Elec	3.31	3.50	1.27	2.75
Bio2CH4el	SOFC-GT	Car-Elec	7.18	7.61	2.49	5.88
HTG	SOFC-GT with CCS	Car-Elec	3.93	4.11	2.01	3.40
Bio2CH4	SOFC-GT with CCS	Car-Elec	4.11	4.29	2.12	3.55
Bio2CH4el	SOFC-GT with CCS	Car-Elec	9.13	9.55	4.57	7.87
HTG	CCGT	Car-Elec	2.45	2.60	0.87	2.01
Bio2CH4	CCGT	Car-Elec	2.53	2.68	0.90	2.08
Bio2CH4el	CCGT	Car-Elec	5.27	5.60	1.57	4.24
HTG	CCGT with CCS	Car-Elec	2.98	3.11	1.53	2.58
Bio2CH4	CCGT with CCS	Car-Elec	3.09	3.23	1.60	2.68
Bio2CH4el	CCGT with CCS	Car-Elec	6.65	6.95	3.31	5.72
BIGCC		Car-Elec	2.30	2.40	1.20	1.99
Gas-FC-GT		Car-Elec	3.82	4.04	1.37	3.14
Gas-FC-GT with CCS		Car-Elec	5.22	5.43	2.90	4.57
Torrefaction	Supercritical plant	Car-Elec	2.23	2.36	0.79	1.83

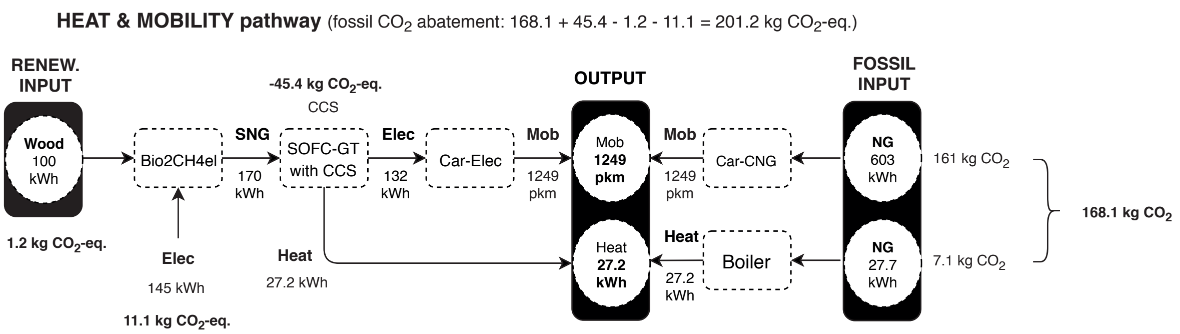

Figure 2.5 – Substitution pathway with the maximum CO_2 abatement potential (9.55).

Interestingly there is no negative values in Table 2.4, which indicates that all substitution pathways do bring CO_2 emissions reductions. The reason for this lies in the fact that battery electric vehicles are about 3 times more energy efficient than diesel cars (see Table B.2). Hence, using electric cars that run on renewable electricity instead of diesel cars will bring higher abatement potential than substituting fossil-based heaters of power plants by biomass-based technologies. Comparing the results from Tables 2.2, 2.3 and 2.4 shows that the “space heating and mobility" pathways offer the highest mitigation potentials.

The difference on efficiencies between fossil fuel cars and battery electric cars is such as that it brings a higher CO_2 mitigation to replace a diesel or CNG car by an electric car running on biomass electricity than a battery electric car running on electricity from supercritical coal power plant. A diesel car emits 0.122 kg CO2-eq./pkm, while a battery electric car using electricity generated from coal has an impact of 0.100 CO2-eq./pkm (based on emission factors and efficiencies reported in Tables 2.1 and B.2).

2.4 A mixed-integer linear programming (MILP) model to assess biomass pathways

2.4.1 Model description

The model used for this work is based on the MILP modelling framework presented in [169], which is based on the work in [92]. According to the classification proposed by [92], the model falls in the “snapshot” category. It evaluates the configuration of the energy system over a 1-year timespan, which is divided into 12 monthly timesteps. The timespan corresponds to the year 2035. It is assumed that the complete energy system is rebuilt in this year, with the efficiencies and cost parameters of 2035.

Figure 2.6 is a graphical representation of the modelling framework. It contains two main elements: units and layers. “Services Units” define the end-uses energy demand: passenger mobility requirement (“Mobility”), freight transport (“Freight”), heating demand for space heating and hot water (“Low T Heat”), heating demand for industrial processes (“High T Heat”) and electricity demand for usages not related to heating or mobility (“Electricity”), such as lighting. The “Mobility Units”, “Freight Units”, “Low T Heat Units”, “High T Heat Units” and “Electricity Supply” are the energy conversion units available, while the “Resources Units” represent their inputs.

“Wood Conversion Units” is a group of units representing the chemical conversion of wood into different types of biofuels. These units are not present in the original modelling framework described in [92] and are added for the purpose of this study.

Layers correspond to the end-uses energy demand and resources balances in the system. For example, the “Mobility” and “Private Mobility” layers ensure that all the private mobility provided by battery electric vehicles has to be consumed by the “Mobility” demand unit.

The decision variables of the model are the $\mathbf{Mult_t}(j,t)$, which represent the average demand or supply

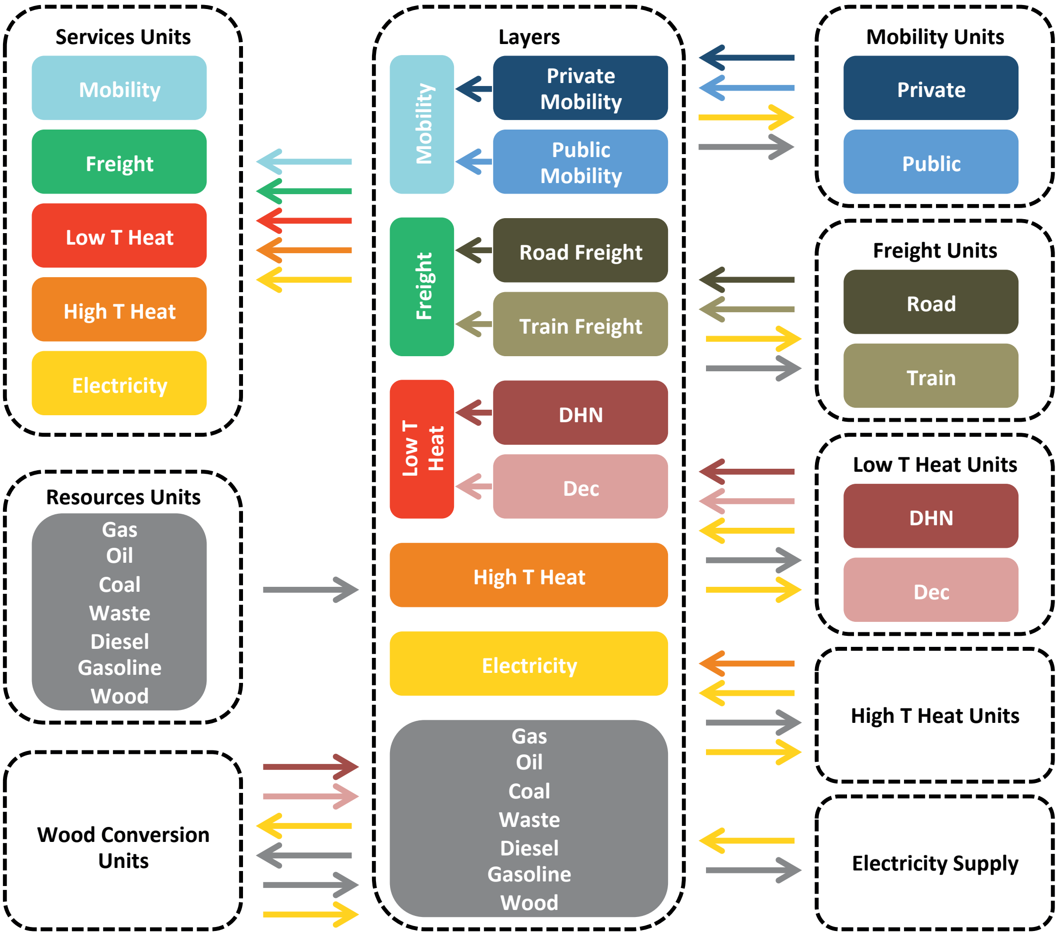

Figure 2.6 – Graphical representation of the modelling framework

power for each unit j in time step t[1]. Moret et al. [169] provide a detailed description of all the sets, parameters, variables and constraints of the MILP model. The model offers two output indicators: the Annual Total Cost of the energy system ($\mathbf{C_{tot}}$) and the Annual Global Warming Potential Impact Factor ($\mathbf{GWP_{tot}}$). Eq. 3.41 - 2.4 list the main constraints of the MILP formulation, associated to the calculation of $\mathrm{GWP_{tot}}$ (chosen as the objective in the optimisation). Eq. 2.5 - 2.9 are used to calculate $\mathbf{C_{tot}}$. Thus only one criterion objective ($\mathbf{GWP_{tot}}$) is taken into account in the optimisation, and no constraint is put on the annual total cost value. However, we ensure that the size of the technologies (and so the investment cost) is realistic by considering a GWP impact for the construction of the technologies ($\mathrm{gwp_{const}}$).

$$\min\ \mathbf{GWP_{tot}} = \sum_{j\in Units} \mathbf{GWP_{const}}(j) + \sum_{i\in Resources} \mathbf{GWP_{op}}(i) \tag{2.1}$$

$$\text{s.t. } \mathbf{Mult}(j) \geq \mathbf{Mult_t}(j,t) \qquad \forall j \in Units, \forall t \in T \tag{2.2}$$

$$\mathbf{GWP_{const}}(j) = gwp_{\mathrm{const}}(j)\mathbf{Mult}(j) \qquad \forall j \in Units \tag{2.3}$$

$$\mathbf{GWP_{op}}(i) = \sum_{t\in T} gwp_{\mathrm{op}}(i)\mathbf{Mult_t}(i,t)\,t_{\mathrm{op}}(t) \qquad \forall i \in Resources \tag{2.4}$$

$$\mathbf{C_{tot}} = \sum_{j\in Units} (\tau(j)\mathbf{C_{inv}}(j) + \mathbf{C_{maint}}(j)) + \sum_{j\in Resources} \mathbf{C_{op}}(i) \tag{2.5}$$

$$\tau(j) = \frac{i(i+1)^{\mathrm{n(j)}}}{(i+1)^{\mathrm{n(j)}} - 1} \qquad \forall j \in Units \tag{2.6}$$

$$\mathbf{C_{inv}}(j) = c_{\mathrm{inv}}(j)\mathbf{Mult}(j) \qquad \forall j \in Units \tag{2.7}$$

$$\mathbf{C_{maint}}(j) = c_{\mathrm{maint}}(j)\mathbf{Mult}(j) \qquad \forall j \in Units \tag{2.8}$$

$$\mathbf{C_{op}}(i) = \sum_{t\in T} c_{\mathrm{op}}(i,t)\mathbf{Mult_t}(i,t)\,t_{\mathrm{op}}(t) \qquad \forall i \in Resources, \forall t \in T \tag{2.9}$$

The Units set includes all the units of the system except “Services Units” and “Resources Units”. The Resources set contains all the “Resources Units”.

The Annual Total Cost ($\mathbf{C_{tot}}$) is calculated as shown in Eq. 2.5, where $\mathbf{C_{inv}}$(j) and $\mathbf{C_{maint}}$(j) are the annualized investment and the annual maintenance cost for unit j, respectively. $\mathbf{C_{op}}$(i) is the cost for resource i. The Annual Global Warming Potential Impact Factor ($\mathbf{GWP_{tot}}$) is calculated in Eq. 2.1, where $\mathbf{GWP_{const}}$(j) is the annual impact of construction and decommissioning of unit i, and $\mathbf{GWP_{op}}$(i) is the impact of the consumption of resource i.

Table 2.5 contains the description of the parameters in the equations and Table 2.6 displays the

[1] The demand and supply are all represented in GW apart from Mobility Units and Freight Units which are represented in passenger-kilometer (pkm) and ton-kilometer (tkm), respectively.

gwp_{op} for the "Resources Units". The gwp_{const} and gwp_{op} parameters are based on the "IPCC 2013 GWP 100 years".

Table 2.5 – Parameters used in Eq. 2.1 - 2.9, together with their units and description.

Parameter	Unit	Description
n(j)	[year]	Life time
c_{inv}(j)	[10^6 CHF/GW]	Specific investment cost
c_{maint}(j)	[10^6 CHF/GW]	Annual specific maintenance cost
c_{op}(i,t)	[10^6 CHF/GW]	Resource price
t_{op}(j)	[hour]	Time-step duration
gwp_{const}(j)	[10^3 $t_{CO_2\text{-eq.}}$/GW/year]	Annual specific impact of construction and decommissioning
gwp_{op}(i)	[10^3 $t_{CO_2\text{-eq.}}$/GWh]	Operation impact from combustion, production and transport for resources

Table 2.6 – Operation impact from combustion, production and transport for "Resources Units".

Resource	$\mathbf{gwp_{op}}$ [10^3 $t_{CO_2\text{-eq.}}$/GWh] [163]
NG	0.267
Oil	0.311
Coal	0.418
Waste	0.150
Gasoline	0.345
Diesel	0.315
Wood	0.012

2.4.2 Definition of the scenarios integrating the woody biomass pathways

Figure 2.7 illustrates the methodology. The scenarios evaluate different usage pathways for 5000 GWh of wood (LHV based, with 50% humidity[2]). Each one of the scenario assesses a different conversion pathway for this quantity of wood in the Swiss national energy system in the year 2035, modeled with the MILP formulation introduced in section 2.4.1. The conversion pathways are defined by a set of constraints specific to each scenario. The scenario results are calculated by solving the MILP problem. The objective function is the minimization of $\mathbf{GWP_{tot}}$. Additionally, the total annual cost of the system ($\mathbf{C_{tot}}$) is calculated.

This methodology is implemented in the OSMOSE energy modelling platform [170]. The mathematical programming problem is defined using AMPL [171] and it is solved with CPLEX 12.6.1.0.

[2] Humidity is defined as the mass of water in 1 kg of wet wood.

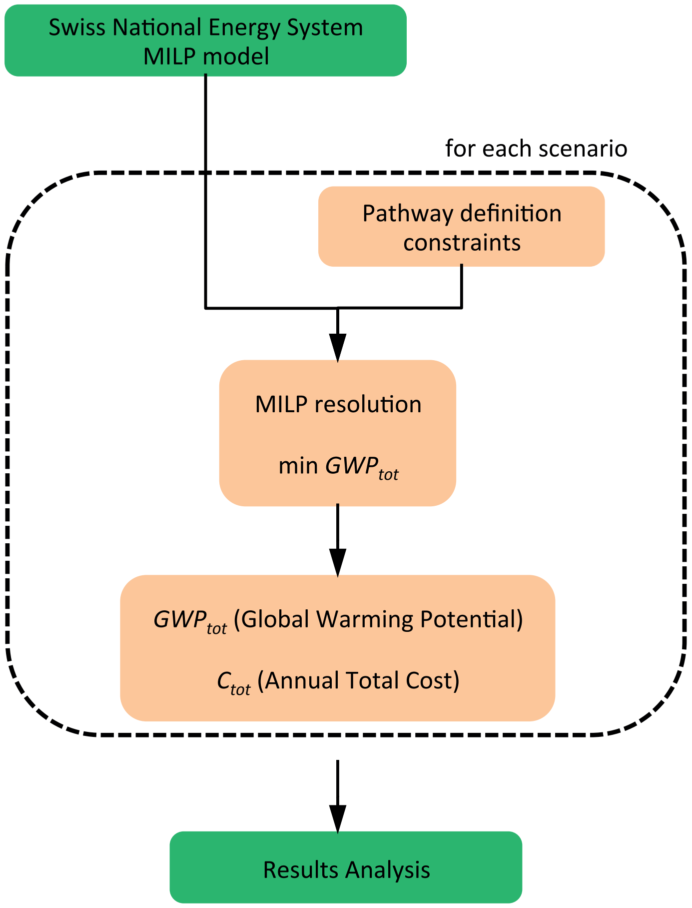

Figure 2.7 – Scenario evaluation methodology.

A wood usage pathway implies the sequential use of up to three conversion units/technologies. Each one of the units belongs to a different "pathway construction group". The pathway construction groups are:

- "Chemical Conversion", transforming wood into gaseous or liquid fuel (synthetic natural gas, oil or diesel).
- "Technology 1", converting wood or fuel from the chemical conversion step into mobility services, electricity and/or heat.
- "Technology 2", supplying heat or mobility services from electricity generated by Technology 1 group.

Table 2.7 lists the technologies included in each group. As an example, a pathway can be "Bio2CH4-Ind CHP-HP". This pathway includes three units, one from each group. Another possibility could be "SNG". This pathway only considers a chemical conversion unit. Figure 2.8 shows the graphical representation of the two pathways compared with the reference pathway.

Table 2.7 – Lists of units included in each pathways construction group.

Chemical conversion	**Technology 1**	**Technology 2**
Bio2CH4	Ind CHP	HP
Bio2CH4el	district heating network (DHN) CHP	BEV
FT	decentralised (Dec) CHP	
FTel	advanced (Adv) CHP	
fast pyrolysis (Pyro)	compressed natural gas (CNG) Car)	
fast pyrolysis with upgrading (PyroUp)	thermal heat pump (ThHP)	
	BIGCC	
	externally-fired gas turbine (MGT)	
	Gas-FC-GT	

Bio2CH4 [6] and FT [165] have variants that include the use of an electrolyser for producing hydrogen. The injection of hydrogen in the methanation and the FT processes increases the fuel output of the two technologies (see Table B.2). Fast Pyrolysis is a chemical conversion technology which produces oil from wood. This oil can be upgraded to diesel, that is the case of the Fast Pyrolysis with Upgrading technology [172].

Adv CHP consists of a system combining a SOFC and a GT. The outlet stream of the SOFC is at high temperature and contains unburned methane. Thus it has a high exergy content, which is exploited in the GT to produce electricity [173]. The integrated gasifier with fuel cell (FC) and GT has the same flowsheet as the Adv CHP, with the difference that instead of using methane as fuel input, it has a

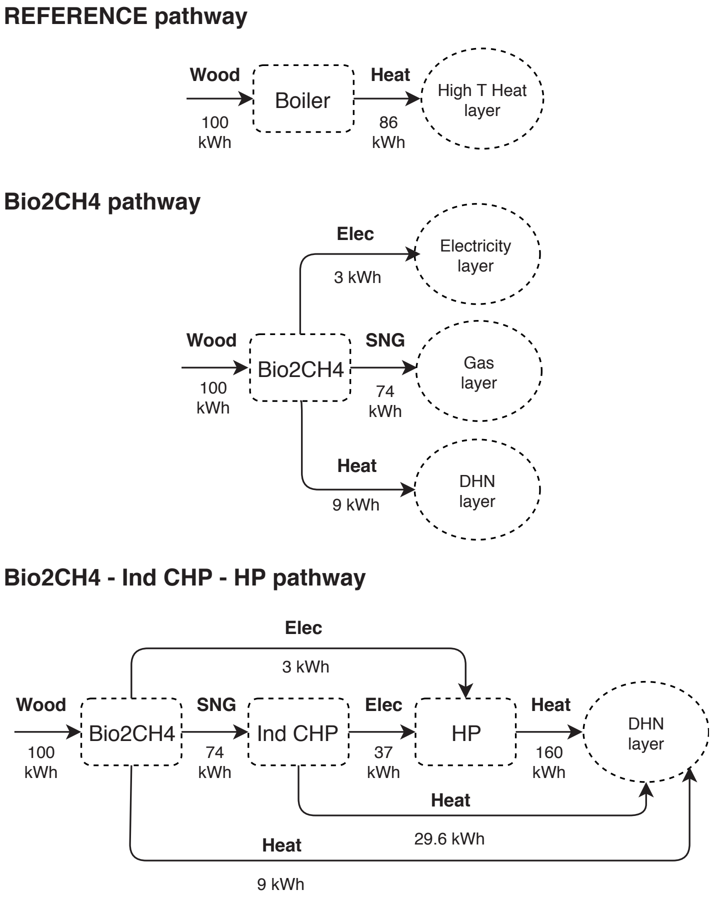

Figure 2.8 – Example of biomass conversion pathways: “Reference”, “Gasification & methanation (Bio2CH4)” and “Bio2CH4 – Ind CHP – HP” pathways.

gasifier providing fuel for the SOFC and the GT by converting wet wood into syngas [174].

The rest of technologies in Table 2.7 are assumed to be known by the reader, thus no description is provided in this chapter. Tables B.2 and B.3 contain the efficiency, economic and GWP_{const} data for the wood conversion units, which are the units in the “chemical conversion” group plus BIGCC, MGT and Gas-FC-GT from Table 2.7. The data for all the other units/technologies is available in [34].

Additional constraints/conditions are needed to force the different pathways:

- All the available 5000 GWh of wood are exclusively consumed by the technologies that are part of the pathway.
- There is only one unit having wet wood as an input in each pathway, i.e. a Bio2CH4 – Ind CHP (wood) pathway is not possible, as both units have wood as an input.
- The synthetic fuels generated by Chemical Conversion units have to be consumed by Technology 1 units if included in the pathway.
- The electricity generated by Technology 1 units has to be consumed by Technology 2 units if included in the pathway.
- The following units can only be used when they are part of the pathway: HPs, ThHPs, advanced combined heat and power and battery electric vehicles.

The last constraint links the production of fuels and electricity from wood to the deployment of the listed technologies. In the scenarios where the technologies in the “Technology 1” and “Technology 2” groups in Table 2.7 are not in the pathway, biofuels from chemical conversion units simply replace their respective fossil equivalents. The application of the constraints can be appreciated in the “Bio2CH4- Ind CHP – HP” pathway in Figure 2.8.

The operation ($\mathbf{Mult_t}$(j,t)) of the units that are not part of the pathways are determined through the optimisation of the system. As previously mentioned, the objective function is the minimization of $\mathbf{GWP_{tot}}$.

The usage of some units is set as constant across the scenarios. This is done to make the scenarios more realistic. Table 2.8 contains the units and the definition of their operation values as a function of the demand defined by the “Services Units”. Some of these technologies are also included in certain wood usage pathways, as they belong to “Technology 1” or “Technology 2” groups. In this case, the technology is duplicated in the model, meaning that there are two instances of the same unit in the model. This is merely a way to distinguish between the use of the unit which is independent of the pathway, and the use which is pathway-dependent. The first one is constant across the scenarios and it does not have to follow the constraints/conditions above defined. The second one is linked to the pathway, so it must follow the previously enumerated constraints/conditions. In this way, the pathway-dependent unit use is additional to the constant use common to all scenarios.

Table 2.8 – Operation values ($\mathbf{Mult_t}$(j,t)) for units which are constant across the scenarios.

Unit	Value
DHN HP	10% of Low T Heat
Dec HP	20% of Low T Heat
Ind Boiler Oil	5% of High T Heat
DHN Boiler Oil	1.5% of Low T Heat
Dec Boiler Oil	3.5% of Low T Heat
ThHP	7% of Low T Heat
PHEV & hybrid electric vehicle (HEV) car	10% of Mobility
BEV car	7% of Mobility

2.5 Evaluating biomass pathways scenarios for Switzerland in 2035

Figure 2.9 displays the evaluation of 56 scenarios by showing the relative variation of Annual GWP impact ($\mathbf{GWP_{tot}}$) and Annual Total Cost ($\mathbf{C_{tot}}$) with respect to a reference scenario. Table C.1 contains the results of the 56 scenarios. Each scenario evaluates the use of 5000 GWh of wood following a different usage pathway. The 56 scenarios are defined using the methodology described in section 2.4.2. The reference scenario corresponds to the pathway in which all 5000 GWh of wood are burned in boilers.

The scenarios can be classified within two groups: “old energy policies” and “new energy policies”. The “old energy policies” scenarios only consider the use of biomass chemical conversion processes listed in the first column of Table 2.7. The synthetic fuels produced from wood replace part of their corresponding fossil alternative. As an example, in the “old energy policies” scenarios there is no reduction in the final energy demand as chemical conversion processes are introduced without the promotion of efficient end-use technologies. The NEP scenarios represent energy policies that link the promotion of biomass chemical conversion processes to the deployment of end-use efficient technologies.

Scenarios using chemical conversion processes without electrolyser (Bio2CH4, FT, Pyro, PyroUp), which belong to the “old energy policies” scenarios group, are less advantageous than the reference scenario both in terms of GWP and Total Cost. Thus, directly burning the wood in boilers is better than conversion of wood to biofuels if the latter is not associated to the deployment of efficient technologies.

The scenarios evaluating chemical conversion pathways that include the use of electrolysers have a lower GWP than the reference scenario. This is explained by the fact that the excess electricity is transformed into an extra amount of synthetic fuel during the summer.

The electricity mix in all scenarios is highly renewable. The scenario with the lowest penetration of renewable electricity sources has 90% of its electricity supply from renewable origin. Consequently, the pathways in which produced electricity substitutes the electricity mix are penalized in terms of GWP. These are the pathways in which the unit belonging to Technology 1 has a high electrical efficiency, mainly decentralized and advanced CHP, and no unit from Technology 2 group is used. This can be explained by the fact that the electricity generated from the 5000 GWh replaces electricity which already has a low CO_2 content. The point with the highest GWP in Fig. 2.9 corresponds to the Pyro-Dec CHP pathway, which adds the conversion losses of the Pyrolysis to a high electrical efficiency.

The position of the pathways including advanced and decentralized CHP is improved when they include one of the units in Technology 2 group. HPs convert the high electricity production into heat supply. They replace boilers, reducing the fossil resources consumption. The use of battery electric vehicles transforms the electricity supply from the pathway into mobility services, which substitute conventional internal combustion engines vehicles (gasoline and diesel) in the scenario. HPs are about four times more efficient than any boiler, while battery electric vehicles are up to five times more efficient than internal combustion engine vehicles. Thus, the deployment of more efficient technologies is necessary to fully exploit the potential of biofuels, bringing a consequent reduction of the annual GWP impact indicator.

The point with the lowest GWP is the scenario evaluating the “Bio2CH4el – Adv CHP – BEV” pathway. This pathway maximizes the mobility service thanks to the use of the technologies with the highest electric efficiency (Adv CHP) and -SNG yield (Bio2CH4el).

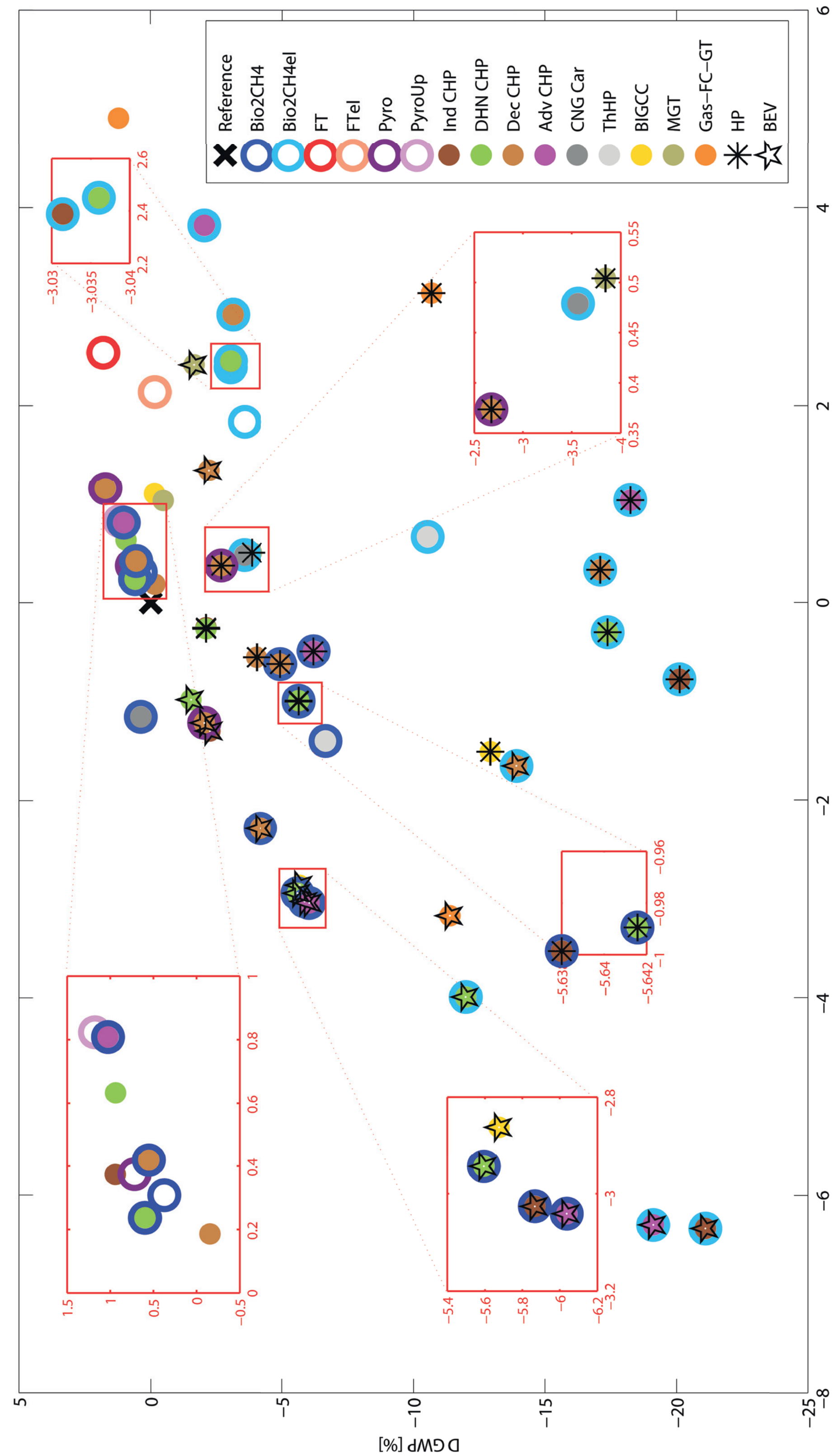

Figure 2.9 – Annual GWP impact and Total Cost relative values for the 56 scenarios compared to the Reference scenario.

2.6 Woody biomass and seasonal electricity storage, exploring the synergies

The characterization of the future Swiss energy system is based on the NEP scenario in 2050 [12] that the Swiss goverment uses as a basis to its Energy Strategy 2050. Figure 2.10 presents the monthly profiles of the electricity production for the NEP scenario in 2050. The per capita electricity production and demand are 811 Wyear/inhab. and 750 Wyear/inhab. respectively. This NEP scenario is based on a relatively high penetration of renewable electricity sources. The annual photovoltaic electricity production is increased to 140 Wyear/inhab. The monthly profiles show the contributions of CHP in the winter months and the excess electricity produced in summer. It also takes into account an increase of the height of certain dams which allows shifting around 30 Wyear/inhab. from summer to winter months [128]. In this scenario, around 4.9 TWh (62.3 Wyear/inhab.) corresponding to 7.7% of the annual production has to be stored or curtailed, as it cannot a priori be exported as neighbouring countries will experience the same excess production. It also represents 44.5% of the electricity produced by photovoltaic panels considered in the scenario.

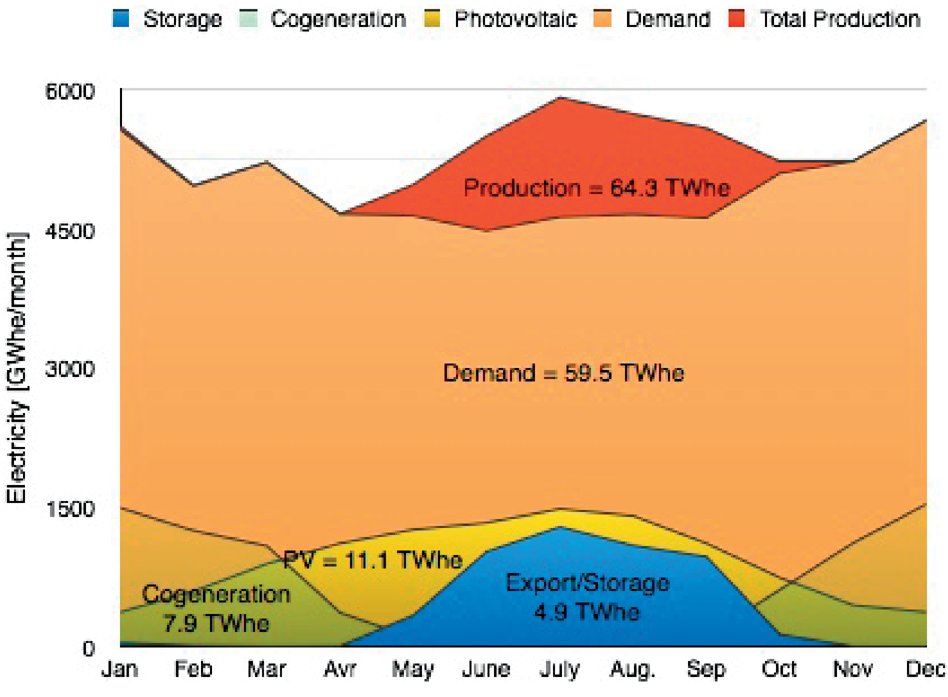

Figure 2.10 – Swiss electricity production and consumption in the NEP scenario for 2050.

This future summer excess corresponds to the current winter deficit that Switzerland covers with imports. Hence, seasonal storage would enable substituting the winter imports and increase significantly the energy independence of Switzerland while reducing the carbon footprint of its electricity. However, in the NEP scenario, it is planned that CHP is used to bridge the winter deficit, thanks to its capacity to jointly produce power and heat when both products are actually needed. In the NEP scenario, there is no more electricity deficit, and hence no need for seasonal storage.

Given that seasonal storage of electricity will a priori not be needed in Switzerland in 2050, an alternative use of its future excess electricity produced in the summer has to be found. In this context, biomass chemical conversion technologies combined with electrolysis are a good option for transforming the excess summer electricity into biofuels. This is the case for the wood-based gasification & methanation with electrolyser Bio2CH4el pathway (see appendix B.1.1), as well as the Fischer-Tropsch with electrolyser FTel pathway (see sections B.3.1).

The electricity-to-fuel efficiency of the FTel pathway is higher than that of the Bio2CH4el process, 78 % against 68 %. However, the later process is able to store more electricity per unit of biomass energy input (1.44 $kWh_e/kWh_{Biomass}$) than the FTel (0.54 $kWh_e/kWh_{Biomass}$). Therefore, the Bio2CH4el process is the best option as the amount of available biomass is limited.

Based on the results presented in [6], absorbing 4.9 TWh of excess electricity in the Swiss NEP energy transition scenario requires a 1.21 $GW_{WoodInput}$ (0.13 kW/inhab.) Bio2CH4el facility with a 1.76 GW_e (0.20 kW/inhab.) electrolyser. The annual woody biomass consumption of such a facility is 10.6 TWh (134 Wyear/inhab.), while its bio-SNG production is 10.1 TWh (127 Wyear/inhab.).

For calculating the values in the previous paragraph, the Bio2CH4el system is sized by considering the month with the highest surplus of electricity with the objective to use the entire surplus electricity in the electrolyser. The ratio between the electricity input in the electrolyser ($Elec_{in}$) and the wood input in the gasifier ($Wood_{in}$) takes the maximum value presented in [6] for the directly heated gasification system: $Elec_{in}/Wood_{in} = 1.445$. The wood input power is assumed to be constant along the year, thus the $Elec_{in}/Wood_{in}$ is lower for the other months. The gas output for month i ($Gas_{out,i}$) is calculated using Eq. 2.10-2.12. The necessary data for defining Eq. 2.10-2.12 is available in [6] (directly heated gasification system case). Figure 2.11 shows the behaviour of the system for 1 MJ of wood being gasified in one year. The Swiss electricity production and consumption profiles in the NEP scenario for 2050 are used to determine the electricity surplus profile.

$$x_i = Elec_{in,i}/Wood_{in,i} \tag{2.10}$$

$$Gas_{out,i}[MW_{SNG}] = 16.107 + 16.725 * x_i \qquad x_i \in [0, 0.161) \tag{2.11}$$

$$Gas_{out,i}[MW_{SNG}] = 16.894 + 11.838 * x_i \qquad x_i \in [0.161, 1.445] \tag{2.12}$$

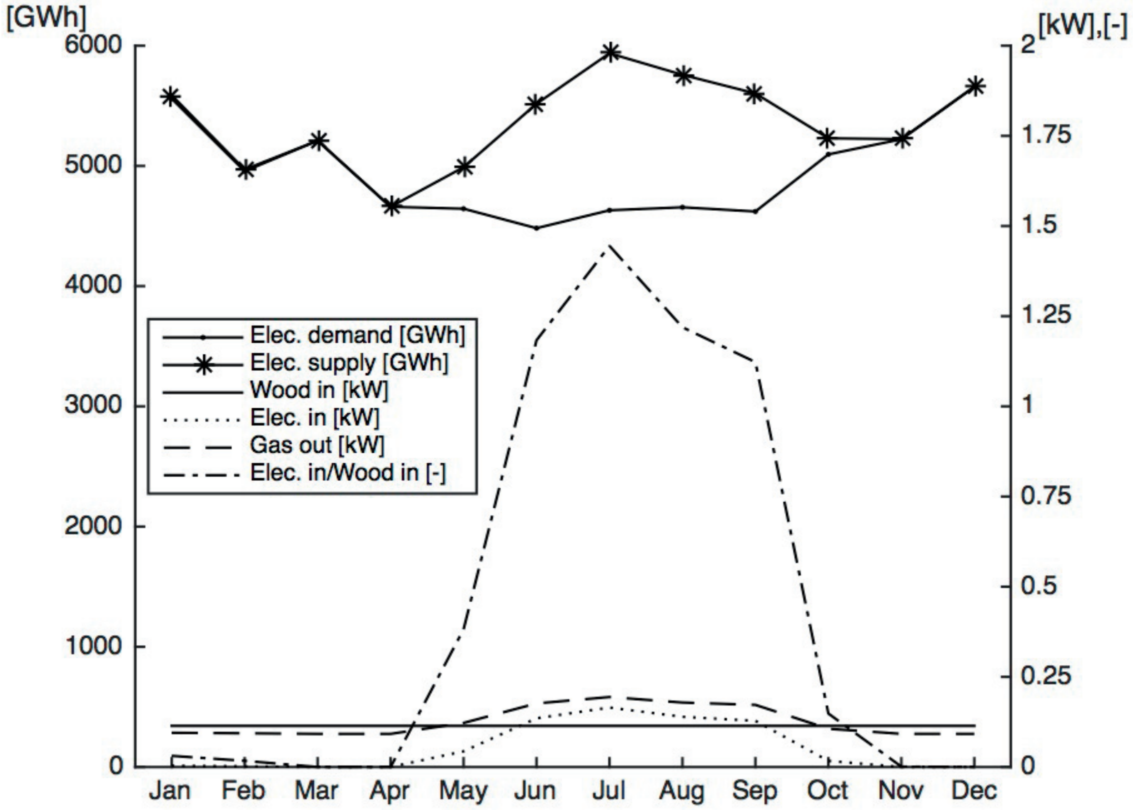

Figure 2.11 – Behaviour of the gasification & methanation with electrolyser (Bio2CH4el) system considering electricity supply and demand profiles in the New Energy Policies (NEP) scenario in 2050.

2.7 Non-linear optimisation to asses Swiss biomass utilisation in 2050

As discussed in section 2.5, the pathways including the Bio2CH4el technology are a priori the preferred ones for Switzerland. However, the implementation of this technology in the Swiss NEP scenario is constrained by the fact that almost 90% of the woody biomass resources are already used by other existing pathways, mainly wood boilers and CHP units for heat and electricity production [12]. The untapped biomass potential is only about 6 PJ, which is significantly below the amount required for storing all the excess electricity during summer: 38 PJ of woody biomass. Therefore, it is necessary to define alternatives to the NEP scenario in order to assess the impact of the implementation of this biomass pathway in the Swiss energy system in 2050.

Two alternatives are proposed: the gasification scenario and the photovoltaic scenarios. The scenarios are created using the model presented in section 1.4. They are designed through optimisation techniques. The evolutionary algorithm presented in [175] is chosen for the optimisation, since the model presented in section 2.7 has a non-linear formulation.

The model has seven input variable categories: socio-economics, efficiency, transport, heating and combined heat & power, renewable electricity, non-renewable electricity and cost [92]. In the two alternative scenarios, all the inputs are kept identical to those in the NEP scenario, except for the technology mix for distributed heating (heating and combined heat & power category), and the composition of the vehicle fleet (transport category). These are the decision variables of the optimisation problem to generating these alternative scenarios. The technology mix for distributed heating is composed of seven different technologies (see Table 2.9). Their role is to supply space heating and sanitary hot water to the households, industry and service sectors. The weight of each technology within the mix is expressed as a percentage of the total installed power for distributed heating. The installed capacity of the Bio2CH4el is also a decision variable of the optimisaiton problem.

The electricity exchange with neighbouring countries is not allowed. The lack of imports responds to the will of increasing the energy dependency of Switzerland. Regarding the exports, it is assumed that neighbouring countries will present the same seasonal production profile like Switzerland, hence there will be no demand for exporting the electricity.

In the two explored alternatives, the possibility of storing the CO_2 in the output of the methanation process is evaluated. The use of hydrogen for increasing the bio-SNG yield decreases the amount of CO_2 that can be captured, as the hydrogen uses the carbon from the CO_2 for the production of methane (see appendix B.1.1). The CO_2 stored can represent up to 30% of the equivalent CO_2 emissions of the Swiss energy system (point F1P4 in Table 2.9).

The gasification scenario

The gasification scenario is designed by minimising the equivalent CO_2 emissions under the assumption that no import of woody biomass is allowed.

The scenario is based on the gasification of woody biomass rather than direct combustion. To have more woody biomass available for gasification, the proportion of existing boilers in the technology mix for distributed heating is reduced, in favour of HPs (see Table 2.9, where NEP and F1P1 are the NEP and gasification scenarios respectively). The percentage of SOFC-GT, called “advanced CHP " in the model from section 1.4, is increased to compensate part of the increase in electricity demand due to the higher use of HPs. The share of the other technologies in the distributed heating mix (ThHP, CHP , thermal solar and electric heater) remains the same as in the NEP scenario.

In this gasification scenario excess electricity is also produced in the summer period (1’270 GWh), which is assumed to be converted into bio-SNG (5’676 GWh) thanks to the Bio2CH4el technology.

The results shows that the gasification scenario has 29 % lower equivalent CO_2 emissions in comparison to the NEP scenario with a slightly lower overall woody biomass consumption. In addition, it decreases the energy dependency of Switzerland as compared to the NEP scenario by 40% thanks to the new bio-SNG production.

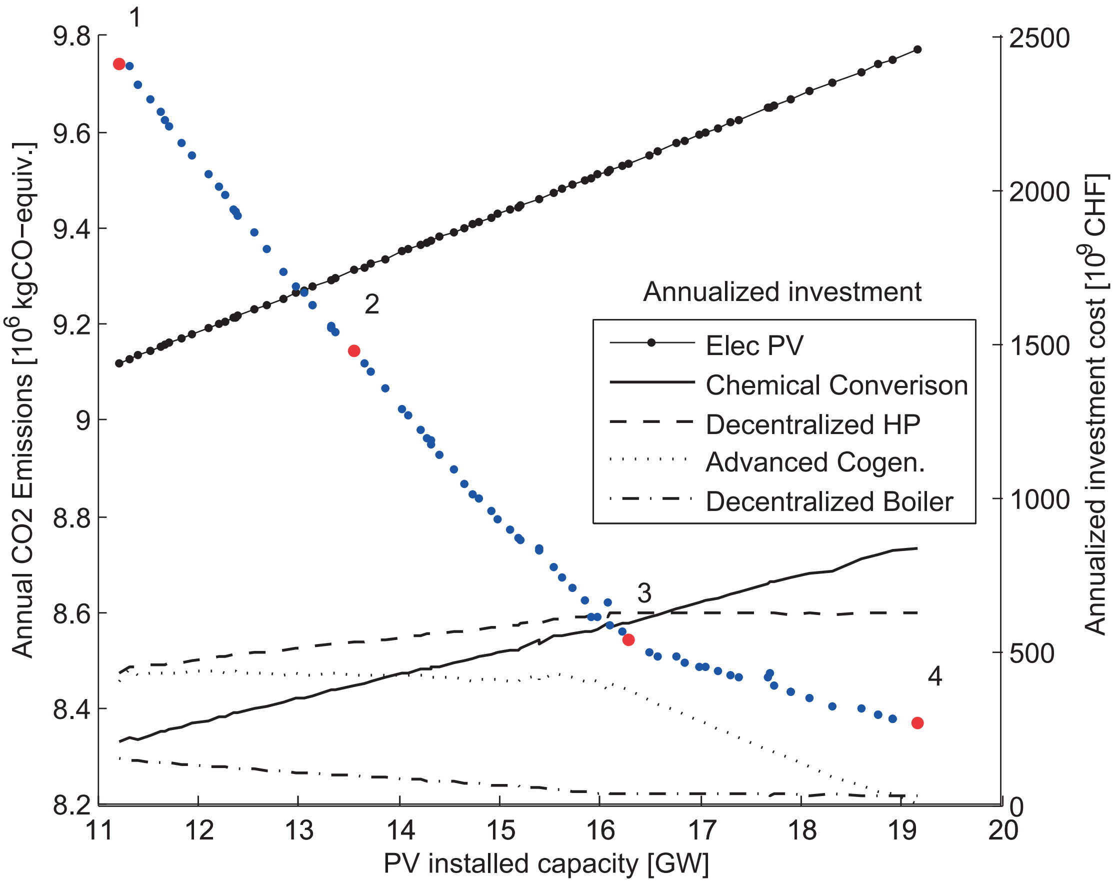

Figure 2.12 – Annucal CO2 Emissions and Annualized Investment Cost VS Installed Capacity PV.

The photovoltaic scenarios

With a technical potential estimated to 24 TWh [176], solar photovoltaics is the renewable electricity source with the highest untapped potential in Switzerland. In both the NEP and in the gasification scenarios less than half of this potential is actually exploited (11 TWh). An increase in the photovoltaic installed capacity combined with a mix of technologies consuming or transforming the photovoltaic electricity would reduce the energy dependency of the country. This translates into a significant reduction of the CO_2 emissions. Figure 2.12 shows how the annual equivalent CO_2 emissions change if the PV installed capacity is higher than the one considered in the NEP scenario. For generating the scenarios a multi-objective problem is solved. The two objectives are the minimisation of the CO_2 emissions and the minimisation of PV installed capacity. The PV installed capacity is minimised in order to obtain optimal CO_2 emissions for different PV installed capacity.

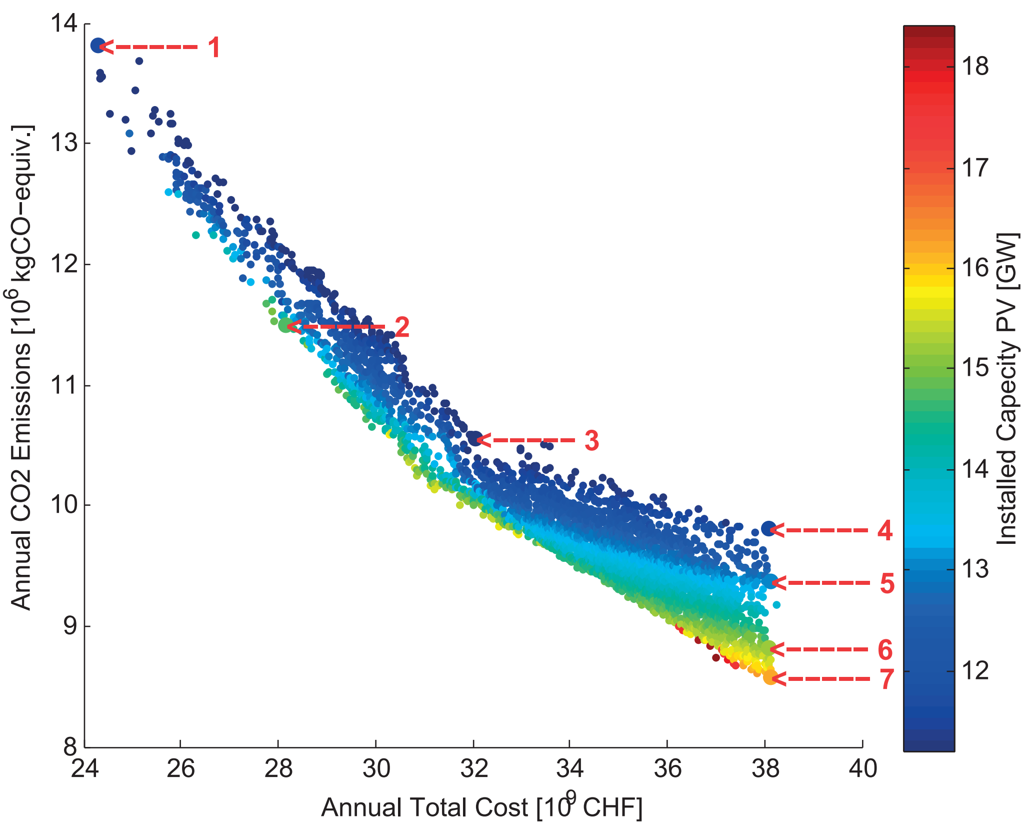

Figure 2.13 – Annucal CO2 Emissions VS Annual Total Cost VS PV Installed Capacity.

Table 2.9 contains the decision variables and output values of the highlighted points in Figure 2.12. From Figure 2.12, it can be directly concluded that the higher the PV penetration, the lower the CO_2 emissions. The electricity supplied by the additional installed capacity is used both to drive decentralized HPs and to feed electrolysers for increasing the production of bio-SNG. This use is compatible with the fact that Switzerland is expected to have no electricity deficit in 2050 (according to the NEP scenario), and that electricity export is not possible as neighbouring countries will experience the same production peaks like Switzerland. To meet these constraints, it is necessary to invest 0.3 Swiss Francs (CHF) in decentralized HPs and 0.6 CHF in the bio-SNG and electrolysis technologies for every CHF invested in PV capacity. The linear relation between investments is extracted from Figure 2.12.

The previously described strategy rises the consumption of woody biomass of the bio-SNG production facility, so the amount of woody biomass consumed by direct combustion technologies is decreased, under the assumption that no wood is imported. The extra amount of bio-SNG injected into the system replaces the fossil natural gas until the PV installed capacity reaches approximately 16.3 GW (point 3 in Figure 2.12). At this deployment level the decentralized HPs reach their maximum weight in the distributed heating mix. At this point, decentralized HPs cannot be the electricity sink for additional photovoltaic electricity. As there is no other technology being able to consume electricity whose capacity can be modified by the optimiser, the only option is to decrease the electricity production from other sources in order to accommodate the additional photovoltaic electricity. For this reason, the installed capacity of advanced CHP decreases (from 1% in point 3 to 0% in point 4). When reducing the installed capacity of advanced CHP , the optimiser then reacts by increasing the amount of CNG vehicles (from 0.2% in point 3 to 1.6% in point 4) and decentralized boilers (from 4.1% in point 3 to 5.2% in point 4) in order to consume all the bio-SNG produced by the biomass pathway, since we have set the constraint that no natural gas export is allowed. This explains the change on the slopes of the investment curves in Figure 2.12.

For this analysis the cost of the private passenger vehicles has been added into the model. The number of cars in Switzerland is assumed to grow linearly with population. As the number of cars per inhabitant has remained almost constant for the last 10 years (0.51 in 2005 vs. 0.53 in 2015), so the expected number of cars in 2050 is 4.79 millions for a 9.04 million inhabitants (0.53 car/inhabitant) [177]. Table 2.10 contains the considered investment cost for the types of cars. The cost taken into account into the model is the difference between the chosen vehicle fleet and 100 % gasoline/diesel vehicle fleet.

Figure 2.13 shows the annual equivalent CO_2 emissions against the total cost of the energy system. The colours of the points indicates the level of installed PV capacity. The decision variables and output values for the marked points are given in Table 2.9. The solutions presented in Figure 2.13 are the results of a multi-objective optimisation (MOO) problem. The objectives are the minimisation of the CO_2 emissions, the minimisation of total cost of the energy system, and the maximisation of the PV installed capacity.

It can be concluded that the vehicle fleet composition has an significant impact on both the CO_2 emissions and total cost of the Swiss energy system. F2P3 (point 3 in Figure 2.13) corresponds to an energy scenario in which the vehicle fleet is only composed by hybrid vehicles (70% plug-in hybrid and 30% hybrid vehicles). The scenarios with lower CO_2 emissions than F2P3 have a vehicle fleet with a high percentage of battery electric vehicles. F2P3 is the inflection point where the slope of the graph is modified due to the increasing penetration of battery electric vehicles.

Figure 2.14 shows the cost composition of the pareto front points of Figure 2.13. In the pareto front the increase in installed PV panels is linked to an increase in the investment in the vehicle fleet,

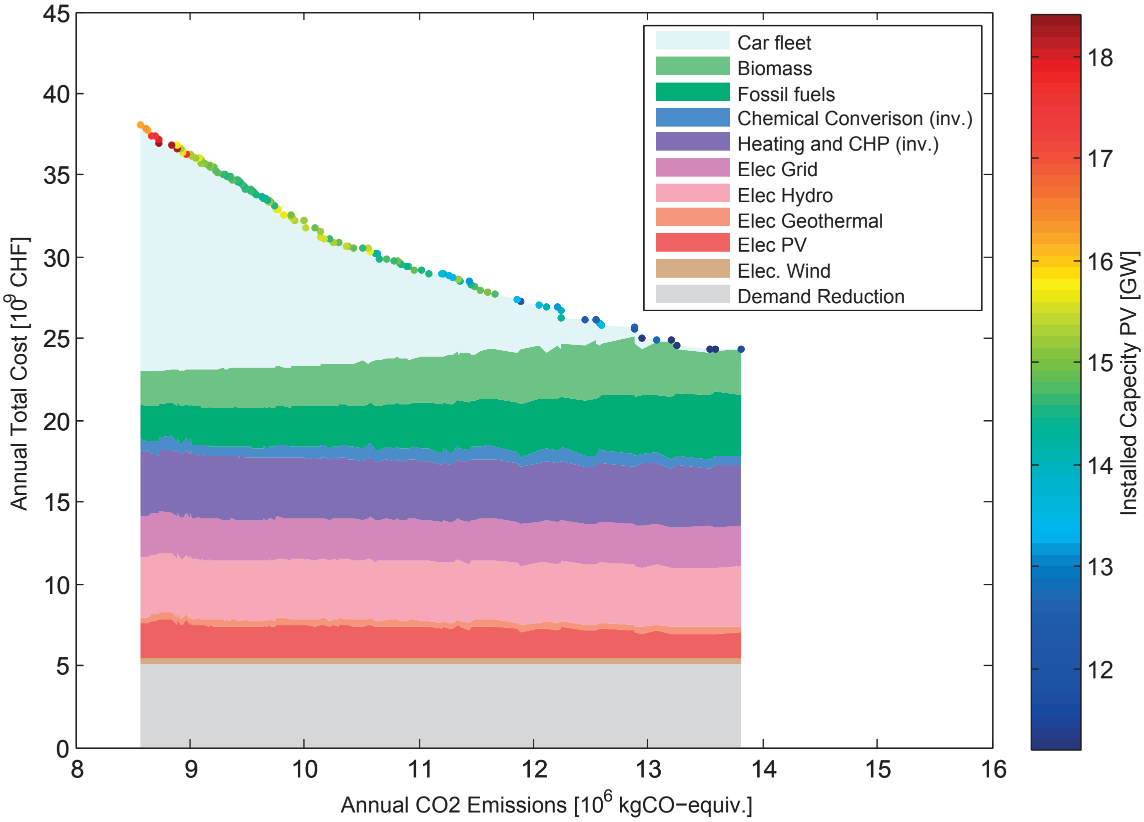

Figure 2.14 – Compostion of the cost of the pareto front points.

that corresponds to an increased penetration of plug-in hybrid and battery electric vehicles. The consumption of biofuels and fossil fuels decreases with increasing penetration of PV panels, which reflects the electrification of the vehicle fleet. The other of the cost categories do not show any strong relationship with the installed capacity of PV panels.

The points F2P4 to F2P7 (points 4 to 7 in Figure 2.13) represent energy scenarios with similar CO_2 emissions but different costs. The difference in total cost of the energy system can be explained by the level of deployment of PV. The higher the PV penetration, the lower the total cost of the energy system. The excess electricity from PV is used to produce bio-SNG according to the Bio2CH4el pathway, which results in lower cost of natural gas imports. Therefore, the deployment of PV panels in this scenario allows to reduce the CO_2 emissions and the dependency over imports, while maintaining the total energy system cost constant. This is a conclusion with far reaching implications for energy policy making.

Table 2.9 – Input and output data for the NEP scenario and the highlighted scenarios in Figures 2.12 and 2.13 for 2050.

Input / Output data		Scenario											
		NEP	F1P1	F1P2	F1P3	F1P4	F2P1	F2P2	F2P3	F2P4	F2P5	F2P6	F2P7
Vehicle types	Battery electric vehicles	21.9	85.0	84.8	84.1	85.0	0.0	1.2	0.0	81.3	82.9	82.6	84.4
	Hybrid vehicles	15.3	15.0	15.0	15.3	12.2	0.0	45.1	100.0	18.6	17.0	17.4	14.9
	Natural gas vehicles	2.1	0.0	0.0	0.2	1.6	40.1	17.8	0.0	0.0	0.0	0.0	0.5
	Hydrogen vehicles	4.4	0.0	0.1	0.3	0.7	0.0	0.6	0.0	0.1	0.0	0.0	0.1
	Gasoline/Diesel vehicles	56.3	0.0	0.1	0.1	0.5	59.9	35.3	0.0	0.0	0.1	0.0	0.1
Technology mix for distributed heating [%]	Electric HP	18.7	27.6	33.2	39.4	39.3	42.2	44.3	36.2	32.2	34.5	38.1	39.6
	ThHP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CHP	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	Advanced CHP	0.3	1.2	1.1	1.0	0.0	0.2	0.0	0.9	1.8	1.5	1.3	1.1
	Boiler	25.6	15.7	10.2	4.1	5.2	2.1	0.2	7.4	10.5	8.5	5.1	3.9
	Solar	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1
	Electric heater	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Installed capacity PV [GW]		11.21	11.21	13.55	16.28	19.16	11.77	14.71	11.21	11.56	13.06	15.15	16.22
Installed capacity SNG [GW_{WoodIn}]		0.00	0.37	0.70	1.07	1.50	1.15	1.45	0.96	0.68	0.79	0.99	1.07
Wood consumption [GWh]	Direct combustion	-12993	-11486	-8541	-5297	-1290	-2469	-1336	-6340	-8438	-7457	-5857	-5281
	SNG production	0	-3232	-6145	-9346	-12873	-10073	-12677	-8379	-5950	-6925	-8639	-9389
Electricity consumption for SNG [GWh]		0	-1270	-2608	-4188	-6118	-4766	-6357	-3742	-2383	-2904	-3798	-4204
SNG production [GWh]		0	2926	5676	8746	12240	9569	12254	7841	5417	6379	8048	8784
Natural gas import [GWh]		16257	9671	5200	0	0	12235	1431	2117	7817	5329	1409	69
Equivalent CO_2 emissions [10^6 tonnes]		13.6	9.7	9.1	8.5	8.4	13.8	11.5	10.6	9.8	9.4	8.8	8.6
Potential CO_2 capture [10^6 tonnes]		0	0.7	1.2	1.9	2.5	2.0	2.4	1.7	1.2	1.4	1.7	1.9
Total cost [10^9 CHF]		30.1	37.9	38.0	38.1	38.0	24.3	28.2	32.1	38.1	38.1	38.1	38.1

Table 2.10 – Unit cost for the passenger private vehicles.

Car Type	Unit Cost [CHF] [178]
Battery electric vehicle	63’854
Hybrid car	44’336
CNG	23’620
Fuel cell hydrogen car	69’000
Gasoline/Diese car	23’620

2.8 Conclusions

This chapter starts by evaluating the impact on CO_2 emissions and energy system cost of using woody biomass for different energy services: space heating, space heating & electricity, and space heating & mobility. The woody biomass pathways are considered to substitute the same amount of energy service supplied by fossil fuel pathways. Thus the CO_2 abatement potential of the woody biomass is directly proportional the amount of fossil fuel displaced by the woody biomass. Hence a substitution approach for the calculation of the impacts is followed.

The biomass pathway that offers the highest CO_2 saving is the “Bio2CH4el → SOFC-GT & CCS → Car-Elec". The mobility service provided by this pathway displaces CNG cars and the heating service substitutes natural gas boilers. A description of this scenario is provided in Figure 2.5. The CO_2 abatement potential is almost 10 times higher in this scenario than the reduction that would be obtained when natural gas boilers are simply substituted by wood boilers.

However, we show that the CO_2 abatement potential is highly dependent on the biomass and fossil pathways considered. Some woody biomass pathways actually generate more equivalent fossil CO_2 per unit of delivered service than their equivalent fossil pathway. For instance, the “Bio2CH4el - Boiler" pathway, which delivers only space heating, generates more CO_2 emissions than a fossil pathway composed of heat pumps driven by electricity from CCGT plant with CCS (Figure 2.2). Our analysis highlights the importance of considering the entire energy system with the substitution of services generated by fossil pathways. Focusing on the sole conversion efficiency of the biomass pathway may lead to non-optimal solutions.

Nevertheless, the substitution approach presents some shortcomings, such as that of not being able to consider the seasonal variability of the energy demand and supply. This is why we have developed a new methodology to evaluate the integration of woody biomass pathways in a large scale energy system. A MILP model of the Swiss national energy system is used to assess and compare the integration of different wood usage pathways. The resulting scenarios are evaluated in terms of total annual cost and global warming potential (GWP) as an environmental impact indicator. The scenarios belonging to the “old energy policies” only consider the use of biomass chemical conversion processes, e.g. FT. They have higher annual GWP impact and higher Annual Total Cost than the reference scenario, as the energy losses in the chemical conversion step are not compensated by the deployment of more efficient conversion technologies.

In addition, the inclusion of heat pumps (HPs) or battery electric vehicles (BEVs) in the pathways (as in the “new energy policies” scenarios) is a key aspect to reduce the annual GWP impact. The most promising pathways are those in which the main delivered energy service is mobility. In the resulting scenarios the use of BEV is promoted against conventional gasoline/diesel vehicles. Scenarios evaluating pathways which maximize heat supply thanks to the use of heat pumps are also well placed in terms of GWP, as the implementation of these pathways reduces the use of fossil technologies for heating such as boilers. Thus, linking the production of biofuels to the deployment of efficient technologies (such as HPs and BEVs) is necessary to fully exploit their potential and motivate the high investment costs. If this link is missing, then the production of biofuel is suboptimal in terms of GWP compared to the direct combustion of wood boilers. For example, the scenario evaluating the “Bio2CH4” (gasification-methanation) pathway has 0.4% higher GWP in comparison to the “Wood Boiler” scenario (reference scenario). If instead the production of gaseous fuel is combined with efficient technologies, like in the “Bio2CH4 → SOFC-GT → HP” pathway, the GWP is more than 6% lower compared to the reference scenario.

These figures are of course dependent on the configuration of the energy system into which the pathway is implemented, as that determines what energy sources are replaced when the 5000 GWh of wood are used. This is the reason why a realistic representation of a national energy system is chosen for the analysis.

The Swiss national energy system in year 2035 is used for the analysis due to the data availability for Switzerland and the previous work done by the authors in this domain. Nonetheless the proposed methodology can be applied to any other energy system at national or urban level. Furthermore, the conclusions drawn from this analysis can be extrapolated to other countries since Switzerland can be considered to be a representative country of the central European region and part of North America, as it has a clearly defined seasonal pattern and large exploitable wood potential.

The results also show that pathways including the Bio2CH4el technology present the most promising reduction in terms of GWP. That is mainly from the fact that the Bio2CH4el technology stores the excess renewable electricity into bio-SNG. In section 2.7, it is shown how in Switzerland in the year 2050, this technology would produce enough SNG to entirely cover the natural gas demand. In the best scenario, a reduction of 38 % of the Swiss CO_2 emissions can be achieved beyond the reduction already planned in the Swiss Energy Strategy 2050 represented by the NEP scenario of the Swiss government, which is itself already very ambitious as it reduces the CO_2 emissions by 50% compared to the 1990 baseline. Finally, the penetration of photovoltaics can be increased significantly beyond the scenario of the Swiss Energy Strategy 2050 without impacting significantly on the total cost of the Swiss energy system, while massively reducing CO_2 emissions and reliance on imports.

The conclusions of this chapter have been reached for the case of Switzerland, but we argue that these apply to all countries with similar energy systems, biomass availability and climatic conditions. These conclusions have far reaching consequences on energy policy making in terms of energy security, energy independence, climate policy and economics of the energy sector.

3 Investigating flexibility and storage options in the energy transition scenarios

3.1 State of the art

3.1.1 Existing models and studies

In literature there is a large number of publications describing methods and studies focused on the integration of renewable electricity sources. The amount of publications available stems from the combination of a large set of modelling frameworks with all existing technologies and strategies for the integration of renewable electricity. In order to reduce the scope of the literature review, we have decided to focus on publications with demand side management (DSM) options in their measures portfolio. As stated by Güttinger and Ahčin [54], DSM is an umbrella term that includes concepts such as demand response (DR), power-to-heat (P2H) and smart charging or vehicle-to-grid (V2G), among others. DSM does not refer to electricity storage. The decision to focus on publications considering DSM options is supported by the fact that DSM options have a low CAPEX and its implementation has low efficiency penalties. In addition, the implementation of DSM in energy modelling presents a certain complexity that is worth studying. The way energy consumers are modelled must be turned from a set of parameters defining a fix consumption behaviour into an active energy technology with its variables and constraints. The constraints must foresee the time dependence of buffer sizes and capacities or the time that loads can be shifted. For instance, in the case of smart charging, the buffer size (i.e. connected battery storage capacity) and capacity (i.e. charging power) depends on the number of cars that are parked and connected to the grid, hence on the driving profiles. In addition, the load cannot be shifted indefinitely since the car must be charged before its next use.

Table 3.1 contains a summary of the 15 retained publications which evaluate the implementation of DSM, flexible generation and electricity storage options. They are classified by system scope, spatial scope, time scale and timespan.

System and spatial scope

When considering the system scope the publications can be classified in 4 groups:

- **8 publications** have the power sector as system scope. These publications study the one-dimensional balance between electricity supply and demand. The properties and constraints of the electricity distribution grid are not part of the model, neither the electricity market. In 6 out of those 8 publication, the power sector model is complemented with models calculating the electricity demand for a certain sector, rather than defining it as a parameter. The sectors are heat for buildings, heat for industry, mobility considering the use of EVs, NG and H_2 consumption/production/distribution.
- **2 publications** are focused on the electricity market and the way its different actors (e.g energy seller, distribution system operator, aggregator and consumer [179]) interact.
- **3 publications** consider the complete national energy system, which includes the electricity and heat demand for the three main sectors (households, industry and services), the fuel and electricity consumption in the transport sector and the heat and power supply sectors. Studies having the national energy systems (NES) as system scope have a country as spatial scope, except for [66], which analyses the complete energy system of an island.
- **2 publications** look at decentralized energy systems for buildings. They only take into consideration the energy requirements and supply for buildings.

Only if the complete NES is modelled can all interactions and synergies between the different sectors of the energy system be considered in the problem. Hence systems considering only the power sector or the electricity market may not contemplate solutions that, besides being implemented outside the studied sector, may have a great impact on it. Some authors try to bridge this gap by complementing the power sector with the modelling of fractions of the national energy system, such as heat for buildings sector.

Time scale

There seems to be a consensus on the time scale. Almost all studies use the hourly resolution. Zakeri et al. [180] state that reducing the time scale from 1 hour to 15 minutes only increases the quality of the results by 1% when the power sector (PS) behavior is studied. Only Graditi et al. [179] uses the 15 minutes time scale, which is needed for the electricity market (EM) analysis since some actors in the market like ancillary services have actuation times below the hour [71]. Pina et al. [181] and Fehrenbach et al. [182] use models belonging to the TIMES family. As mentioned in section 1.1, TIMES models are evolution models whose timespan is broken down into a series of multiple-year or single-year periods, which at their turn are subdivided into time-slices (e.g. weekend in winter, Monday, Tuesday afternoon, etc), and each of these time-slices can have different time scale, the hourly being the most common. For example, in [181], each year was divided in 4 seasons, 3 days per season and 24 h per day. Nonetheless, Zerrahn and Schill [183] question the feasibility to properly model the behaviour of flexibility and storage option with the use of time-slices, since the model does not take into consideration chronology. Hence constraints imposing the same state of the storage system at the beginning and at the end of each time slice are necessary.

Methods

The calculation method for the operation of the energy system can be based on mathematical optimization or heuristics. Models using heuristic methods follow a decision tree to define the operation strategy. Technologies are dispatched according to their priority level which is specific to each possible case, i.e. there are different pre-specified hierarchies for a case with electricity deficit or for a case with electricity surplus. Heuristic methods can provide solutions to large problems faster than optimisation techniques [184]. Nevertheless, the solution is not warrantied to be optimal.

DSM options, flexible generation and electricity storage options

The DSM options studied in the publications in table 3.1 are grouped in 5 different categories. In addition, some authors [58] [185] did not attribute the DSM capacity to any specific sector or demand. In those two cases, the implementation of the DSM option is based on assumptions defining the curtailable fraction of the load. In [58], 1 - 16 MW of shiftable load is assumed for a total load of 40 - 49 GW. That capacity is used following a pre-defined operation strategy. In [185], the DSM capacity activation is decided through an optimisation problem which takes into consideration an electricity price signal.

DSM applied to power-to-heat (P2H) and appliances are the two most repeated options. Besides being attributed to a specific measure, some studies have rough data on the shiftable and curtailable portions of the load. This reality has already been pointed out by Salpakari et al. [60]. In [54], Güttinger and Ahčin wish to analyse the potential of DSM and vehicle-to-grid (V2G) for the city of Bern, Switzerland. For that purpose, a typical residential load adjusted to the power level of Bern is meant to describe the city's demand profile. Krüger et al. [66] have the implementation of DSM in five different sectors. The potential for the DSM options is based on the methodology from [186]. Kleinhans et al. [186] present an approach to model DSM as a storage technology with time-dependent maximum charging and discharging power and capacity. Kleinhans et al. computed profiles for DSM in industry, appliances, P2H, cooling and freezing and EV charging which are inputs for the model in [66]. Nonetheless, the curves are finally based on two parameters defined from statistics: maximum load available for DSM and the time frame management.

The P2H option is usually combined with the use of CHP as a flexible generation technology. This is done in most of the cases thanks to the implementation of heat storage tanks (i.e. hot water

(HW) tanks). Lund and Münster [51] defined a maximum storage size equivalent to one average day district heat production, while Salpakari et al. [60] also take into consideration the water volume of the DHN for storing heat by increasing its average temperature. On this regard, the TIMES model in [182] includes a detailed sub-model of the residential sector, which calculates the evolution of the building stock until 2050 at country level. Nonetheless all demand shifting is done thanks to heat storage tanks. To find studies implementing thermal load management, it is necessary to reduce the scope to the neighborhood [187] and building [188] level. These studies present more detailed models at demand side, which allow them to consider the use of thermal load management in addition to the capacity offered by HW tanks.

The V2G option is also contemplated in three of the reviewed publications. All authors have implemented the V2G option like a single storage system. Noel et al. [65] does not contemplate a driving profile for determining the cars availability. On the other hand a set of constraints are introduced, e.g. the battery level cannot go lower than 20% and the charging power always has a 7% reduction to represent the fact that not all cars are parked simultaneously. Güttinger and Ahčin [54] mention the usage of driving profiles in the calculation, nevertheless their definition and implementation into the model is not detailed.

From the performed literature review, we can list the following gaps:

- There is a generalised lack of accuracy when defining the potentials and constraints for the implementation of DSM options, which is accentuated when the system scope is the NES.
- What regards the P2H and CHP as flexible generation technologies, no publication with the NES as system scope takes under consideration the thermal load management of buildings, only thermal storage tanks are considered.
- With regards to V2G, the option is modelled as a single storage system, witout mention of how well that approach fits to reality.
- No publication with a NES of a country as system scope uses optimisation as calculation method, while including a detailed and well-documented implementation of P2H, flexible CHP and V2G.

Table 3.1 – Review of models and studies considering DSM options.

	System scope [a]	Spatial scope	Time scale	Timespan	DSM options[b]	Flexible generation [c]	Storage options [d]	Calculation method	Model available
Richardson and Harvey [58]	PS	Region	Hourly	1 year	NS	-	PHS	Heuristic	No
Marzooghi et al. [185]	EM	Country	Hourly	1 year	NS	GT	BAT	Optimisaiton	Yes
Noel et al. [65]	PS, H4B, EV	Region	Hourly	4 years	P2H, V2G	GT	H2S	Heuristic	No
Salpakari et al. [60]	PS, H4B	City	Hourly	3 years	Ref, P2H, App	CHP	-	Optimisation	Yes
Graditi et al. [179]	EM	District	15 min.	1 day	App	-	-	Optimisation	Yes
Güttinger and Ahčin [54]	PS, H4B, EV	City	Hourly	1 year	App, P2H, V2G	CHP	-	Heuristic	No
Ahčin and Šikić [187]	DES	Neighborhood	Hourly	1 year	P2H	CHP	-	Optimisation	Yes
Zakeri et al. [180]	NES	Country	Hourly	1 year	NS, P2H	CHP	BAT	Heuristic	Yes
Lund and Münster [51]	NES	Country	Hourly	1 year	P2H	CHP	-	Heuristic	No
Pensini et al. [189]	PS, H4B	Region	Hourly	1 year	P2H	-	-	Heuristic	No
Ali et al. [188]	DES	Building	Hourly	1 year	P2H	-	-	Optimisation	Yes
Schaber et al. [64]	PS, H4B, H4I, NG, H2	Country	Hourly	1 year	P2H	CHP, GT	PHS, H2	Optimisation	No
Krüger et al. [66]	PS	European	Hourly	1 year	Ref, P2H, App, V2G, Ind	CSP, BIOPP	PHS, CAES, H2	Optimisation	No
Pina et al. [181]	NES	Island	Multi-time	20 years	App	DE	-	Optimisaiton	No
Fehrenbach et al. [182]	PS, H4B	Country	Multi-time	40 years	P2H	CHP, GT	PHS	Optimisaiton	No

[a] Power sector: PS, Electricity market: EM, Heat for buildings: H4B, Electric vehicle: EV, Decentralised energy system: DES, National energy systems: NES, Heat for Industry: H4I, Natural Gas sector: NG, H_2 sector: H2.

[b] Not specified: NS, Power-to-heat: P2H, Refrigeration: Ref, Appliances: App, Vehicle-to-grid: V2G, Industry: Ind

[c] Combined heat and power: CHP, Concentrated solar power: CSP, Biomass power plant: BIOPP, Diesel engine: DE.

[d] Pumped Hydro Storage: PHS, H_2 storage: H2S, Batteries: BAT.

3.1.2 Space heating demand calculation

The vast majority of current studies on the integration of renewable energy sources consider that the electricity demand profile will retain its current shape in the future energy scenarios [190]. However, this may not be the case in the future, it is important therefore to isolate the components of the demand curve that are expected to have an important change in absolute values and shape. One of the most significant dimensions is the electricity consumption for space heating (SH). In France, in the last decade, the sensitivity of peak load has passed from an increase of 1.7 GW per drop of degree centigrade in 2003 to an increase of 2.6 GW in 2011 due to the adoption of HPs and direct electric heating (DEH) systems. That has brought the peak load in France from 85 to 100 GW (+17%) [190], an increase that is not correlated with the demographic growth (about 5% in that period [191]). In Switzerland, the electricity consumption for SH (HP and DEH) represents 7% of the annual electricity consumption, reaching 15% if the percentage is calculated for winter consumptions only [192].

Conversely to electricity, heating demand in buildings is not measured at national level, since there is no national supplier for thermal energy. Hence its annual demand and hourly profiles needs to be estimated. The approaches to calculate it can be grouped in bottom-up and top-down. The bottom-up approach consists in building the national profile by addition of specific profiles. For example, Calise et al. [193] have run 160 simulations for each combination of building age/size/type. The simulations have been performed with the TRNSYS software. Yao and Steemers [194] followed the same approach, but, in this case, a thermal resistant network method was used for the calculation of the heating profile. Boßmann and Staffell [190] have used the FORECAST model [195] to calculate the specific sector-application annual consumption. These informations have been added to hourly load profiles from field surveys, simulation models and official databases in order to decompose the electricity consumption of a base year, and isolate the electricity consumption for SH.

The top-down approaches are mainly focused on defining the impact of temperature on the national electricity demand [196] and the way electricity demand forecast. Taking into consideration weather forecasts can significantly improve the accuracy of the electricity demand predictions [197]. The forecast in most cases is performed with daily resolution, nonetheless some authors such as Marvuglia and Messineo [198] use artificial neuronal networks models with weather data as input for creating hourly forecast of the national electricity demand. Nonetheless, these studies do not allow to isolate the part of electricity demand related to SH.

From the studies reviewed in table 3.1, only Noel et al. [65] and Pensini et al. [189] have computed the aggregated hourly heating profile based on the top-down methodology proposed by Pensini et al. [189], which considers heating degree days and natural gas consumption data for calculating the aggregated heating load. However, they only use their methodology to calculate the heating load for fossil fuel boilers. They do not isolate the electricity consumption corresponding to SH from the electricity demand profile.

To put it in a nutshell, the main gap found in literature is the lack of existance of a methodology for isolating the electricity consumption corresponding to SH from the electricity national demand profile based on a top-down approach. On the other hand, bottom-up approaches are widely used by authors, but their main drawback is their data and computational needs.

3.2 Author's contribution

In this chapter, we detail the development of a model which aims at bridging the gaps presented in the literature review. The model developed by the author includes the implementation of several DSM and flexible generation options. Special attention is put to overcome one of the main gaps found on literature: the lack of accuracy in defining potentials and constraints for DSM options.

The model that is presented in this chapter is not created from zero. It has its base on the MILP model presented in the supplementary information (SI) of [34]. The decision to use the MILP model as a starting point is supported by three facts:

- The model is clearly documented and explained in the SI [34], which facilitates the implementation of new technologies and features.
- Having the NES as system scope allows to cover all interactions and synergies between different sectors, e.g. power and heating sector.
- The MILP formulation allows having an optimal solution to the problem.

The MILP model [34] has a monthly time scale. Hence our first contribution consists on increasing the time resolution from monthly to hourly.

In addition to increasing the model time resolution, we have implemented new storage and flexibility options. H_2 and NG storage are added into the model, in this way, the production of H_2 and SNG can be used as open-loop electricity storage solutions. Regarding close-loop technologies, we have reworked the formulation describing the operation of hydro dams in the original MILP model in order to have the water inflows into the dams as input data instead of the electricity production profile, bringing the implementation of the technology closer to reality.

Regarding the implementation of DSM, we have introduced the possibility to use P2H, together with the use of flexible CHP in buildings. The operation of these two options depends on the thermal storage offered by buildings. We have characterised the thermal storage, taking into consideration the thermal load management and thermal storage tanks for buildings at decentralized level. The formulation developed to include P2H and flexible CHP at decentralized level can be reproduced at centralized level (DHN). Nonetheless the work is focused on the decentralized level since we had access to results of the operation of a set of buildings representing the Swiss building stock, which had been generated using a model predictive control (MPC) model. These results are the basis for defining the potential for thermal load management and the use of thermal storage tanks in Switzerland.

EV smart charging is the other DSM that has been included. We have chosen smart charging over V2G because, as it has been reported in the introduction of this thesis, current research places V2G as a player in the ancillary services market. Ancillary services act the time level of minutes or seconds, hence they cannot be studied with a model having the hour as time step. The way we have defined smart charging allows to consider several cars with different driving profiles for a better reproduction of the cars use at national level in comparison with the implementations found in the literature review.

At the demand side, we present a novel methodology for calculating the electricity consumption related to electric SH. The methodology is used to remove the part corresponding to SH from the national electricity profile used as input to the model. Furthermore the renewable production profiles for wind and PV are computed taking into consideration their future locations. Thus they are not based on historical production profiles of a specific installation.

Last but not least, all new implementations are dully explained with their sets of equations, variables and parameters, following the formulation used in the SI in [34], and all data required for the definition of the potential has been clearly referenced in order to guaranty the reproducibility and adaptability of the model and its inputs and assumptions.

Finally the methodology is applied into a case study that analyses the short and long term storage and flexibility options to warranty the absence of electricity imports in Switzerland in 2035.

3.3 A MILP model for analyzing the integration of intermittent renewable energies

In this section we present a set of developments whose goal is to create a model for studying the integration of intermittent renewable energies. The new developments are added into an already existing model. The starting point for this work is the MILP model presented in the supplementary information (SI) in [34]. This model takes into consideration all sectors of a NES: households, industry, services and transport. It is based on a monthly time scale. The model is dully presented in the SI in [34]. From this point on, authors will refer to the MILP model in [34] as the “MILP model".

Since the main objective of this work is to test the suitability of a set of technologies to accommodate the stochastic renewable electricity sources, the variables referring to the installed capacity of the technologies in the model will be constraint. In this way, energy scenarios can be created. Technically, this is done by defining equal minimum and maximum installed size of the technology

(f_{min} and f_{max}), or equal minimum and maximum relative share of a technology in a layer ($f_{min,\%}$ and $f_{max,\%}$) in the model. In this way a scenario is defined setting the installed size for each of the electricity supply technologies (technologies in the TECH OF EUC (ELECTRICITY) set), and the relative share of the heating and transport technologies in their respective layers (technologies in TECH OF EUC (HEAT HIGH T), TECH OF EUC (HEAT LOW T), TECH OF EUC (MOB. PASS.) and TECH OF EUC (MOB. FR.)).

3.3.1 Implementation of the hourly time resolution

As it has been discussed in section 3.1.1, the most appropriate time resolution for studying the integration of renewable energies is the hourly one. In a first effort to run the model with hourly time steps, the annual share of lighting end-uses ($\%_{lighting}$), the annual share of SH end-uses ($\%_{sh}$), and the period capacity factor ($c_{p,t}$) are changed from a monthly to a hourly resolution. The time periods duration (t_{op}) is modified to 1 hour in the model.

However it was not possible to start the optimization problem due to memory issues. The attempts were done with a desktop computer with an Intel(R) Xeon(R) CPU E3-1240 V2 3.40 GHz processor, 8.00 GB of installed memory (RAM) and having the virtual memory managed by the system. The computation process was stopped because the system was running out of memory when loading eq. 17 of the model in [34]. This equation defines the operation strategy for the decentralized heating technologies. It warranties that the relative use of each technology in each period is constant, except for the solar thermal, which has priority since it has zero operational cost.

Hence we propose a modified formulation of the model in order to avoid the use of Eq. 17 in [34] while maintaining an equivalent operation strategy for the decentralised heating technologies, and the hourly time resolution. In order to facilitate the better understanding of the new formulation, we would like to recommend the reader to skim through the first section of the SI in [34], where the equations, variables and parameters of the original MILP model are explained.

As mentioned the first modification consist on deleting Eq. 17. To warranty that solar thermal has priority over the other decentralized heating technologies (e.g. decentralised boilers), its heat supply is discounted to **EndUses***(HeatLowTDec)* (Eq. 3.1). Furthermore, it has been assumed that solar thermal technologies can be also installed in buildings connected to district heating networks (DHNs). The calculation of **EndUses***(HeatLowTDHN)* (Eq. 3.2) is modified to apply this new assumption. In order to respect the linearity of Eq. 3.1 and Eq. 3.2, the ratio centralized over total low-temperature heating ($\%_{Dhn}$) is defined as parameter, which is explicitly calculated in Eq. 3.3.

$$\begin{aligned}&\mathbf{EndUses}(HeatLowTDec,t) = (\mathbf{EndUsesInput}(HeatLowTHW)/\sum_{t\in T} t_{\text{op}}(t)+ \\ &\mathbf{EndUsesInput}(HeatLowTSH)\cdot \%_{sh}(t)/t_{\text{op}}(t) - \mathbf{F_t}(Dec_{\text{Solar}},t))\cdot(1-\%_{\text{Dhn}}) \qquad \forall t\in T \quad (3.1)\end{aligned}$$

$$\begin{aligned}&\mathbf{EndUses}(HeatLowTDHN,t) = (\mathbf{EndUsesInput}(HeatLowTHW)/\sum_{t\in T} t_{\text{op}}(t)+ \\ &\mathbf{EndUsesInput}(HeatLowTSH)\cdot \%_{sh}(t)/t_{\text{op}}(t) - \mathbf{F_t}(Dec_{\text{Solar}},t))\cdot \%_{\text{Dhn}} \qquad \forall t\in T \quad (3.2)\end{aligned}$$

$$\%_{\text{Dhn}} = \frac{\sum_{i\in \mathit{TECH\ OF\ EUT(HeatLowTDHN)}} f_{min}(i)}{\sum_{j\in \mathit{TECH\ OF\ EUC(HeatLowT)}} f_{min}(j)} \qquad (3.3)$$

A parameter ($Ffix_{Solar}$) and an equation (Eq. 3.4) are added to fix the decentralised solar thermal installed capacity. A second equation defines the operation in each period (Eq. 3.5). Since solar thermal is treated differently in comparison to the other heating and CHP technologies, Eq. (3.6,3.7,3.8) do not apply to it anymore. The parameter $f_{min}(Solar)$ is thus always equal to zero.

$$\mathbf{F}(Dec_{\text{Solar}}) = Ffix_{\text{Solar}} \qquad (3.4)$$

$$\mathbf{F_t}(Dec_{\text{Solar}},t) = \mathbf{F}(Dec_{\text{Solar}})c_{p,t}(Dec_{\text{Solar}},t) \qquad t\in T \quad (3.5)$$

$$\mathbf{F_t}(j,t) \le \mathbf{F}(j)c_{p,t}(j,t) \qquad k = Dec_{Solar}, \forall j\in TECH\setminus\{k\}, \forall t\in T \quad (3.6)$$

$$\sum_{t\in T}\mathbf{F_t}(j,t)t_{op}(t) \le \mathbf{F}(j)c_p(j)\sum_{t\in T} t_{op}(t) \qquad k = Dec_{Solar}, \forall j\in TECH\setminus\{k\} \quad (3.7)$$

$$\sum_{i\in RES\cup TECHX\setminus(STO\cup Dec_{Solar})} f(i,l)\mathbf{F_t}(i,t) + \sum_{j\in STO}(\mathbf{Sto_{out}}(j,l,t) - \mathbf{Sto_{in}}(j,l,t)) - \mathbf{EndUses}(l,t) = 0 \qquad \forall l\in L, \forall t\in T \quad (3.8)$$

Eq. 3.9 defines the operation strategy for the heating and transport technologies. The relative use of each technology in each period should be constant. This equation warranties the operation strategy that was defined by the problematic constraint Eq. 17 in [34], and makes dispensable the use of Eq. (18,19,20) from [34]. Hence they are removed together with the variable $\mathbf{Y_{Solar}}$.

$$f_{min,\%}(j)\sum_{j'\in \mathit{TECH\ OF\ EUC}(euc)\setminus Dec_{\text{Solar}}}\mathbf{F_t}(j',t) \le \mathbf{F_t}(j,t) \le f_{max,\%}(j)\sum_{j'\in \mathit{TECH\ OF\ EUC}(euc)\setminus Dec_{\text{Solar}}}\mathbf{F_t}(j',t)$$
$$k = Electricity, \forall euc\in EUC\setminus k, \forall j\in \mathit{TECH\ OF\ EUC}(euc), \forall t\in T \quad (3.9)$$

However, if because of the operation strategy imposed by Eq. 3.9, CHP systems are active during periods with electricity excess, fuel will be used to produce electricity that will find no consumer. Thus this operation strategy may lead to non-optimal operation of the heating system from an energy and economic point of view. In that case, boilers should provide the heating service. Eq. (3.10,3.11,3.12,3.13) are implemented to avoid that to happen. They are based on the idea that decentralized CHP systems are installed in combination with auxiliary boilers. In other words, a building with a CHP system also have a peak boiler. These boilers can be operated when the use of CHP systems induces excess electricity production. This use of auxiliary boilers combined with CHP system is introduced in [92]. Only a percentage ($\%_{CogenBoiler}$) of the installed capacity of boilers is assumed to be able to work as auxiliary boilers. They do not represent an extra capacity to the existing boilers, hence their use as auxiliary systems is limited by Eq. (3.11,3.12,3.13).

$$\sum_{i \in AUX\ REPLACED(j)} \mathbf{F_t}(i,t) \leq \mathbf{F}(j)\mathbf{\%_{CogenBoiler}} \qquad \forall j \in REPLACED, \forall t \in T \quad (3.10)$$

$$\sum_{t \in T} \Big(\sum_{i \in AUX\ REPLACES(j)} \mathbf{F_t}(i,t) + \mathbf{F_t}(j,t)\Big) t_{\mathrm{op}}(t) \leq \mathbf{F}(j) c_{\mathrm{p}}(j) \sum_{t \in T} t_{op}(t) \qquad \forall j \in REPLACES \quad (3.11)$$

$$\mathbf{F_t}(j,t) + \sum_{i \in AUX\ REPLACES(j)} \mathbf{F_t}(i,t) \leq \mathbf{F}(j) \qquad \forall j \in REPLACES, \forall t \in T \quad (3.12)$$

$$\sum_{i \in AUX\ REPLACES(j)} \mathbf{F_t}(i,t) \leq \mathbf{F}(j) \qquad \forall j \in REPLACED, \forall t \in T \quad (3.13)$$

Eq. (3.14,3.15) are added into the model to avoid the optimiser to increase the installed capacity of the CHP technologies aiming to have more capacity for the auxiliary boilers. Eq. 3.15 applies to both DHN and decentralized heating, hence Eq. 24 in [34] is deleted. The parameter $\%_{Peak_{DHN}}$ in [34], which defines the ratio peak/maximum monthly average DHN heat demand is substituted by $\%_{\mathrm{Peak_{HeatLowT}}}$, fixing the ration peak/maximum average hourly low temperature heat demand.

$$\mathbf{HeatLowT_{max}} = \max_{t \in T} \big\{ \mathbf{EndUses}(HeatLowTDHN, t) + \mathbf{EndUses}(HeatLowTDec, t) \big\} \qquad \forall t \in T \quad (3.14)$$

$$\mathbf{F}(j) = \mathbf{HeatLowT_{max}} f_{\min}(j) \%_{\mathrm{Peak_{HeatLowT}}} \qquad k = Dec_{Solar}, \forall j \in TECH\ OF\ EUC(HeatLowT) \setminus \{k\} \quad (3.15)$$

The inputs from and outputs to the layers (f) of an auxiliary boiler are calculated as the opposite to the ones of the CHP technology that is substituting, plus the inputs and outputs of the boiler itself (see table 3.2 for an example). In this way, the $\mathbf{F_t}$ of the CHP technology does not change, hence Eq. 3.9 is respected. The replacement is only done at the layer balances.

Table 3.2 – Calculation fo the layer input and output for an auxiliary decentralised NG boiler that can replace decentralised NG CHP systems.

Technology	**Inputs from and outputs to the layers**[a]		
	ELECTRICITY	NG	HEAT LOW T DECEN
-(Dec CHP NG)	-0.957	2.174	-1
Dec Boiler NG	0	-1.111	1
Aux Boiler	-0.957	1.063	0

[a]A negative value represents an input from the layer (consumption). A positive values is represents an output to the layer (production).

REPLACED set includes the CHP technologies in TECH OF EUC (HEAT HIGH T) and TECH OF EUC (HEAT LOW T) sets (see Figure 1 in [34]). REPLACES set contains the boilers in the same two sets. The auxiliary technologies are parellely listed in two sets (AUX REPLACED and AUX REPLACES). The content of AUX REPLACED and AUX REPLACES is the same, the difference is the way the technologies are grouped in subsets. AUX REPLACED (*replaced*) subset groups the auxiliary technologies acting as auxiliary technology of the *replaced* CHP system in REPLACED. For example, AUX REPLACED (*DecCHPng*) contains DecCHPng-AUXBOILERng, DecCHPng-AUXBOILERwood and DecCHPng-AUXBOILERoil. AUX REPLACES (*replaces*) contains the auxiliary technologies using the *replaces* boiler. For example, AUX REPLACES (*DecBOILERng*) has DecCHPgas-AUXBOILERng, DecCHPoil-AUXBOILERng, AdvCHPng-AUXBOILERng and AdvCHPh2-AUXBOILERng. TECHX set is equivalent to the union of the technologies in TECH set merged with the auxiliary technologies, i.e. technologies in AUX REPLACES or AUX REPLACED.

This current version of the model requires about 20 minutes to be solved with the desktop computer whose characteristics have been reported earlier in this section.

3.3.2 Implementation of hydropower dams

In the version of the model presented in [34], the hydro dams are represented using three technologies:

- *Hydro dam* represents the already installed capacity for hydro dams, whose installed capacity is fixed.
- *New hydro dam* represents the new installed capacity for hydro dams.
- *Storage hydro* is defined as an electricity storage technology. It is meant to use the 2400 GWh [128] of possible supplementary storage capacity to shift production from periods with excess electricity to periods with electricity surplus. Shifting production only means producing it

later in time, hence there is no efficiency penalty.

The period capacity factor ($c_{p,t}$) is the same for *hydro dam* and *new hydro dam*, and it is calculated taking into consideration historical data on net electricity productions from dams. The dam net electricity production in a period is equivalent to the dam electricity production in that period minus the electricity consumed by its pumps for electricity storage in the same period.

For our extended version of the MILP model, the electricity production profile does not depend anymore on the historical production profiles, which have been substituted by the profiles reproducing the natural water inflow into the dam. And thanks to the new formulation the optimiser defines the electricity production profile for hydro dams.

The $c_{p,t}$ for *hydro dam* and *new hydro dam* are calculated considering the water inflows into the dams. Hence this change implies that electricity supply of the two technologies is calculated assuming that all water inflows are directly turbined. Then the *storage hydro* storage capacity ($\mathbf{F}(StoHydro)$) is modified to include the electricity storage capacity of the existing dams ($ExistSto$) plus the possible increase ($f_{max}(turbines)$). That implies rewriting Eq. 21 in [34] into Eq. 3.16. Furthermore the possibility of using the dams for pumping-turbining water is implemented by adding the technology *PumpedHydro*. Its efficiency of storage input from and outptut to the electricity layer are 0.8 ($\eta_{sto,in}(PumpedHydro, Elec)$) and 1 ($\eta_{sto,out}(PumpedHydro, Elec)$) respectively [199]. Eq. 3.17 is added to warranty that the sum of the outputs from the two storage technologies and *HydroDam* and *NewHydroDam* does not exceed the installed capacity of the turbines. Eq. 3.18 avoids the electricity consumed by the pumps for storage ($\mathbf{Sto_{in}}(PumpedHydro,Elec,t)$) to be higher than the pumps installed power $f_{max}(pumps)$.

$$\mathbf{F}(StoHydro) \leq ExistSto + f_{\max}(turbines)\frac{\mathbf{F}(NewHydroDam) - f_{min}(NewHydroDam)}{f_{max}(NewHydroDam) - f_{min}(NewHydroDam)} \tag{3.16}$$

$$\begin{aligned}&\mathbf{Sto_{out}}(StoHydro, Elec, t) + \mathbf{Sto_{out}}(PumpedHydro, Elec, t) + \mathbf{F_t}(HydroDam, t) + \\ &\mathbf{F_t}(NewHydroDam, t) \leq \mathbf{F}(HydroDam) + \mathbf{F}(NewHydroDam)\end{aligned} \qquad \forall t \in T \tag{3.17}$$

$$\mathbf{Sto_{in}}(PumpedHydro, Elec, t) \leq f_{\max}(pumps) \qquad \forall t \in T \tag{3.18}$$

3.3.3 Implementation of long term storage technologies

The MILP model from [34] includes technologies for the production of H_2 and SNG. However it does not offer the possibility to store H_2 and SNG, hence production needs to meet demand in every time step. To avoid this constraint, we have integrated H_2 and SNG storage technologies in the new version of the model. The same approach used for the implementation of the P2G technology is used. The H_2 storage option is composed of three technologies:

- Technology compressing H_2 from 1 bar to 875 bar. The electricity consumption for the compression is 0.0798 MJ_{elec}/MJ_{H2} [200]. The cost of the compressor is 57.39 CHF_{2015}/kW_{H2} [200]. The operation and maintenance cost of the compressor is 4% of the investment [200]. The life time of the compression unit is 10 years.
- Technology for the expansion of the H_2. No energy consumption or cost is attributed to the expansion technology, since they are considered trivial in comparison of those for the other two technologies.
- Technology storing the compressed H_2. The cost of the storage system is based on the cost of type 2 vessels in [200]: 21.48 CHF_{2015}/kWh_{H2}. Its life time is 30 years.

Like the H_2 storage, the NG storage is composed of three technologies:

- Liquefaction technology. The liquefaction technology consums 1.019 units of natural gas to produce 1 unit of LNG (98% efficiency) [201].
- Gasification technology, which has no cost and energy consumption associated, since they are considered trivial in comparison of those for the other two technologies.
- Storage technology, which consists a large industrial concrete tank.

The cost of the liquefaction train and the concrete storage tank for the LNG is the same as for the P2G technology reported in appendix A.

3.3.4 Implementation of smart charging

Electric vehicles, both BEVs and PHEVs, are a technology that can be used for DSM actions to balance the electricity grid if they are "smartly" charged. They offer also the possibility of implementation of V2G strategies, nonetheless that option is not implemented in the model. The current implementation consists on offering demand response services through smart charging. Only private cars are considered for this option. The decision to exclude the other types of EV (e.g. bus, coach, lorry, etc) is based on the lack of data for defining their driving profiles.

The implementation is based on the introduction of a set of typical cars, called CARS. Each typical car i has a usage profile *carProfile(i,t)*. This parameter provides the fraction of the annual electricity consumption of electric cars (BEV and PHEV) ($\mathbf{Elec_{BEV\&PHEV}}$ in Eq. 3.19) attributed to the car i in the period t, which indicates if the car is being driven (*carProfile(i,t)* ≥ 0) or parked (*carProfile(i,t)* $= 0$). It is assumed that when the car is parked, it is available for being smartly charged. This assumption implies that all households, an driving destinations (offices, industrial site, shopping centers) will have to be equipped with charging stations. Such an intensive deployment of infrastructure could be compared to the one that has already done for the natural gas grid or the optic fiber.

The energy consumption of the cars is considered to be proportional to the driving time, hence the driving speed is constant. The purpose of the typical cars is to generate a new electricity demand profile. Their *f(i,Elec)* is equal to 1, while for all the other layers is equal to 0. This implies that $\mathbf{F_t}$(i,t) of a typical car is equal to its electricity consumption at period t (Eq.3.20).

In order to cover the electricity demand from CARS, a set of batteries is introduced (CAR BATTERIES), which are defined as storage technologies in the model. Eq. (3.23-3.24) impose that the batteries can only provide electricity to their respective CARS. The parameter *BatCar(i,j)* is equal to one when the battery index *i* and the car index *j* correspond to the same typical car.

The model in [34] considers the usage profile of the cars to be constant across all periods. Eq. (3.21-3.22) are used to neutralise the calculation of the electricity consumption of BEV and PHEV cars based on the formulation from [34]. $AuxCar_{BEV}$ and $AuxCar_{PHEV}$ have f(i,Elec) opposite to Car_{BEV} and Car_{PHEV}, respectively. This avoids the double counting of the electricity consumption of the cars, since Eq. 3.20 adds the additional electricity demand calculated from the *carProfile(i,t)*. At the same time, *f(i,l)* for all the other layers is equal to zero for the two auxiliary cars, they do not have any effect on the other layers.

Finally Eq. 3.25 warranties that the charging power in the instant t is not superior to the charging installed capacity $f_{charging}$(i) for the typical car i.

$$\sum_{t \in PERIODS}(f(Car_{\mathrm{BEV}}, Elec)\mathbf{F_t}(Car_{\mathrm{BEV}}, t) + f(Car_{\mathrm{BEV}}, Elec)\mathbf{F_t}(Car_{\mathrm{PHEV}}, t)) = \mathbf{Elec_{BEV\&PHEV}} \qquad \forall t \in T \quad (3.19)$$

$$\mathbf{F_t}(i,t) = \mathit{carProfile(i,t)}\mathbf{Elec_{BEV\&PHEV}} \qquad \forall i \in CARS, \forall t \in T \quad (3.20)$$

$$\mathbf{F_t}(Car_{\mathrm{BEV}}, t) = \mathbf{F_t}(AuxCar_{\mathrm{BEV}}, t) \qquad \forall t \in T \quad (3.21)$$

$$\mathbf{F_t}(Car_{\mathrm{PHEV}}, t) = \mathbf{F_t}(AuxCar_{\mathrm{PHEV}}, t) \qquad \forall t \in T \quad (3.22)$$

$$\mathbf{Sto_{out}}(i, Elec, t) \geq BatCar(i,j)\mathbf{F_t}(j,t) \qquad \forall i \in \mathit{CAR\ BATTERIES}, \forall j \in \mathit{CAR}, \forall t \in T \quad (3.23)$$

$$BatCar(i,j)\mathbf{Sto_{out}}(i, Elec, t) \leq \mathbf{F_t}(j,t) \qquad \forall i \in \mathit{CAR\ BATTERIES}, \forall j \in \mathit{CAR}, \forall t \in T \quad (3.24)$$

$$\mathbf{Sto_{in}}(i, Elec, t) \leq f_{charging}(i) \qquad \forall i \in \mathit{CAR\ BATTERIES}, \forall t \in T \quad (3.25)$$

3.3.5 Implementation of thermal storage in buildings

In this model, we have applied the thermal storage to only decentralised technologies for heat supply in buildings, which consume or supply electricity, i.e. CHP, HP and direct electric heating (DEH). That is explained by the fact that the goal of the thermal storage is to provide flexibility on the operation of those technologies in order to integrate the renewable electricity production. The technologies having the thermal storage option are part of the new DEC set. For each of the technologies in DEC, three auxiliary technologies are added into the model:

- A first one have its input from and output to the electricity layer (*f(i,Elec)*) opposite to the heating technology in DEC. In this way the effect of the technology in the electricity layer is reduced or deleted, which represent a reduction on the use of the heating technology in the period *t*. All technologies playing this role are grouped in the DEC DEL set.
- A second technology has *f(i,Elec)* equal to its heating technology in DEC, and it will be employed in the period where the use of the heating technology is displaced to. This second technology is part of the DEC ADD set.
- A third auxiliary technology corresponds to a storage technology, which stores heating demand for its corresponding heating technology. The thermal storage technology is connected to a specific layer for thermal storage (*ThSto*), which is shared by all the thermal storage technologies. It belongs to the TH STO set.

The behaviour of these three new auxiliary technologies is illustrated in Figure 3.1. In addition two auxiliary technologies connected to *ThSto* are added. Their purpose is to allow to close the balance imposed by Eq. 3.8 for the *ThSto*.

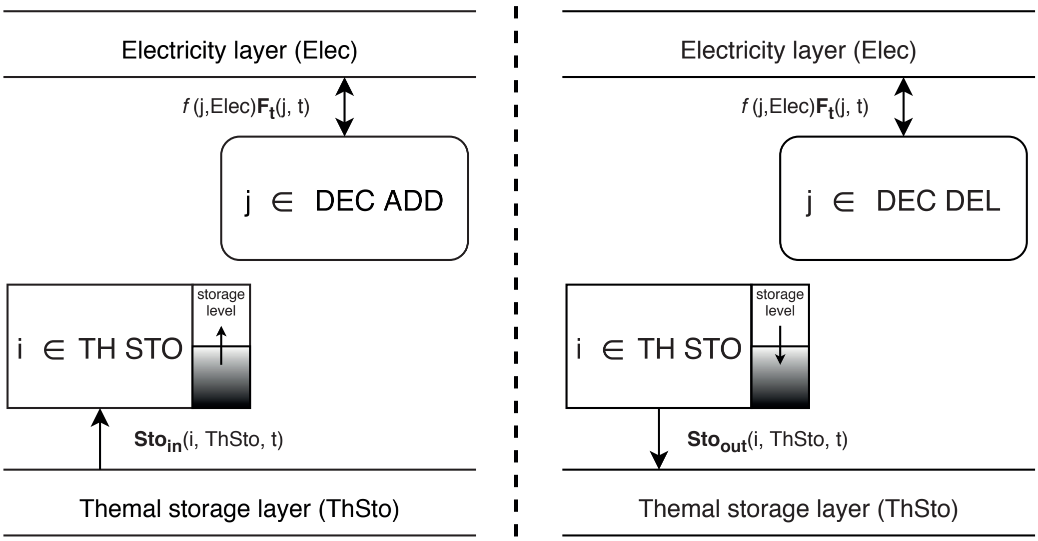

Figure 3.1 – Behaviour of the three auxiliary technologies. Left side: It represents an increase on the operation of one of the technologies in DEC. Hence the electricity consumption (if HP or DEH) or supply (if CHP) of the technology in DEC is increased by its corresponding technology in DEC ADD. Also the thermal storage level of its corresponding technology in TH STO is increased, since there is no existing heat demand for the supplementary heat production. Right side: It represents a decrease on the operation of one of the technologies in DEC. Hence the electricity consumption or supply of the technology in DEC is reduced by its corresponding technology in DEC DEL. The the thermal storage level of the corresponding technology in TH STO is decreased, since the heat demand has to be covered. The coordination in the operation of the technologies in DEC ADD and DEC DEL with those in TH STO is warrantied by Eq. 3.26-3.29.

Eq. (3.26,3.27) link the usage of the technologies in the DEC DEL set with the use of their respective thermal storage technologies. When a technology in the DEC DEL set is used, the corresponding thermal storage technology in TH STO is supposed to cover the heating demand. Eq. (3.28,3.29) has the same purpose like Eq. (3.26,3.27), but in this case it relates a technology in ADD DEL with its corresponding technology in TH STO.

$$\mathbf{Sto_{out}}(i, ThSto, t) \geq StoD(i,j)\mathbf{F_t}(j,t) \qquad \forall i \in TH\,STO, \forall j \in DEC\,DEL, \forall t \in T \quad (3.26)$$

$$StoD(i,j)\mathbf{Sto_{out}}(i, ThSto, t) \leq \mathbf{F_t}(j,t) \qquad \forall i \in TH\,STO, \forall j \in DEC\,DEL, \forall t \in T \quad (3.27)$$

$$\mathbf{Sto_{in}}(i, ThSto, t) \geq StoA(i,j)\mathbf{F_t}(j,t) \qquad \forall i \in TH\,STO, \forall j \in DEC\,ADD, \forall t \in T \quad (3.28)$$

$$StoA(i,j)\mathbf{Sto_{in}}(i, ThSto, t) \leq \mathbf{F_t}(j,t) \qquad \forall i \in TH\,STO, \forall j \in DEC\,ADD, \forall t \in T \quad (3.29)$$

Eq. 3.30 warranties that the reduction imposed by the auxiliary boilers (see section 3.3.1) and the thermal storage option on the use of a technology in DEC is not higher than its $\mathbf{F_t}$. Eq. 3.30 is not used for Dec_{HP} and $Dec_{DirectElec}$ since these two technologies do not have auxiliary boilers. Eq. 3.31 is equivalent to Eq. 3.30 but it does not take into consideration the reduction from the auxiliary boilers, hence it is used for Dec_{HP} and $Dec_{DirectElec}$.

$$DecDel(i,j)(\mathbf{F_t}(j,t) + \sum_{k \in AUX\,REPLACED} \mathbf{F_t}(k,t)) \leq \mathbf{F_t}(i,t)$$
$$l \in \{Dec_{\mathrm{HP}}, Dec_{\mathrm{DirectElec}}\}, \forall i \in DEC \setminus \{l\}, \forall j \in DEC\,DEL, \forall t \in T \quad (3.30)$$

$$DecDel(i,j)\mathbf{F_t}(j,t) \leq \mathbf{F_t}(i,t)$$
$$\forall i \in \{Dec_{\mathrm{HP}}, Dec_{\mathrm{DirectElec}}\}, \forall j \in \{Del_{\mathrm{HP}}, Del_{\mathrm{DirectElec}}\}, \forall t \in T \quad (3.31)$$

Eq. 3.32 makes the sum of the $\mathbf{F_t}$ of technology in the ADD set and its corresponding technology in the DEC set, not to be higher than its installed power ($\mathbf{F}$).

$$DecAdd(i,j)(\mathbf{F_t}(i,t) + \mathbf{F_t}(j,t)) \leq \mathbf{F}(i) \qquad \forall i \in DEC, \forall j \in DEC\,ADD, \forall t \in T \quad (3.32)$$

From Eq. 3.26 to Eq. 3.32 four different parameters (*StoD, StoA, DecDel* and *DecAdd*) are used for activating the constraints when there is the right index combination. For example the *StoD(i,j)* parameter is used to activate the constraints when the technologies *i* and *j* are auxiliary technologies of a same decentralized technology, e.g. $StoD(ThStorage_{HP},Dec_{HP})$ is equal to 1, while $StoD(ThStorage_{HP},Dec_{DirectElec})$ is equal to 0.

3.4 Definition of the thermal storage potential based on the deployment of MPC systems in Switzerland

In this section we present a methodology for the definition of the thermal storage potential in Switzerland from the results that Stadler et al. obtained when they analysed the deployment of model predictive control (MPC) systems for energy systems in buildings. The results and the methodology that Stadler et al. employed are discussed in [202].

3.4.1 Available results of the deployment of MPC systems in Switzerland

The energy system of a building can be composed of several technologies: boiler, HP, PV panels, thermal storage tank, etc. MPC systems optimize the building energy system operation strategy, taking into consideration parameters such as temperature and radiation forecast, or expected electricity prices. Stadler et al. [202] propose a MILP formulation to reproduce the MPC problem. The developed formulation describes the thermo-economic behavior of a building energy system allowing the optimisation of its design (CAPEX) and OPEX. It offers a third optimisation objective, the pseudo generation multiple (GM). The GM grades the level of grid-friendliness of the solution. The formulation of the GM indicator is available in [203]. It evaluates the smoothness of the interaction between the building and the electricity grid, since it compares the daily absolute net grid-building power flow to its daily average.

In [202], Stadler et al. explore the potential of MPC for building energy systems in Switzerland. For that purpose data on the Swiss building stock is required. As mentioned in section 3.5, this information is obtained from the RegBL database [204]. In Switzerland, the buildings stock contains 1.7 millions elements by ends 2016 [205], hence it is not feasible to solve the problem for each of the buildings due to a lack of data and calculation time constraints. Stadler et al. classifies the buildings by their type (single family, multi-family and mixed-usage) and by their age category.

In addition, they apply a dual spatial and temporal clustering. The data to perform the clustering comes from weather data from 40 national weather stations. Prior to the clustering a design reference year (DRY) is calculated [206]. The spatial clustering reduces the number of weather stations to eight. The temporal clustering decomposes the DRY into 6 typical days plus 2 extreme peak periods to capture the peak demand hours. Hence the methodology presented in [202] calculates the Swiss potential of MPC by solving the 120 optimisation problems obtained when the options of each of the columns in table 3.3 are combined.

Table 3.3 – Combinations of elements classifying the buildings.

Buidlings type	Weather station	Construction period
Single family	Genève-Cointrin	1920
Multi-family	La Chaux-de-Fonds	1970
Mixed-usage	Lugano	1980
	Ulrichen	2005
	Zürich-SMA	2020
	Montana	
	Bern-Liebefeld	
	Davos	

For each of the building type / weather stations / construction period (BWC) combination 15 solutions are generated. The fifteen solutions correspond to the combination five possible upper limits for the CAPEX with three possible upper limits for the GM. each of the solutions defines the mix of installed technologies and their operations strategy for each of the typical days.

3.4.2 Integration of the results into the model for determining the thermal storage potential

The results Stadler et al. obtained from the analysis of the implementation of MPC systems serve as basis to define the thermal storage potential of the building stock in Switzerland. each of the 15 generated solutions for each BWC combination has a space heating profile determined by the optimiser. The optmised profile respects the imposed indoors temperature bounds (15°C ≤ T_{in} ≤ 30°C). The building thermal behaviour, i.e. the space heating demand ($\mathbf{Q_{Sh}}$(t) [kW]), is calculated with a first-order resistance-capacity model [202], which is described in Eq. 3.33, whose parameters are listed in table 3.4. The HOURS set contains the hours of each typical day. The time duration of the time steps (t_{op}) is one hour, measured in hours.

Table 3.4 – Parameter list with description from Eq. 3.33. The parameters are specific to each type of building.

Parameter	Units	Description
U	[kW/(°C·m^2)]	Building heat transfer coefficient.
C	[kWh/(°C·m^2)]	Building heat capacity coefficient.
A	[m^2]	Building reference area.
$Q^{+}{}_{Gains}$(t)	[kW]	Heat gains from the building usage (e.g. users and appliances).
$Q^{+}{}_{Solar}$(t)	[kW]	Heat gains from solar radiation.

$$\mathbf{Q_{Sh}}(t) = \frac{-e^{-t_{op}*U/C}\mathbf{T_{in}}(t) - (1 - e^{-t_{op}*U/C})\,T_{\text{ext}}(t) + \mathbf{T_{in}}(t+1)}{1 - e^{-t_{op}*U/C}}(U * A) - Q^{+}{}_{\text{Gains}}(t) - Q^{+}{}_{\text{Solar}}(t)$$

$$\forall t \in HOURS \quad (3.33)$$

In addition to the 15 optimized space heating profiles for each BWC combination generated by Stadler et al., we calculate a 16$^{\text{th}}$ profile considering that the heating is controlled by a thermostat at 20°C, hence $\mathbf{T_{in}}$(t) is constant at 20°C. The comparison between the optimized and the thermostat-controlled heating profiles gives the thermal storage capacity for each BWC combination and for each typical day. The thermal storage capacity is calculated as the maximum accumulated heat supply difference between the two profiles.

For the implementation of the thermal storage for buildings in the national energy system (NES) model is necessary to have an annual hourly profile for the thermal storage capacity. However at this point of the methodology, we only have the hourly profile for the thermal storage capacity for the 6 typical days. In order to obtain an annual hourly profile (c) is necessary to find the best fitting typical day for each 24-hours period in the representative year used in the NES model. The selection is done based on the comparison of the outdoors daily average temperature for each of the weather stations.

The 20°C profile is also used to obtain the annual specific SH demand ($\bar{q}_{Annual}$) of the BWC combination for the design reference year (DRY) used for the MPC calculations. For computing it, we take into consideration the frequency of each of the typical days in the DRY.

At this step of the methodology we know the thermal storage capacity for each of the solutions for each BWC combination. However the researched value is the Swiss thermal storage capacity offered by the building stock. Hence we need to be able to describe the future building stock as a combination of the solutions. Thus the next step consists in determining the square meters for each of the solutions in the future Swiss building stock. The square meters mix problem is added into the MILP formulation describing the NES. The daily national thermal storage capacity **C** is calculated using the square meters mix in Eq. 3.34.

Eq. 3.35 and 3.36 warranty that the square meter mix respects the mix of technologies defined at national level. The TECHS THS set contains the technologies that are considered to generate the MPC solutions: HPs, CHP, boiler and DEH. Eq. 3.37 ensures that the new area mix respects the expected increase in surface for each of the building types. That increase can only come from buildings with 2005 and 2010 contruction characteristics (Eq. 3.38), and the surface for buildings with 2020 standards cannot decrease (Eq. 3.39). Furthermore, the new surface mix must compile with the expected increase in buildings insolation (Eq. 3.40).

All parameter and variables from Eq. 3.34 to Eq. 3.40 are listed and explained in tables 3.5 and 3.6

with their corresponding description.

Table 3.5 – Parameter list with description.

Parameter	**Units**	**Description**
p_{th}(b,c,w,s,tech)	[kW/m^2]	Technology specific thermal installed capacity for solution *s* in the b,c,w combination.
$\bar{q}_{Annual}$(b,c,w,s)	[kWh/m^2]	Specific annual SH demand the b,c,w combination in reference year.
ΔQ	[-]	Decrease of the annual national buildings heating demand relative to the old surface heating demand.
S_{refOld}(b,c,w)	[m^2]	Current square meters for the b,c,w combination.
ΔS(b)	[-]	Increase of the surface for building type *b* relative to the old surface S_{refOld}.
c(b,c,w,s,t)	[kWh/m^2]	Daily thermal storage capacity for solution *s* in the b,c,w combination.

Table 3.6 – Variables list with description.

Variable	**Units**	**Description**
$\mathbf{S_{refNew}}$(b,c,w,s)	[m^2]	New square meters for solution *s* in the b,c,w combination.
$\mathbf{Q^{+}}_{\mathbf{Total}}$	[kW]	Total installed thermal power.
$\mathbf{C}$(t)	[kWh]	Daily total thermal storage capacity.
$\mathbf{\%_{DecMix}}$(tech)	[-]	Ratio [0;1] *tech* installed capacity over total installed capacity.

$$\mathbf{C}(t) = (1 - \mathbf{\%_{Dhn}}) \sum_{i \in TYPE, j \in METEO, k \in YEAR, l \in SOLUTION} c(i,j,k,l,t)\mathbf{S_{refNew}}(i,j,k,l) \qquad \forall t \in T \quad (3.34)$$

$$\mathbf{Q^{+}}_{\mathbf{Total}} = \sum_{i \in TYPE, j \in METEO, k \in YEAR, l \in SOLUTION, m \in TECHS\ THS} p_{th}(i,j,k,l,m)\mathbf{S_{refNew}}(i,j,k) \quad (3.35)$$

$$\mathbf{\%_{DecMix}}(tech)\mathbf{Q^{+}}_{\mathbf{Total}} \geq \sum_{i \in TYPE, j \in METEO, k \in YEAR, l \in SOLUTION} p_{th}(i,j,k,l,m)\mathbf{S_{refNew}}(i,j,k,l) \qquad \forall m \in TECHS\ THS \quad (3.36)$$

$$\sum_{k \in YEAR} \Delta S(i) S_{refOld}(i,j,k) = \sum_{k \in YEAR, l \in SOLUTION} \mathbf{S_{refNew}}(i,j,k,l) \qquad \forall i \in TYPE, \forall j \in METEO \quad (3.37)$$

$$S_{refOld}(i,j,k) \leq \sum_{l \in SOLUTION} \mathbf{S_{refNew}}(i,j,k,l)$$

$$\forall i \in TYPE, \forall j \in METEO, \forall k \in YEAR \setminus \{2005, 2020\} \quad (3.38)$$

$$S_{refOld}(i,j,2020) \leq \sum_{l \in SOLUTION} \mathbf{S_{refNew}}(i,j,2020,l) \qquad \forall i \in TYPE, \forall j \in METEO \quad (3.39)$$

$$\sum_{i\in TYPE, j\in METEO, k\in YEAR} S_{refOld}(i,j,k)\bar{q}_{Annual}(i,j,k,16) \geq \sum_{i\in TYPE, j\in METEO, k\in YEAR, l\in SOLUTION} \bar{q}_{Annual}(i,j,k,l)\mathbf{S_{refNew}}(i,j,k,l) \tag{3.40}$$

3.5 Calculation of the hourly electricity demand for heating at national level

We have developed a methodology to calculate the fraction of the electricity consumption related to space heating in the current national electricity demand profile. In order to present this methodology, we have to introduce the concept of equivalent hours and equivalent days. Hours are equivalent if they are the same hour of equivalent days. Days to be equivalent have to belong to different years and to be part of the same day of the week and the days they belong to have to be not further than three calendar days. This two conditions aim at reducing the sources of variability not related to the temperature. The “same day of the week” condition is explained by the fact that each day of the week has a particular profile, specially Friday, Saturday and Sunday. The condition limiting the distance in terms of calendar days reduces the variability from factors like the change in day light. An additional condition is that none of the days must be holidays. Holidays are excluded since they present a particular demand profile in comparison with the other same days of the week.

Table 3.7 contains examples of equivalent and non-equivalent days for three consecutive years. For instance, Monday 05/01/09, Monday 04/01/10 and Monday 03/01/11 are equivalent days because they are the same day of the week, the maximum distance in terms of calendar days among them is 2 and non of them are holidays.

Table 3.7 – Example of equivalent and non-equivalent days.

Day of the Week	**Year**						**Equiv. day**
	y_1		**y_2**		**y_3**		
	Date	Holiday	Date	Holiday	Date	Holiday	
Thursday	01/01/09	Y	-	-	-	-	N
Friday	02/01/09	Y	01/01/10	Y	-	-	N
Saturday	03/01/09	N	02/01/10	Y	01/01/11	Y	N
Sunday	04/01/09	N	03/01/10	N	02/01/11	Y	N
Monday	05/01/09	N	04/01/10	N	03/01/11	N	Y
Tuesday	06/01/09	N	05/01/10	N	04/01/11	N	Y

The methodology is based on the assumption that the difference between the national electricity demand of equivalent hours can be partially explained by the difference of exterior temperatures, which creates different electricity demands for space heating. Hence the difference between the national electricity demand (**$\mathbf{Diff_{Data}}$**) is correlated to the difference between the electricity consumption for space heating (**$\mathbf{Diff_{Calc}}$**), when these differences are calculated for equivalent hours. This assumption is used to find a function linking the electricity demand for space heating to the outdoors temperature at national level. Figure 3.2 supports the assumption, since it can be appreciated an existing correlation between the Swiss electricity demand difference and the Swiss average temperature difference for equivalent hours.

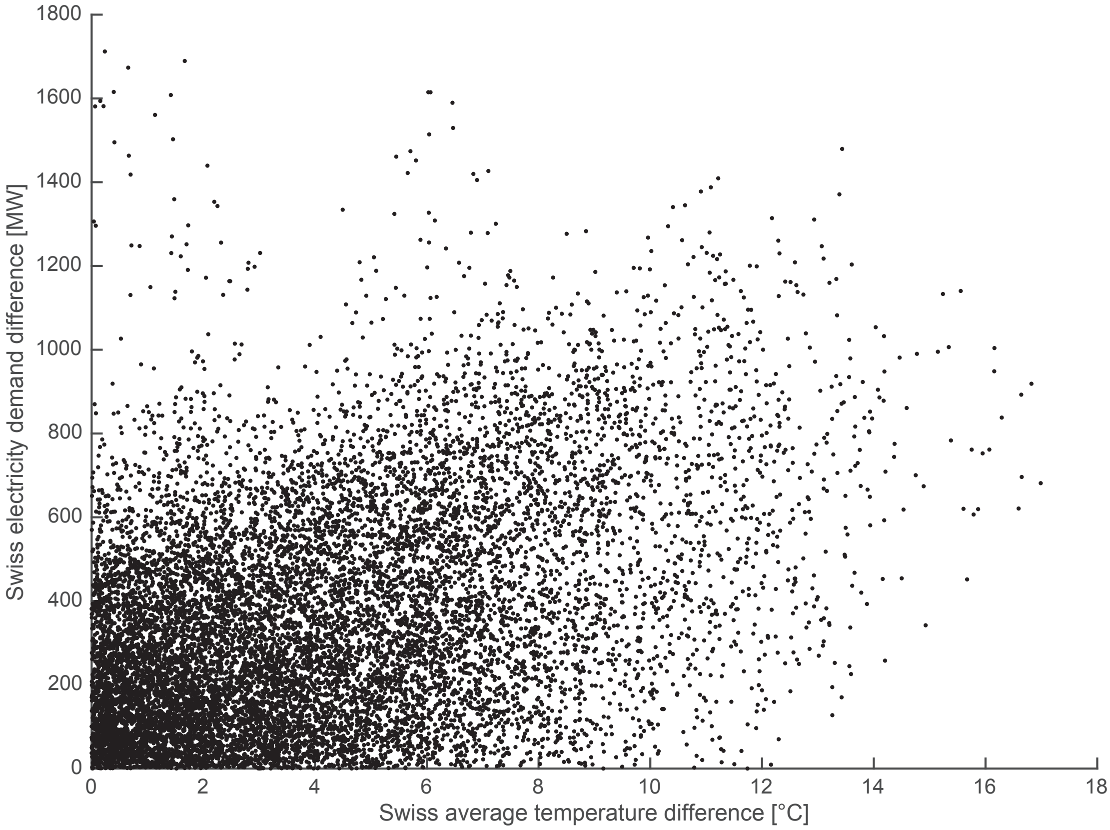

Figure 3.2 – Swiss electricity demand differences between equivalent hours for they years 2009, 2010 and 2011, against the Swiss average temperature differences between the same equivalent hours.

In this methodology, the electricity demand for heating is calculated using a linear model of the power requirement as a function of the exterior temperature (T_{ext}), multiplied by a correction factor $\mathbf{f_c}(d,h_d)$. The linear model is known as heating signature [207]. The power requirement is equal to zero when T_{ext} is lower than the set temperature ($\mathbf{T_0}$). The factor $\mathbf{f_c}(d,h_d)$ corrects the power demand calculated from the first degree linear function. Its goal is to capture the effect of the other heat sources, such as building occupants or solar gains. The variable **shift** takes into consideration the thermic inertia of the building. This variables captures the fact that a change in the outside temperature may not be immediately translated into a change in the heating power. The minimization of the sum of differences of differences ($\mathbf{Diff_{Diff}}$) over all equivalent hours (Eq. 3.41) for three different years (y_1, y_2, y_3) is used to find the values for the variables or unknown parameters in Eq. 3.45 ($\mathbf{f_c}$*(d,h_d)*,$\mathbf{h_0}$,$\mathbf{h_1}$,**shift**) which results in a mixed non-linear integer programming (MNILP) problem. $\mathbf{f_c}$, *(d,h_d)*, $\mathbf{h_0}$ are continous variables without any upper or lower boundary, while **shift** is an integer variable with 0 and 3 as lower and upper bound.

Eq. (3.42 - 3.44) are necessary to calculate the difference of differences. *$Power_{Total}$(i,h)* is the total national electricity demand for the year *i* and the equivalent hour *h*. The set H contains the equivalent hours. When comparing the years 2009, 2010 and 2011 for Switzerland (considering Swiss holiday days), there are 4415 equivalent hours. The set $\mathrm{H_d}$ reassembles the hours of the day (from 1 to 24h).

$$\min \sum_{h\in H} (\mathbf{Diff_{Diff}}(y_1, y_2, h) + \mathbf{Diff_{Diff}}(y_2, y_3, h) + \mathbf{Diff_{Diff}}(y_1, y_3, h)) \tag{3.41}$$

$$\text{s.t. } \mathbf{Diff_{Diff}}(i, j, h) = \left|\mathbf{Diff_{Calc}}(i, j, h) - \mathbf{Diff_{Data}}(i, j, h)\right| \qquad \forall i, j \in \{y_1, y_2, y_3\}, \forall h \in H \tag{3.42}$$

$$\mathbf{Diff_{Calc}}(i, j, h) = \left|\mathbf{Power_{Sh}}(i, h) - \mathbf{Power_{Sh}}(j, h)\right| \qquad \forall i, j \in \{y_1, y_2, y_3\}, \forall h \in H \tag{3.43}$$

$$\mathbf{Diff_{Data}}(i, j, h) = \left|Power_{\mathrm{Total}}(i, h) - Power_{\mathrm{Total}}(j, h)\right| \qquad \forall i, j \in \{y_1, y_2, y_3\}, \forall h \in H \tag{3.44}$$

$$\mathbf{Power_{Sh}}(i, h) = \left\lceil_{T_{\mathrm{ext}}(i,h+\mathbf{shift})\geq \mathbf{T_0}} \mathbf{f_c}(d, h_d)(\mathbf{h_0} + \mathbf{h_1}\, T_{\mathrm{ext}}(i, h + \mathbf{shift}))\right\rceil + \left\lceil_{T_{\mathrm{ext}}(i,h+\mathbf{shift})<\mathbf{T_0}} 0\right\rceil$$
$$\forall d \in \{week, sat, sun\}, \forall i \in \{y_1, y_2, y_3\}, \forall h_d \in H_d, \forall h \in H \tag{3.45}$$

The proposed methodology has been tested with data for Switzerland for the years 2009, 2010 and 2011. The Swiss electricity demand is obtained from [208]. The Swiss outdoors temperature is calculated as the weighted average of the outdoors temperature measured in eight weather stations obtained from the Swiss weather database (IDAWEB) [10]. The selected weather stations correspond to the eight spatial cluster calculated in [202]. The weight of each of the stations in the Swiss average is calculated following Eq. 3.46, where *S_{ref}(j)* and *h(j)* are the reference surface and the heat transfer coefficient of the building *j*. The set $\mathrm{N_b}$(i) contains the buildings for the cluster*i*, which is part of the set $\mathrm{N_c}$. The information on the Swiss building stock is obtained from the RegBL database [204]. It contains information regarding the construction period of the buildings, while the age-dependent heat transfer coefficients of the building envelope are available in [209].

$$weight(i) = \frac{\sum_{j\in N_{\mathrm{b}}(i)} S_{\mathrm{ref}}(j)h(j)}{\sum_{i\in N_{\mathrm{c}}} \sum_{j\in N_{\mathrm{b}}(i)} S_{\mathrm{ref}}(j)h(j)} \qquad \forall i \in N_{\mathrm{c}} \tag{3.46}$$

The obtained parameters for the heating signature and the correction factors are available in appendix D.2. Using the heating signature function ($\mathbf{Power_{Sh}(i,h)}$) with the parameters from appendix D.2, the annual consumption of electricity for space heating in Switzerland is evaluated at 5005 GWh for the year 2011. In the statistics from the SFOE, the reported electricity consumption for space heating in 2011 is 4596 GWh [210]. The relative difference between the two figures is 8.9 %.

3.6 Integrating intermittent renewable electricity in Switzerland in 2035

The model described in section 3.3 is applied in a case study for Switzerland. The goal of the case study is to test the developed model while analysing the behaviour of the combination of power-to-heat (P2H) and CHP with thermal storage for buildings, smart charging in electric vehicles (EVs), and long-term energy storage technologies. The case study is based on the New Energy Policies (NEP) scenario from the Swiss Federal Office of Energy (SFOE) in 2035 [12]. The NEP scenario considers that by 2035 there will be no electricity from nuclear origin. Despite being the most optimistic scenario in terms of renewables deployment and energy efficiency of the three scenarios contemplated by the SFOE [12], there are only 4 months per year in which indigenous electricity is enough to cover the demand. On an annual basis, only about 70% of the demand is covered with electricity from renewable, 15% with imported electricity and the remaining 15% corresponds to electricity supplied by CHP systems. A detailed description of the scenario is available online in the Swiss-energyscope calculator [156] or at [12].

3.6.1 Calculation of the energy supply and demand profiles for Switzerland

The realisation of the case study requires annual hourly profiles for the renewable energy production and the weather conditions. The profiles are calculated for a design reference year (DRY). The DRY is meant to provide the profiles for a representative year of a long-term period, e.g. a decade. The methodology followed for the calculation of the DRY is detailed in appendix D.1.

Weather data

The weather data (global radiation and air temperature measured 2m above ground) are obtained from the IDAWEB service provided by MeteoSwiss [10]. The measurements come from the 8 weather stations listed in table 3.3 for the years 2009-2015. The Swiss outdoors temperature is calculated as already described in section 3.5. The Swiss global radiation is calculated also through a weighted average of the data from the 8 weather stations. Since the radiation data is used for computing the Swiss PV electricity production profile, the weight of each station is only directly proportional to the sum of the buildings footprint. It is calculated in this way since it is assumed that PV panels will only be placed on roofs. Building footprint data is available in the RegBL database [204].

Electricity and space heating demand

The national electricity demand is obtained from [208]. Once the DRY is calculated, the demand related to electric SH (DEH and HPs) is removed. The SH related electricity consumption is computed with the methodology introduced in section 3.5, taking into consideration the exterior temperature for the DRY. The demand for SH ($\%_{sh}$ *in [34]* is assumed to follow the same profile like the demand related to electric SH.

Hydro dams

There is no data source available giving the water inflows into the Swiss dams. On the other hand the electricity production, the electricity consumption of the pumps for pumping storage and the level of the dams can be obtained from [211] for every week aggregated at Swiss level. To obtain hourly values, the weekly data is interpolated. The water inflow of the Swiss dams ($\mathbf{E_{inflow}}$) is calculated with Eq. 3.47, where $\mathbf{E_{turbine}}$ and $\mathbf{E_{pump}}$ are the electricity produced by the turbines and the electricity consumed by the pumps, respectively. Δ**Level** is the change in level of the electricity stored in the dams.

$$\mathbf{E_{inflow}}(t) = \Delta\mathbf{Level}(t) + \mathbf{E_{turbine}}(t) - \mathbf{E_{pump}}(t) \tag{3.47}$$

Wind electricity

In order to calculate the Swiss capacity factor for wind turbines, 18 new locations for wind parks are considered (see Appendix D.3). The wind park are part of the feasible locations considered in [15]. each of the locations is attributed to nearest MeteoSwiss weather stations for having access to wind speed data. This reduces the number of weather stations to 11. At the weather stations the speed is mesured at 10 m above ground level, then the wind speed is calculated at 50 m height using the conversion factors in table D.4. The power-speed curve of a Gamesa G128-4.5 MW wind turbine [212] is used to obtain the capacity factor profiles for each of the considered locations. The last step consists on solving the combinatorial problem that provides the weight of each of the weather station for the calculation of the Swiss wind turbine capacity factor, which must be equal to the reported capacity factor in [34]: 0.23.

PV electricity

The calculation of the Swiss PV electricity supply curved is based on the model for a photovoltaic system proposed by A. Ashouri et al. [213]. The model is used to generate the hourly Swiss specific photovoltaic electricity production ($\mathrm{W/m^2}$).The Swiss global radiation and outdoors temperature for the reference year are an inputs to the model. The obtained profile is normalized to its annual average value and multiplied by the expected Swiss PV capacity factor in 2035: 0.113 [34].

Solar thermal

The heat supply profile from thermal solar panels is calculated using the panel efficiency equation in [63]. The parameters used for the efficiency calculation correspond to the flat place solar collector analysed in [214]. A mean temperature in the collector of 50°C is considered. As for the calculation of the capacity factor for PV, the Swiss global radiation and outdoors temperature for the DRY are considered for the calculation of the efficiency, and the subsequent specific thermal power (W/m^2). The profile is then normalized to its maximum thermal power in order to obtain the capacity factor for Switzerland, which is further normalized to its average value and multiplied by the capacity factor reported in [34]: 0.113.

Electric vehicle usage

The characterization of the electric vehicles (EVs) usage profiles is necessary in order to determine the amount of cars available for smart charging, the level of their batteries and their expected electricity consumption at any time of the day. For this case study only private cars are considered. The behaviour of the Swiss cars fleet is modelled with 40 different typical cars. The 40 typical cars are divided by typical usage profile: work, education, shopping and leisure. Each category is represented with 10 cars. In [7], one can obtain the percentage of people on movement (mobile-people) by private car separated by reason for every day. The car usage profiles and their weight in the mobile-people curve are computed aiming to reproduce the mobile-people curves in [7]. Appendix D.4 contains the curves from [7] together with the profiles obtained when combining the 10 typical cars for each driving purpose. In order to obtain specific day mobile-people curve, the mix of mobility reasons for each type of day (Monday-Friday, Saturday and Sunday) are obtained from [7]. In Appendix D.4, the day specific private car mobility curves are compared to the percentage of cars on route for each type of day [8] for validating the generated car usage profiles.

3.6.2 Definition of the evaluated Swiss scenarios

The Swiss case study is composed of 4 scenarios, which are derived from the New Energy Policies (NEP) 2035 scenario. The technology mix in the electricity, heating and transport sector are the same in each one of the 4 new scenarios. Parameters such as population, economic growth or efficiency evolution are also constant across scenarios. The difference between scenarios arise from the strategy to cover the electricity deficit, and the implementation of the thermal storage in buildings, smart charging for electric vehicles (EV) and long-term energy storage.

- Scenario 1: No electricity import is allowed. The electricity deficit must be covered with the further deployment of PV panels. Long-term energy storage, smart charging and thermal storage are available.
- Scenario 2: No electricity import is allowed. The electricity deficit must be covered with the further deployment of PV panels. Long-term energy storage, smart charging and thermal storage are not available.
- Scenario 3: No electricity import is allowed. The electricity deficit must be covered with the further deployment of PV panels. Long-term energy storage is available. Smart charging and thermal storage are not activated.
- Scenario 4: Electricity import is allowed. Long-term energy storage, smart charging and thermal storage are available.

We have used the optimizer to solve the MILP problem of Swiss energy system for each of the scenarios. Since the case study uses the NEP 2035 scenario as basis for the 4 scenarios, the mix of technologies for electricity supply, heat generation and mobility are already defined. Hence the optimiser mainly provides the operation strategy for the national energy system. Nevertheless, there are some installed capacities that have to be determined by the optimiser:

- PV installed capacity. In the scenario where no imports are allowed. The PV installed capacity is defined as variable. Thus the solver finds the optimal amount of installed capacity.
- Storage capacity and conversion capacity for the long-term storage technologies (P2G, H_2 storage and natural gas storage). The P2G is a close-loop electricity storage technology. It corresponds to the seasonal storage technology implemented in the model presented in section 1.4.4, and described in the appendix A.2.
- H_2 production and biomass to synthetic fuel capacities. These are the technologies listed in section 2.6.1 and 2.6.2 in the SI of [34], plus the gasification-methanation of woody biomass combined with electrolyser, presented in appendix B.1.1.
- The mix of new square meters ($\mathbf{S_{refNew}}$). This variable is presented in section 3.4.2.

3.6.3 Analysing and comparing the evaluated Swiss scenarios

Table 3.8 and figure 3.3 display the annual cost of the Swiss energy system for the 4 scenarios. The main conclusion that can be extracted from the results is that under the current set of parameters, the difference between the scenarios with the highest and lowest total annual cost of the energy system is only 2.5%. The most expensive scenario (scenario 2) does not include long-term storage, smart charging and thermal storage. That results on an strong increase of PV installed capacity in comparison to the other scenarios. The cheapest scenario correspond to the only one in which electricity imports are allowed (scenario 4). The difference between scenarios is reduced to 1.5% of the total cost of the energy system, when we compare scenario 4 to the least expensive one without electricity imports, which includes all long-term storage and flexibility options. Thus having an autonomous Switzerland in terms of electricity supply increases the total cost of the energy system by 1.5%.

Table 3.8 – Total annual cost of the energy system.

	Scenario			
	1	2	3	4
PV	620	1121	672	562
Renewable electricity	3561	3561	3561	3561
Heating & CHP	3471	3471	3471	3471
Power to gas	279	0	250	0
H_2 storage & production & imports	75	81	75	65
Infrastructure	4179	4229	4184	4173
Electricity imports	0	0	0	223
Fossil fuels	6654	6569	6634	6490
Wood	891	891	891	891
TOTAL	19729	19923	19737	19436

The only long-term technology with an impact on the total cost is the P2G. Because of the low price of the imported NG, the production of H_2 from NG is has priority over the electrolyser option. Scenario 4 is the only scenario in which H_2 is produced from electricity (see figure 3.8). About 10% of the H_2 consumed in scenario 4 is produced by electrolysers. That is explained by the fact that electricity imports are allowed. In the other three scenarios, the use of the electrolyser for producing H_2 would require an increase on the installed capacity of PV panels, which is not found economically optimal by the optimiser.

In scenario 2, the lack of flexibility options (thermal storage and smart charging), but specially not having the P2G option, brings an increase in the PV installed capacity (8.9 GW in scenario 2, +81% in comparison to scenario 1). Hence the investment and O&M cost on PV is almost doubled when compared to the scenarios 1 and 3. In addition, scenario 2 has the highest infrastructure cost among all scenarios, because of the investment required for reinforcing the grid due to the high PV installed capacity. On the other hand, there is a reduction on the fossil fuel consumption. This is explained by the fact that boilers supply the heating requirements in buildings during summer, since CHP systems would generate excess electricity. In figure 3.6, it can be seen the absence of electricity from decentralised CHP in the summer months. That is possible thanks to model modification explained in section 3.3.1.

Scenario 2 is also characterised by the existence of curtailment. The seasonal component of PV combined with lack of alternatives for long-term storage cause curtailment and electricity exports. The annual level of curtailment of PV and hydro dams are 4.6% and 3.9%, respectively. The rest of renewable electricity technologies present no curtailment. The annual electricity exports amounts

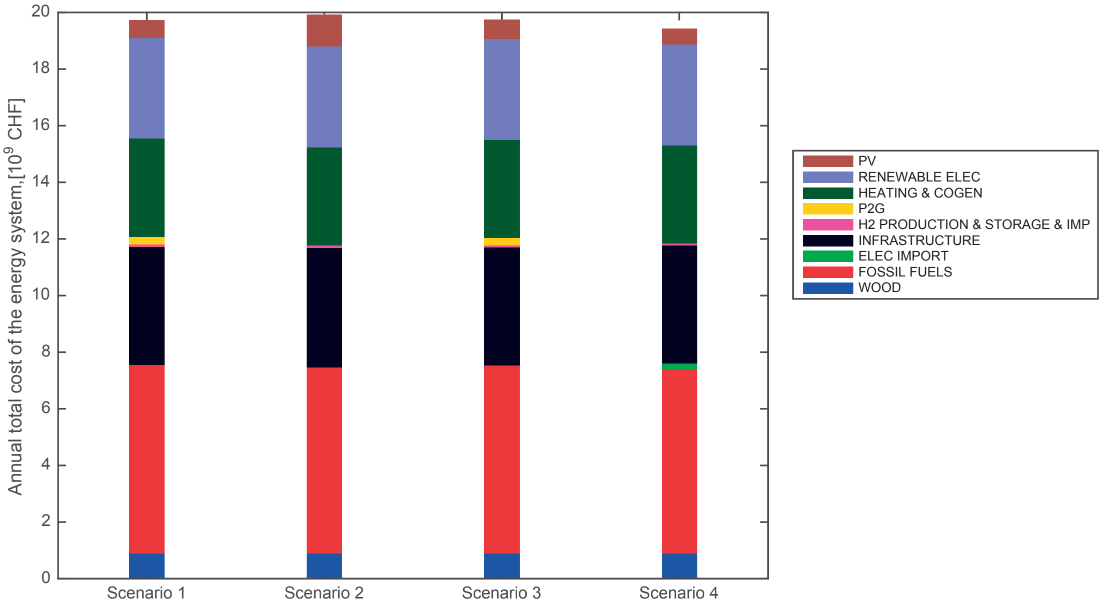

Figure 3.3 – Total annual cost of the energy system for the 4 NEP scenarios. The detailed values of the graph are available in table 3.8.

to 805 GWh. The sum of the curtailed electricity plus the electricity exports is equivalent to the 22.5% of the PV theoretical electricity production, i.e. electricity production including the curtailed production.

The comparison of scenarios 1 and 3 gives a sense of the economic effect of thermal storage and smart charging, which is summarised in the following list:

- PV installed capacity is reduced from 5.3 GW in scenario 3 to 4.9 GW in scenario 1. This brings an annual cost reduction of 52 millions CHF in terms of investment and O&M on PV, plus 5 millions CHF of savings since the electricity grid needs less reinforcement (difference in infrastructure cost).
- The consumption of fossil fuels in scenario 1 is slightly higher in comparison with scenario 3 due to the difference in NG consumption (1675 millions CHF in scenario 1 agains 1655 millions CHF in scenario 2). That is explained by the fact that CHP systems are more used due to their extra flexibility, thanks to the thermal storage.
- The investment and O&M for the P2G is also higher in scenario 1 than in scenario 3. In figure 3.4, it can be seen that the buffer capacity in scenario 1 is 9.9% higher than in scenario 2. Furthermore, the capacity of the conversion technology (electricity-LNG-electricity) is also 11.5% higher, since it can be seen that the slope is steeper.

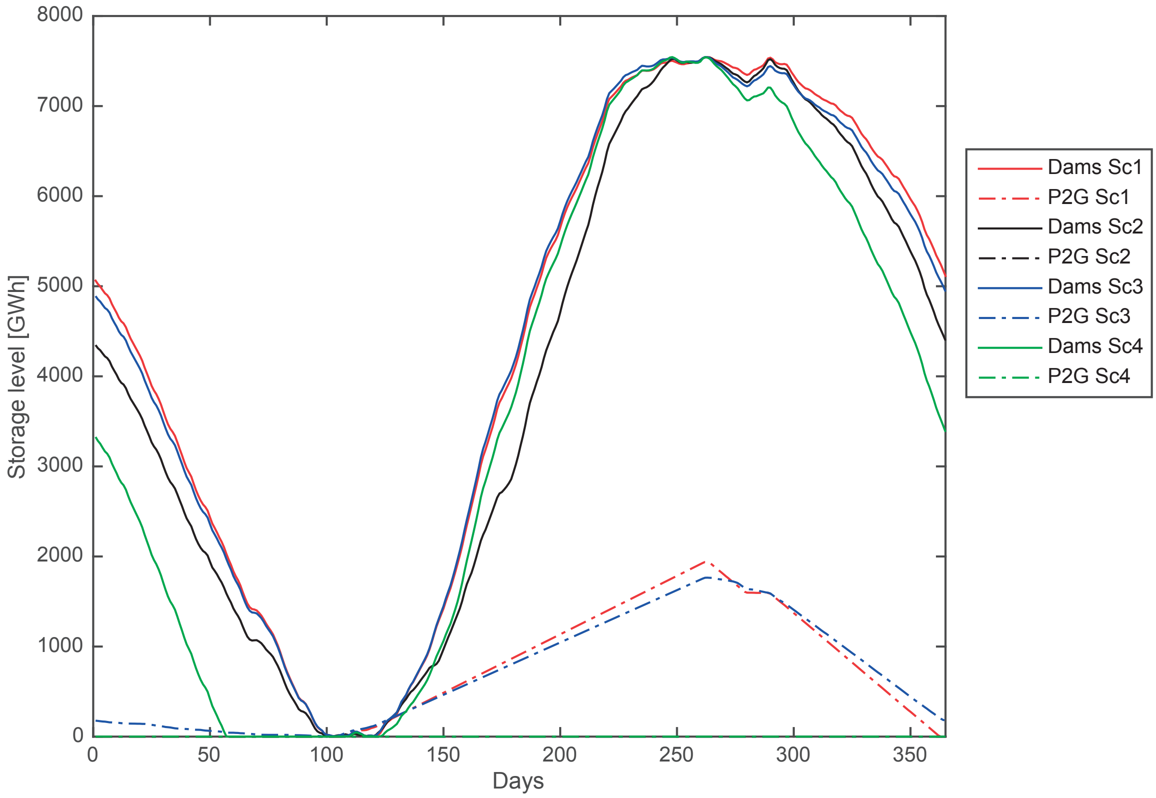

Figure 3.4 – Storage level of the dams and P2G system for the 4 scenarios.

Scenario 2 is the only scenario where the PHS technology is activated by the optimiser (see figure 3.6). Nonetheless, its usage is a result of an arbitrary decision of the optimiser. Due to the 80% round-trip efficiency of hydro pumped technology, it represent a way to dispose of excess electricity in summer, together with the curtailment and the electricity export. Hence the optimiser chooses between those three possibilities, which have no economic cost or benefit, since electricity export is assumed to be sold for free. This statement is supported by the fact the the pumping of the water takes place between the times with the lowest and highest level of the dams, and simultaneously having electricity exports (see figure 3.6 and 3.4). Hence, if there was a need and/or a possibility to store electricity in the dams, there would not be electricity exports.

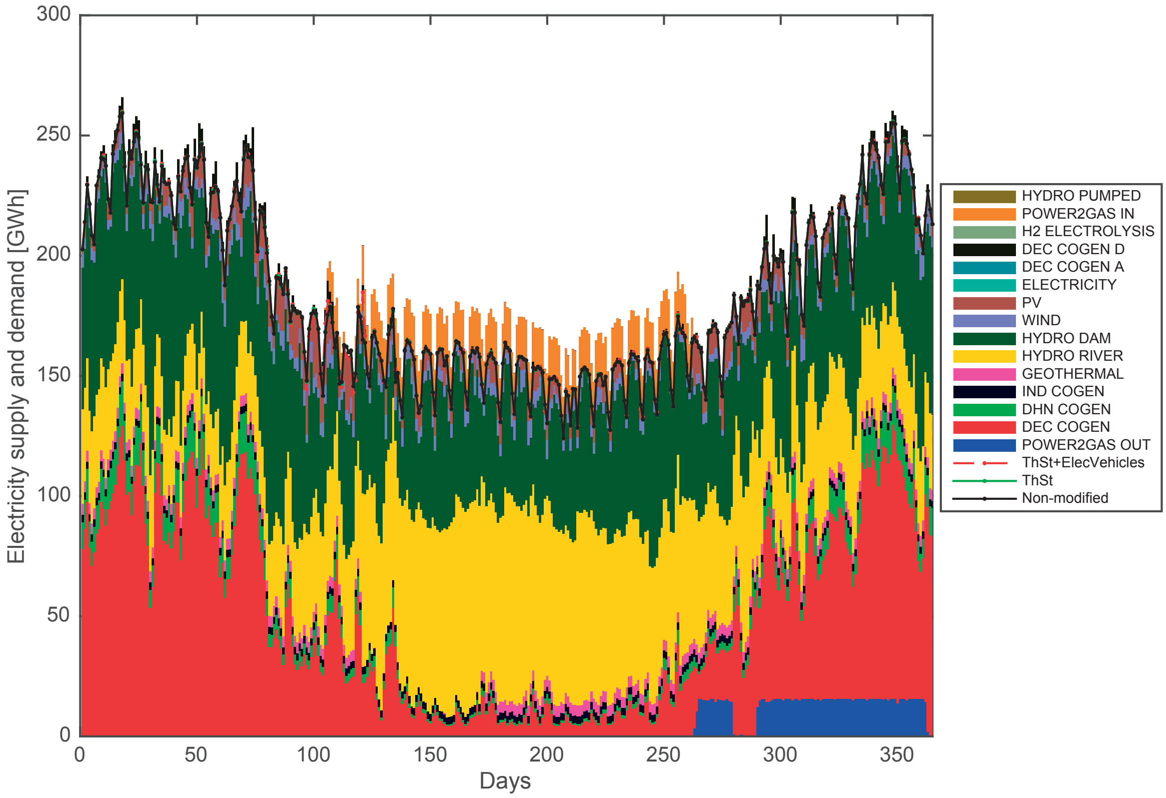

Figure 3.5 – Electricity supply and demand with daily time resolution for the scenario 1. HYDRO PUMPED, POWER2GAS IN, H2 ELECTROLYSIS represent consumption of electricity. DEC COGEN D indicates the amount of electricity not being produced since its production is shifted thanks to the thermal storage. The rest of the bars are for electricity production. The “Non-modified" line reproduces the electricity demand like if there was no flexibility (no thermal storage) for the P2H technologies, and the electricity consumption from EVs was constant. The “ThDR" considers the implementation of thermal sotrage but constant electricity consumption from EVs. And “ThDR+ElecVehicles" considers the two options.

Considering scenario 4 allows to give an approximate of the cost of having a scenario in which Switzerland is not dependent on electricity import. The extra annual cost is 293 millions CHF. At the defined price for the imported electricity (90.06 CHF_{2015}/MWh_{elec}), it is more convenient from an economic point of view to import electricity, rather than increasing the PV installed capacity and deploying a P2G system for closing the seasonal electricity balance. The PV installed capacity stays at its lower bound (4.48 GW), which corresponds to the installed capacity in the NEP2035 scenario.

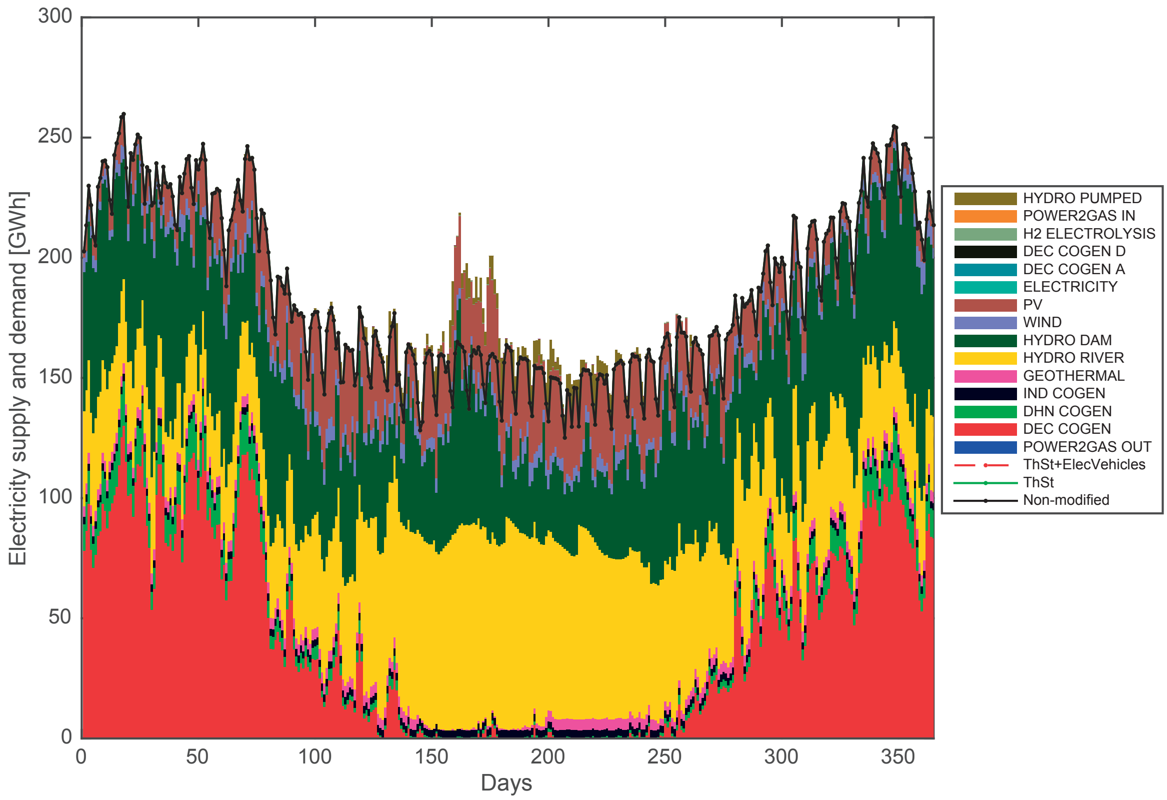

Figure 3.6 – Electricity supply and demand with daily time resolution for the scenario 2. See figure 3.5 for information on the legend.

In scenario 4, during summer the priority is given to the boilers to supply the low temperature heating over CHP systems. There is no P2G option, since it is cheaper to import electricity, hence the production of electricity during summer must be limited for not having excess electricity. In scenario 4, the levels of curtailment are 0.17%, 0.21% and 0.02% for PV, hydro dam and hydro river, respectively. These values are more than factor 10 lower than those in scenario 2. In addition no electricity export is reported in scenario 4. The consumption of natural gas and light fuel oil are respectively 3% and 12% lower than those in scenario 1.

Figures 3.9 and 3.10 are included to show the behavior of long and short term energy storage technologies in a winter and summer week, respectively. The P2G technology has quite an stable behavior. The input in the displayed summer week is constant at 0.68 GW. The output is constant at 0.65 GW in the winter week, except for a few hours where its output is zero. This operation strategy

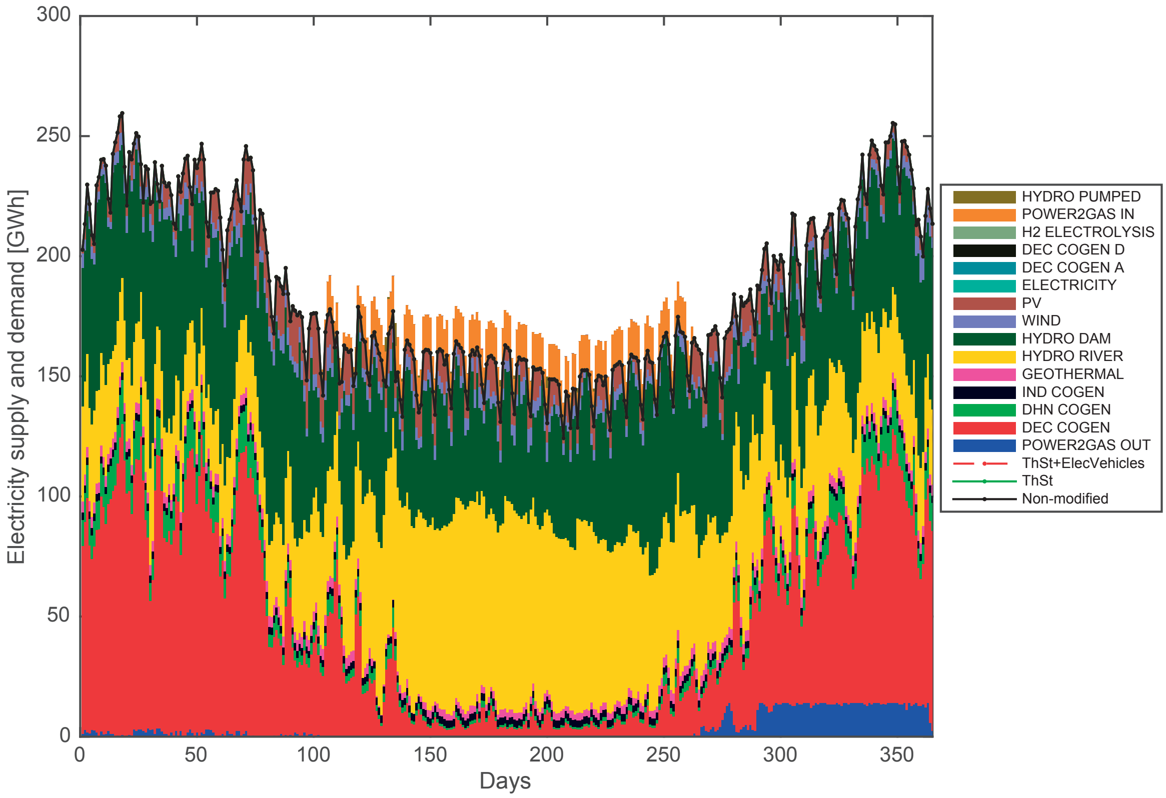

Figure 3.7 – Electricity supply and demand with daily time resolution for the scenario 3. See figure 3.5 for information on the legend.

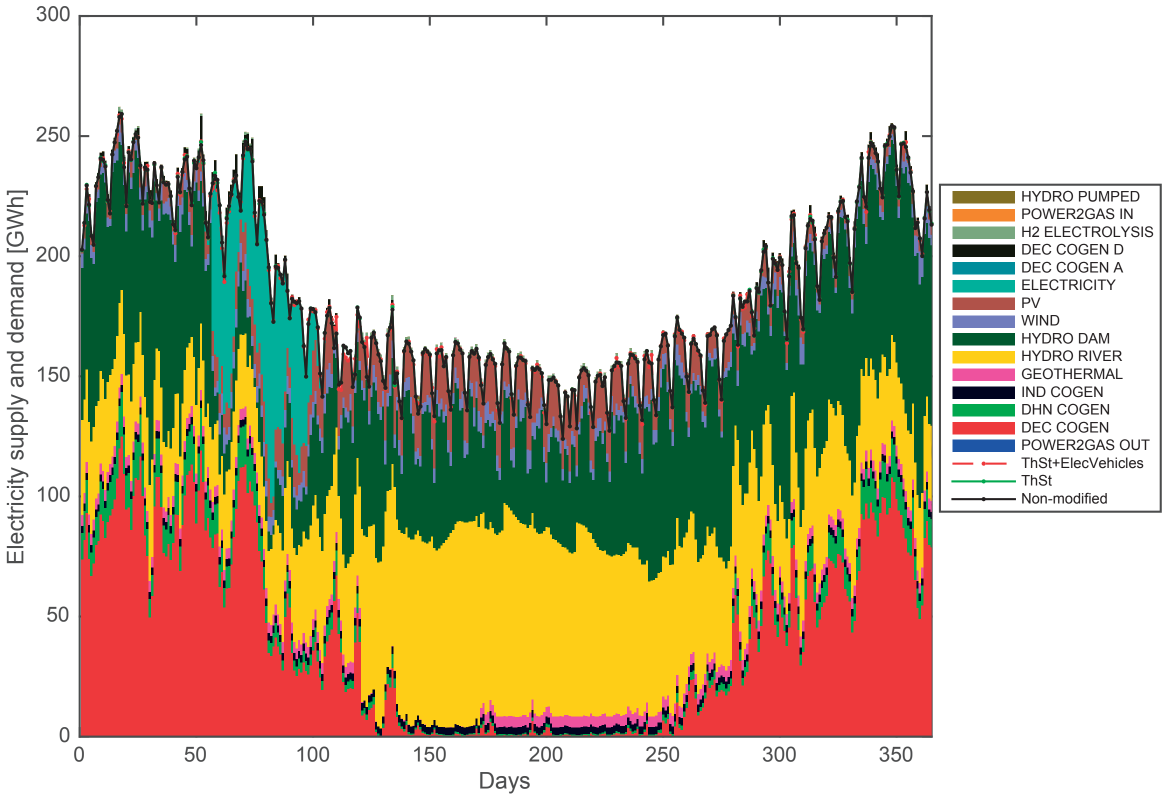

Figure 3.8 – Electricity supply and demand with daily time resolution for the scenario 4. See figure 3.5 for information on the legend.

minimizes the investment in the conversion technologies. In the summer week, the CHP systems supplying low temperature heat have a behavior complementary to the PV electricity supply. This is made possible thanks to the implementation described in section 3.3.1.

Thermal storage and smart charging has a less important role in balancing supply and demand in summer months than in winter months. That comes from the fact the low temperature heat demand is reduced to almost only hot water demand, and in addition the daily thermal storage capacity (**C**) defined in section 3.4.2 is lower. That can be better appreciated in figure 3.11. This figure compares the quantity of electricity consumption and production being displaced to the electricity demand for each day. For the smart charging a constant charging curve is considered as the reference for the calculation of the electricity demand being moved. The pics observed around the day 110 are due to the fact that in those days the dams are empty, hence the solver tries to use the thermal storage and smart charging to mitigate the lack of electricity stored in the dams.

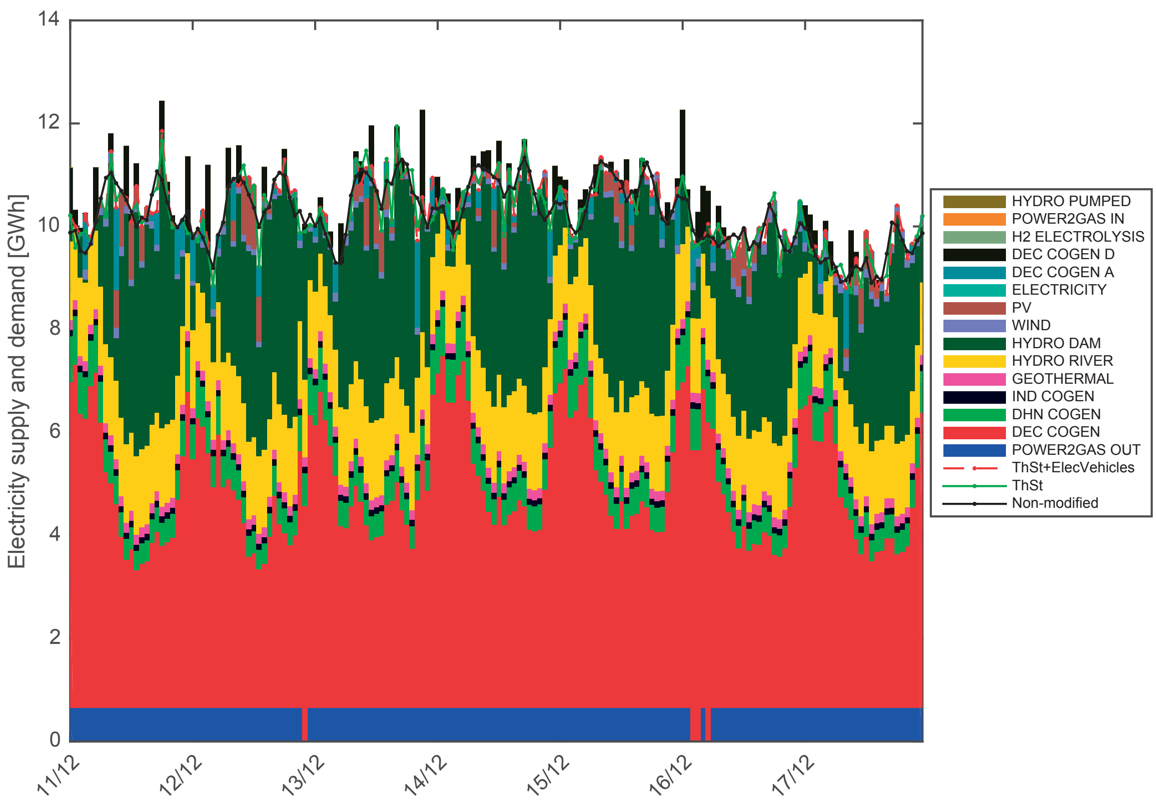

Figure 3.9 – Electricity supply and demand with hourly time resolution for a week in December for the scenario 1. See figure 3.5 for information on the legend.

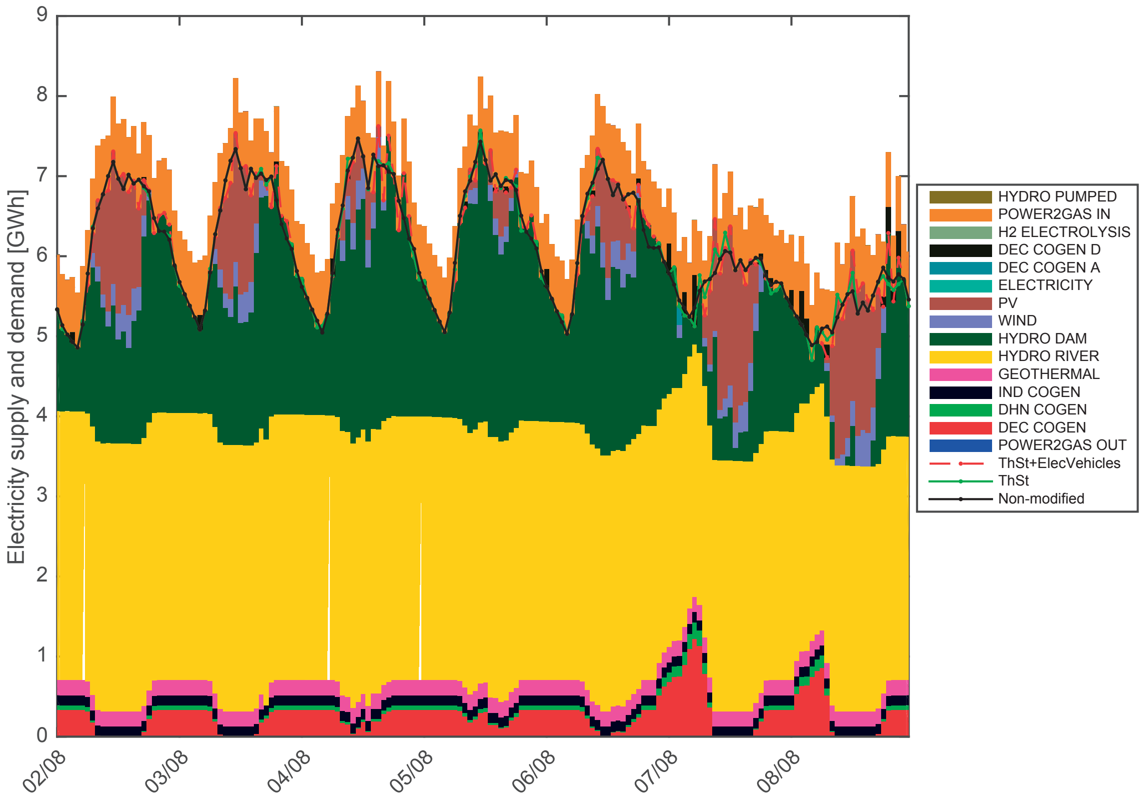

Figure 3.10 – Electricity supply and demand with hourly time resolution for a week in August for the scenario 1. See figure 3.5 for information on the legend.

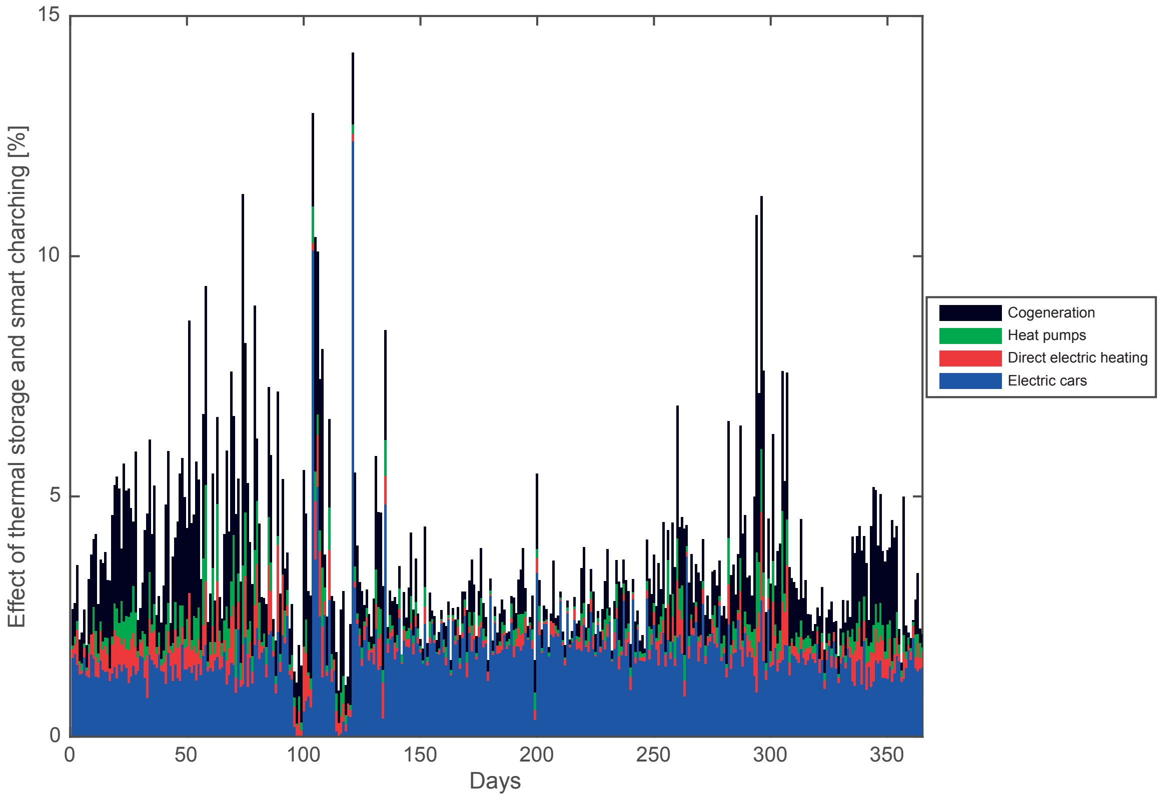

Figure 3.11 – Thermal storage and smart charging effect.

3.7 Conclusions

In this chapter we propose a model for the study of measures for the integration of renewable electricity. The suggested model is an extended version of the MILP model presented in [34]. The decision of using a MILP model of the complete national energy system encompasses both advantages and disadvantages. Having the national energy system as system scope offers the possibility to capture synergies among different sectors, by enlarging the space of solutions. In addition, the MILP formulation grants an optimal solution to the problem. The cost to pay is the solving time, as it might seem obvious, the larger the scope of the problem, the longer the calculation time.

As has been identified in the literature review, an energy model with an hourly time resolution is needed if the goal is to study the implementation of storage and flexibility options for the integration of variable renewable electricity. The MILP model from [34] has a monthly time resolution. When it is changed to hourly, the RAM memory required to solve the problem is heavily increased and exceeds the capacities of nowadays conventional desktop computers, since more than 8 GB of RAM are required. This is why we have proposed an alternative formulation to the part of the problem demanding the largest amount of resources.

We have implemented new capabilities in the already existing MILP formulation which should participate on the integration of variable renewable electricity:

- **NG and H_2 storage**. Since this option was not available in the formulation from [34], in each time step the production had to be equal or lower to the demand of the same energy vector. That constraint is eliminated by introducing the storage option.
- **Smart charging** of the electric private mobility.
- **Thermal storage** for the decentralised heat supply in buildings. It offers the possibility to use the thermal mass of building and heat storage tanks in order to modify the operation curve of HPs, CHP and DEH systems.
- **New formulation for hydro dam** electricity production. In the previous formulation from [34], the electricity production profile was a parameter. With the new implementation, the parameter is the natural water inflows into the dams. Hence the optimiser can decide on the best operation strategy.

We have put special attention not to reproduce one of the main weaknesses identified in the literature review: the lack of precision and/or methods in defining potentials and constraints in the implementation of demand side management in the energy models. For the thermal storage option, we have used results on the operation of a set of buildings representing the Swiss building stock which were generated using a MPC model, generated by a research-group colleague: Paul Stadler [202]. In the implementation of smart charging we have considered several cars with different usage profiles for better reproducing the cars usage at national level in comparison with the implementations found in the literature review.

The vast majority of authors use historical profiles of the national electricity demand without questioning themselves about the validity of those profiles. Due to the electrification of the energy system, i.e. strong deployment of HP and electric mobility, the shape of those profiles will certainly change. Hence isolating some of the most important components of the electricity demand curve is a key aspect. This is the reason why we introduced a novel methodology for calculating the part corresponding to the space heating needs in the national electricity demand profile. The methodology computes the electricity consumption profile for space heating for a year with an hourly time resolution. When comparing the annual electricity consumption for space heating obtained through the new methodology and the reported value in the statistics, the error is below 10%.

All the presented methodological developments have been tested in a case study for Switzerland. In addition, the case study allows to answer two questions:

- What is the extra cost to pay for not having electricity imports?
- What is the economic impact of the implementation of flexibility and storage options for integrating the variable renewable electricity?

We have chosen the Swiss NEP scenario for 2035 as a base for the case study. In this scenario, Switzerland depends on electricity imports to match supply and demand, specially outside the summer season. In order to avoid the need to import electricity, we propose an increase on the installed capacity of PV, which can be combined with the use of a set of long-term storage technologies and flexibility options. We have combined different degrees of implementation for the long-term storage (H_2 storage, NG storage and P2G) and flexibility options (smart charging and thermal storage in buildings) with the allowance to import or not electricity, which resulted in 4 new energy scenarios.

The first conclusion that can be extracted from the results is that under the current set of parameters, the difference between the scenarios with the highest and lowest total annual cost is only 2.5%. The most expensive scenario (scenario 2) corresponds to the one in which no P2G, smart charging and thermal storage are included. Hence that results in a strong increase of PV installed capacity in comparison with the other scenarios. The cheapest scenario corresponds to the only one in which electricity imports are allowed (scenario 4). The difference between scenarios is reduced to 1.5% when we compare scenario 4 to the least expensive one without electricity imports, but including all electricity storage and flexibility options. Hence, such is the cost of warrantying the autonomy of Switzerland in terms of electricity supply.

Conclusions

The following four research questions motivated the work presented in this thesis:

1. "*How can we increase energy literacy among decision-makers?*"
2. "*What is the cost of the integration of new renewable energy sources?*"
3. "*How can we optimise the use of biomass?*"
4. "*Which are the best alternatives for dealing with the variability of the electricity supply from renewable sources?*"

We have addressed these questions through the methodological contributions presented in the three chapters of the thesis.

In this thesis we have developed two different strategies on how to address the problem of the integration of renewable energy sources for the energy transition. The first one corresponds to chapter 1, which consists of using energy modelling to provide user-friendly yet rigorous tools to decision-makers, which should help them to comprehend the strategic, socio-economic and environmental impact of choices. The second strategy, common to chapters 2 and 3, profits from the possibilities offered by mathematical modelling and optimisatin to analyse national energy systems, and derive insights for policy and decision-makers.

Relevance of work

Having a clear terminology, and a classification for models and tools facilitates the strategic choices for any project involving energy modelling. This is reason why chapter 1 starts by tackling this issue. The choice of the tool, model and its modelling approach depends on the goal of the project, the tool-targeted users and the aspects of the energy system to be studied.

The main result of chapter 1 is the development of the Swiss-Energyscope online calculator [192]. For the Swiss-Energyscope calculator, we chose a simulation tool since it shall allow users to analyse different energy scenarios while introducing them to some of the key aspects of the energy sector. The model falls in the snapshot category because one of the key aspects of the Swiss energy system is the seasonal component of the energy supply and demand.

Often, energy models are very complex and thus inadequate for decision-makers which are not specialists in the domain. Hence, in the definition of the modelling approach we tried to find the trade-off between low level of complexity and scientific rigour. The defined approach warranties that the calculation time is below 1 s. This is a key aspect since the tool targets non-specialised users, which may use the "try and error" method as a learning technique.

In the modelling approach, special attention has been paid to not having predefined solutions to problems, like it is done for instance in "The 2050 Webtool" with the automatic computation of the amount of power plants for balancing electricity supply and demand. Predefined options may play against the understanding of the problem by users and also not take into consideration other feasible solutions. Finally we present a clear distinction between choices at supply and demand. For example, the consumption for space heating can be reduced by improving buildings insulation or by replacing boilers by efficient technologies such as heat pumps. This bring us to the way final energy consumption is displayed, substituting the common division by sectors (households, services, industry and transportation), by a legend highlighting the competition between electricity and fuel driven technologies for heating and transportation.

The approach used for the development of the cost model provides an estimation which allows users to compare two energy scenarios in terms of economic cost. It also reduces the model complexity and calculation time in comparison to already existing models, such as models belonging to the TIMES/MARKAL family, since no installation/decommissioning pathway is computed. The cost sensitivity to assumptions is made obvious by the use of the "Cost" inputs.

Part of the modelling approach also consists on selecting the key performance indicators. To the best of the author's knowledge, no large-scale energy model or tool includes exergy as one of the indicators. The development of a new exergy indicator to assess scenarios of national energy transition provides a more coherent way to quantify the exergy efficiencies linked to each transformation steps from primary to final and useful exergies. It also highlights in which sector of usage energy progress can be made and allows to efficiently compare scenarios. It also provides a tool for policy makers to favour the best technology options with adequate policies.

The second part of the thesis focuses on providing advice to policy-makers based on the use of modelling and optimisaiton of large-scale energy systems.

In chapter 2, biomass conversion options are compared taking into account the complete bio-energy conversion pathway, from the resource to the supply of energy services. In a first step, the comparison is done following a substitution approach, which is one of the methods identified in literature. Howerever, this way of performing the comparison does not take into consideration the seasonal component of the energy supply and demand. Moreover, it does not analyse the effect of the introduction of the biomass pathway on the complete energy system. Hence, in a second step the comparison is performed by evaluating the CO_2 abatement potential of integrating these different pathways into a national energy system with a MILP modelling approach. The comparison is done with 56 scenarios, which are classified in two different groups. In the first group the choice of the biomass chemical conversion process is the only possible change in the system. In the second group, other changes are allowed in the energy system, such as an important deployment of efficient technologies. Results show that biofuels can allow for an overall better performance in terms of avoided CO2 emissions compared to direct combustion of biomass. To exploit this potential, however, it is necessary to link the production of biofuels to a wider deployment of the corresponding efficient end-use technologies.

An evolutionary algorithm is also used to explore the different uses of woody biomass in Switzerland for the year 2050. The analysis demonstrates that the use of woody biomass in gasification-methanation systems, coupled with electrolysers and combined with an intensive deployment of PV panels and efficient technologies, reduces the natural gas imports to zero. Electrolysers are used to boost synthetic natural gas production by hydrogen injection into the methanation reaction. The hydrogen used is produced when there is excess of solar electricity. Nevertheless, the electrolyser is not the only technology in the scenarios that absorbs PV electricity in order to not have electricity exports. To meet these constraints, it is necessary to invest 0.3 Swiss Francs (CHF) in HPs and 0.6 CHF in the gasificaton-methanation and electrolysis (Bio2CH4el) technologies for every CHF invested in PV capacity.

Hence, from chapter 2 we can derive two key messages for policy-makers:

- The deployment of biomass chemical conversion technologies should be accompanied by a wider deployment of efficient technologies such as heat pumps, cogeneration or electric vehicles.
- Energy policies should not only target promotion of the deployment of PV, but also the technologies that will allow dealing with the variable electricity supply from PV.

HPs and Bio2CH4el are not the only options for the integration of variable renewable electricity. For that reason in chapter 3, we present the development of a model that considers a larger set of possibilities, among them flexible CHP and P2H thanks to the use of thermal storage in buildings, smart charging for EVs or P2G. The developments are tested with a case study of the Swiss energy system in 2035. The case study shows that the flexibility options and P2G reduce the total cost of the energy system, but they do not have a substantial impact. The difference between equivalent scenarios with and without smart charging, thermal load management and P2G is about 1.5%, in terms of total cost of the energy system.

Outreach

The Swiss-Energyscope online calculator and by association the model behind the tool, which is presented in chapter 1, are the basis for a list of new projects. A version of the online calculator for the Canton of Vaud in Switzerland have been developed. That demonstrates the adaptability of the tool and model. The Direction of Energy, or “Direction de l’Energie” (DIREN) of the Canton of Vaud, has chosen the Vaud-Energyscope calculator as the reference tool for the development of the cantonal energy strategy. This means that the tool offers the required balance between user-friendliness and scientific rigour which makes it adapted for policy-makers.

At national level, the Swiss National Bank (BNS) have decided to include the Swiss-Energyscope calculator in their online education platform for high school students, Iconomix [215]. The version in the Iconomix platform has the employment as new indicator. In this way, it is possible to see the impact of the energy transition in terms of jobs creation. This new indicator demonstrates the validity of the approach for the cost calculation of the energy system, since it provides the basis for the employment calculation.

The Swiss-Energyscope calculator is also one of the existing online energy calculators at which researchers looked at for the putting in place the “EU calc” project [216]. The EU calc project is a Horizon 2020 project financed by the European Union. Its goal is to develop a European online energy calculator. EPFL is research partners in the project, which valorises the knowledge and experience acquired during the conception of the Swiss-Energyscope calculator.

Future prospects and developments

Future perspectives are envisioned along five main research tracks:

- **Introduction of the multi-regional calculation.** The concept consists on solving the MILP problem presented in chapter 3 for determining the investment and operation strategy of a large-scale energy system, e.g. country like Switzerland, formed by a set of subsystems or regions, e.g. cantons. The different regions present variations in terms of renewable energy potential, energy demand or production and demand profiles. Hence each region will have a customised solution depending on its characteristics. The optimiser should also determine the energy flows between regions. This new functionality is not methodologically complicated to implement. It can be done by introducing a new index for any parameter, variable and equation of the MILP problem, which will determine the region it belongs to. Nevertheless, that will represent an strong increase in the number of parameters, variables and equations, hence more calculation time and RAM memory consumption.
- **Implementation of the typical days.** One of the options to reduce the size of the optimisation problem is to use temporal clustering techniques. A year can be decomposed in a set of typical

days, statistically calculated. Then the MILP can be solved for each one of the typical days, which strongly reduces the solving time in comparison to considering simultaneously the 8760 hours (time steps) of a year. Implementing the typical days formulation in the MILP model from chapter 3 would most probably make feasible the inclusion of the regional dimension into the problem.

- **Application of the methodology to other regions or countries.** It has already been demonstrated the adaptability of the model and tool presented in chapter 1 thanks to the development of the Vaud-Energyscope calculator. On the other hand, it would be interesting to use the MILP formulation in chapter 3 to reproduce the energy system of another country, in order to evaluate the relevance of the storage and flexibility options for the power sector when there is no hydro dam installed capacity. Since hydro dams plays an important role on balancing electricity supply and demand.

A Implementation of hydro power and electricity seasonal storage.

This appendix contains a detailed analysis of the potential and cost for hydro dam and hydro river in Switzerland as well as the description of the electricity seasonal storage technology. This work is a result of a collaboration with Moret et al. and it has been published in the SI of [34].

A.1 Hydro power in Switzerland

The projected capacity factors for hydroelectric run-of-river plants and dams are calculated based on the data in Table A.1. A decrease in the electricity production is expected in the next years due to the application of the LEaux law [13]. The law defines the minimum flow rates for rivers. In order to respect them, during some periods of the year it may be necessary to stop the power plants. In these cases, the water will flow bypassing the turbines. This will have as a consequence a decrease in the annual electricity production. The decrease in electricity production is estimated to be 1400 GWh/y [13]. In the model, the LEaux production penalty is shared between run-of-river plans and dams proportionally to their net yearly electricity production. The net electricity production is the total electricity production minus the electricity consumed for the pumping in the hydro dams.

Table A.1 – Data for the calculation of the future capacity factors for hydro run-of-river and dams.

	Hydro river	**Hydro dam**
Net electricity production (2012) [GWh] [217]	16981	17297
Installed power (2012) [GW] [217]	3.84	8.08
LEaux effect [GWh] [13]	-686	-714
c_p **[%]**	48.4	23.4

The SFOE has evaluated the development potential for hydroelectricty [13]. The results of the study are presented in Table A.2.

Table A.2 – Development potential for hydroelectricity in Switzerland [13].

	Additional net electricity production	
	Current conditions [GWh/y]	Optimized conditions [GWh/y]
New big plants	770	1430
Small hydro	1290	1600
Transformation, extension	870	1530
Total potential	2930	4560

Forecasts in [12] for the year 2050 are based on the development potential under optimized conditions in Table A.2. This potential is distributed between hydro river and hydro dam (Table A.3).

Table A.3 – Development potential for hydroelectricity in Switzerland by 2050 [12].

	Additional net electricity production [GWh/y]
Small hydro	1600
Hydro run-of-river	2000
Hydro dams	900
Total potential	4500

In the model, this additional potential is added to the 2012 net electricity production to obtain the electricity production potential of Swiss hydroelectric power plants in 2050 (Table A.4). The small hydro potential is attributed to the hydro run-of-river technology as additional capacity. The values in Table A.4 for 2050 already include the decrease in production caused by the LEaux law.

Table A.4 – Net hydroelectricity production and installed power in Switzerland in the years 2012 and 2050.

	2012 [217]		**2050**	
	Production [GWh/y]	**Power**[a] [GW]	**Production** [GWh/y]	**Power**[a] [GW]
Hydro river	16981	3.84	19895	4.69
Hydro dam	17297	8.08	17483	8.52

[a] The capacity factors in Table A.1 are used to calculate the installed power in 2050.

For the cost calculations, it is necessary to consider the way in which the additional electricity is produced (new dams, new run-of-river plants, improvement and renovation of existing plants). Table A.5 estimates this repartition based on data from [12] and [13].

Table A.5 – Development potential of hydroelectricity in Switzerland by 2050.

	Additional net electricity production	
	Hydro river [GWh/y]	**Hydro dam** [GWh/y]
Renovation	677	463
Dams height increase	0	330
New big plants	1324	108
New small plants	1600	0

Increasing the heights of existing dam has two consequences: an additional net electricity production (Table A.5) and an additional storage capacity of 2400 GWh [128]. Currently in Switzerland there is an electricity deficit during winter and an electricity surplus during summer months. Hydroelectric dams help equilibrating the seasonal balance by storing a fraction of the water harvested during spring and summer, for additional electricity production in winter months. Nonetheless, this "shifting capacity" is limited, as dams are forced to turbine water during summer months (despite the excess of electricity production) to avoid the risk of dam overflow [124]. The additional storage capacity allows to shift electricity production from summer to winter, meaning that 2400 GWh can be subtracted from the summer production, and be delivered in winter.

Table A.6 and Table A.7 contain the data used for the calculation of the specific investment and O&M costs. The capacity factors calculated in Table A.1 are used for the calculation of the installed power.

Table A.6 – Investment cost data for the new hydro power plants in Switzerland.

	Hydro river			Hydro dam		
	Power [GW]	c_{inv} [CHF_{2015}/kW_e]	**Total Inv.** [10^6 CHF_{2015}]	**Power** [GW]	c_{inv} [CHF_{2015}/kW_e]	**Total Inv.** [10^6 CHF_{2015}]
Renovation	0.16	4278 [131]	683	0.23	2849 [131]	643
Dam height increase	-	-	-	0.16	3807	612[a]
New big plants [218]	0.31	5387	1681	0.05	4828	254
New small plants	0.38	7054[b]	2660	-	-	-
Total	0.85	5919	5023	0.44	3437	1509

[a] The investment cost for increasing the height of dams is proportional to the amount of extra electricity associated to the increased potential energy of the water: [0.8, 0.9] CHF_{2015}/kWh [128]. The mean of the interval is used in the calculations.
[b] Average between values in Table 2-4 and in Table 2-5 for new small plants in 2035 [131]

Table A.7 – O&M cost data for the new hydroelctric power plants in Switzerland.

	Hydro river			Hydro dam		
	Power [GW]	c_{maint} [$CHF_{2015}/kW_e/y$]	**Total O&M** [10^6 CHF_{2015}]	**Power** [GW]	c_{maint} [$CHF_{2015}/kW_e/y$]	**Total O&M** [10^6 CHF_{2015}]
Renovation	0.16	-	-	0.23	-	-
Dam height increase	-	-	-	0.16	-	-
New big plants [218]	0.31	54 [218]	16.8	0.05	24 [218]	1.27
New small plants	0.38	127[a]	47.9	-	-	-
Total	0.85	76.3	65.7	0.44	2.89	1.27

[a] Average between values in table 2-4 and in table 2-5 for new small plants in 2035 [131]

A.2 Seasonal storage

The seasonal storage option provided in the model consists in the production of synthetic methane from the excess of electricity. This synthetic methane is then used for producing electricity during periods of deficit in electricity supply. This procedure is also known as Power-to-NG-to-Power. The seasonal storage model is based on the liquified CH_4-CO_2 system (LM-C) presented by Al-musleh et al. [77]. It consists of a reversible FC which is used as electrolyzer to produce hydrogen when there is excess electricity in the grid. The hydrogen is sent to a methanation reactor where it is mixed with CO_2 to produce methane which is liquified (liquified natural gas (LNG)) previous to storage. When there is a shortage of electricity, the methane is gasified and oxidized in the FC to produce electricity. The produced CO_2 is liquified and stored for being used as input of the methanation reaction; thus, this system is a carbon closed loop, as there is no emission of CO_2.

The elements considered for the calculation of the investment and O&M costs are the reversible FC, the liquefaction train and the tanks for storing CH_4 and CO_2. The data required for the cost calculation is available in Table A.8. It has been assumed that the O&M cost (c_{maint}) are 5% of the initial investment cost, and that the lifetime of the different components is 25 years.

Table A.8 – Data for the seasonal storage cost calculation.

	Parameter	Unit	Value
Technical data [77]	Lower Heating Value (LNG)	[MJ/kg]	50
		[MJ/m^3]	21882
	Roundtrip efficiency	[%]	56.1[a]
	Storage requirement	[$m^3_{CH_4}$/$GWh_{e,out}$]	232
		[$m^3_{CO_2}$/$GWh_{e,out}$]	264
Specific investment cost (c_{inv})	Tank	[$kCHF_{2015}$/$GWh_{e,out}$]	585[b]
	Liquefaction plant	[CHF_{2015}/kW_{LNG}]	233[c]
	Reversible FC	[CHF_{2015}/kW_e]	2934[d]

[a] Power-to-LNG efficiency is 79.2% and LNG-to-Power efficiency is 70.8% [77].
[b] Accounting for the investment of the CO_2 and CH_4 tanks. Based on the average of the cost interval 94-283 $MCHF_{2015}$ for a 160000 m^3 tank in Hjorteset et al. [219], which is 1180 CHF_{2015}/m^3.
[c] Average of the points in [220] (Figure 17), excluding high cost locations.
[d] System cost (including markup) for a 5 kWe solid-oxide FC system, assuming an annual production of 50000 units [221].

B Woody biomass conversion technologies

The appendix contains a review on biomass conversion technologies.

Woody biomass conversion technologies convert the woody biomass resource into energy services or into energy carriers (liquid or gaseous fuels, or electricity).

B.1 Gasification and methanation for bio-SNG production

This pathway combines two thermo-chemical technologies, gasification and methanation, to produce bio-based synthetic natural gas (bio-SNG) and CO_2 from woody biomass. Eq. B.1 represents the overall chemical reaction stoechiometry. A drying step is needed before the gasification process for decreasing the humidity below 20 %, in order to ensure the proper functioning of the gasification. The gasification process, which takes place at 800-900°C in an oxygen restrained environment [222][223], decomposes the biomass into syngas, a mixture of CH_4, H_2, CO, CO_2 and H_2O. The syngas is then cleansed before being converted to CH_4 (SNG) and CO_2 by the methanation process in a catalytic reactor (using nickel catalysts) at 300-400°C. Depending on the biomass composition and the specific gasification technology, the output of the reactor will contain between 40 and 50 % volume of methane (CH_4), which has to be separated from the CO_2 and the remaining H_2 if one wish to inject it in the natural gas grid [222] [223]. The complete process is depicted in Figure B.1. The fuel efficiency of the complete process ($\text{EnergyOutput}_{\text{SNG}}/\text{EnergyInput}_{\text{Biomass}}$) is expected to range from 39 to 75 % [5], depending on the biomass composition and moisture content.

$$CH_{1.35}O_{0.63} + 0.3475 H_2O \rightarrow 0.51125 CH_4 + 0.48875 CO_2 \qquad \Delta h^0 = -10.5 kJ/mol_{biomass} \tag{B.1}$$

The critical part of this pathway is the methanation step. Although the 2-stage process feasibility has been demonstrated in pilot plant scale, like the one in Guessing (Austria) producing 1 MW_{SNG}, the technology has not yet reached commercial status [224]. The Swedish project GOBIGAS in Göteborg

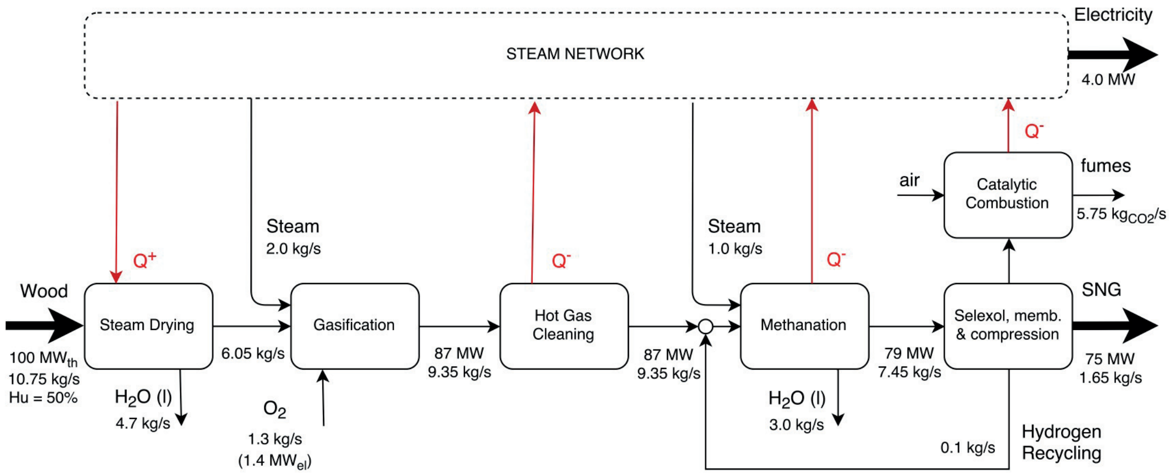

Figure B.1 – Flow diagram of a 100 $MW_{th,wood}$ gasification plant without cogeneration based on directly heated pressurised gasification system [5].

expects commissioning of the world's first large-scale commercial methanation plant supplying 100 MW_{SNG} by 2020 [225].

B.1.1 Power-to-gas for bio-SNG production

A variant of the gasification-methanation pathway consists in combining it with a power-to-gas (PtG) process. Renewable electricity is used to produce hydrogen (H_2) in an electrolyzer. The hydrogen is then injected in the methanation reactor to increase the CH_4 output (see Figure B.2). As shown in Eq. B.3, the use of H_2 does indeed increase the CH_4 yield while reducing the CO_2 emissions of the bio-SNG production process. This combined biomass gasification pathway is particularly relevant as a mean to store electricity in regions that have excess production of renewable electricity.

$$H_2O \rightarrow H_2 + 1/2O_2 \qquad \Delta h^0 = 286 kJ/mol_{H_2O} \quad \text{(B.2)}$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta h^0 = -165.0 kJ/mol_{CO_2} \quad \text{(B.3)}$$

This variant of the methanation process increases the energy content per unit of biogenic carbon in the input from 21.5 MJ_{LHV}/kgC_{input} for the process without electrolysis to 52.8 MJ_{LHV}/kgC_{input} for the conversion process integrating the electrolysis. Thus woody biomas serves as a carbon source for electricity storage into synthetic fuel, with an electricity-to-fuel efficiency of 68 %. This efficiency compares the increase on the SNG production to additional electricity consumption. Equation B.4 shows the way it is defined, where $Fuel$ is the energy content (LHV based) of the produced biofuel, $InElec$ is the electricity input, $OutElec$ is the electricity output, $Elec$ and $NoElec$ are the subscripts for the technology with an without electrolysis respectively. An alternative to the use of wood as

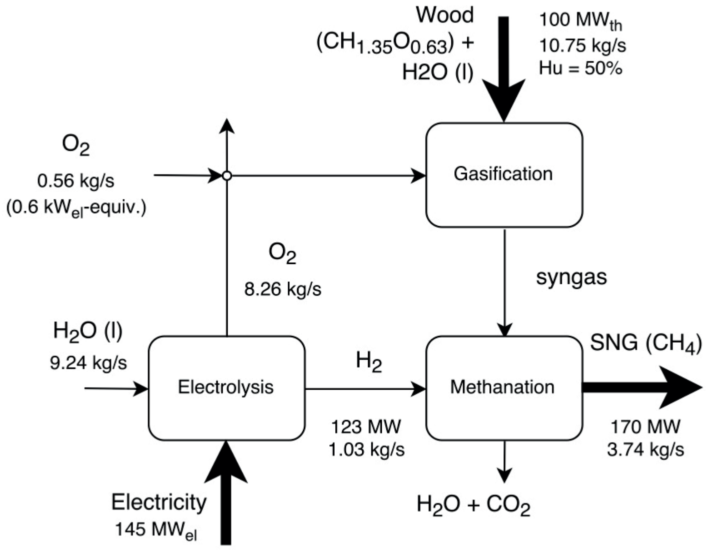

Figure B.2 – Integration pathway of the electrolysis in the directly heated gasification - methanation system. The mass and energy flows correspond to the system design in in [6], that maximizes the bio-SNG production .

carbon source consists in capturing the CO_2 directly from the atmosphere, but the electricity-to-fuel efficiency then drops to to 52% [166].

$$\eta_{ElecToBiofuel} = \frac{Fuel_{Elec} - Fuel_{NoElec}}{(InElec_{Elec} - InElec_{NoElec}) + OutElec_{NoElec}} \tag{B.4}$$

B.2 Hydrothermal gasification (HTG) for bio-SNG production

Hydrothermal gasification (HTG) is a promising technology for the production of bio-SNG from wet woody biomass or any biomass with moisture content between 50 and 80 % [14]. As for the gasification/methanation process, HTG fully converts the energy content of the biomass into gas, electricity and heat. Its main advantage over other conversion processes lies in the fact that the biomass is treated in supercritical water, thus avoiding the energy consuming drying step. Under supercritical conditions, the biomass macromolecules are hydrolysed and become accessible to the catalyst for the conversion into CH_4 and CO_2. In addition, the supercritical conditions requires less energy for heating up the water to the operating conditions.

Up to date, only lab-scale HTG facilities have been built [226] [227]. The performances in Table B.1 are based on models, which have been calibrated with data from laboratory experiments, in order to be able to calculate the efficiencies of an integrated industrial process.

As shown in Table B.1, the performance of the HTG process highly depends on the properties of the feedstock. In addition, the process heat demand is fairly sensitive to the level of dilution of the organic matter in the water. In this respect, hydrothermal gasification is in direct competition with bio-methanation (anaerobic digestion). In some cases these two technologies can actually complement each other as HTG can treat in a post-process the non-digested output from the bio-methanation reactor.

Table B.1 – Performances for the hydrothermal gasification with dry matter content of 20% [14]

Resource	**Humidity** [%]	**Organic matter content** [% kg/kg_{dry}]	**Efficiency** [%] SNG	Elec.
Food and organic industrial waste	70 - 50	>99	56 - 77	0 - 10
Wood	50	>99	50 - 65	4 - 13
Manure	97	75	54 - 68	-1 - 3
WWTP sludge	95	63	40 - 57	-1 - 5
-after digestion	95	52	18 - 44	-1 - 8

B.3 Fischer-Tropsch (FT) process for producing synthetic liquid fuels

The biomass to liquids (BTL) conversion pathway considered in this study consists in the synthesis of Fischer-Tropsch fuels from lignocellulosic biomass. The first step of the process is the pretreatment by which raw biomass (35 % moisture content) is dried, torrefied, and ground into fine particles. The biomass particles are then gasified in a pressurized (30 bar) steam-oxygen blown entrained flow gasifier. The synthesis gas produced, consisting mainly of H_2, CO, CO_2 is cooled by a water quench and cleaned in a scrubber. A water gas shift (WGS) reactor is used to adjust the H_2 to CO ratio and CO_2 is removed by amine scrubbing in order to satisfy the requirements of the FT synthesis by which the liquid hydrocarbon fuels are produced. This process is described in detail in [165], as a reference process using entrained flow gasification with ”most conventional technologies" and converting 200 MW_{th} (on a LHV daf basis) of lignocellulosic biomass.

FT fuels can be blended to diesel fuel. Methanol production is an alternative BTL conversion pathway with similar conversion to the FT fuel pathway. Methanol can be blended with gasoline [228].

B.3.1 Power-to-Gas (PtG) for FT liquid fuel production

In the above Fischer-Tropsch (FT) process, as an alternative to the water gas shift reaction, steam electrolysis can be used to provide the required amount of H_2 to reach the needed H_2 / CO_2 ratio. The addition of H_2 increases the amount of carbon that is converted into liquid fuel. As in the gasification/methanation & electrolysis combination discussed above, the use of hydrogen from electrolysis serves as a long term storage option for excess renewable electricity.

The integration of steam electrolysis in the FT-process increases the energy content per unit of biogenic carbon in the input, rising from 13.4 MJ_{LHV}/kgC_{input} for the process using the water gas shift reaction to 26.1 MJ_{LHV}/kgC_{input} for the conversion process with the electrolysis. The marginal efficiency of the conversion of electricity into FT fuel is 78 %. Equation B.4 defines the marginal efficiency.

B.4 Biomass integrated gasification combined cycle (BIGCC) for electricity production

A biomass integrated gasification combined cycle (BIGCC) uses a pressurised gasifier to convert woody biomass into synthesis gas (syngas), which consists mainly of H_2, CO and CO_2. The syngas is then cleansed from impurities prior to entering a gas turbine to generate electricity. In order to maximise the electrical efficiency, the heat content of the flue gas is then used in a boiler for producing steam, which subsequently expands in a bottoming steam turbine to further produce electricity. A BIGCC is identical to a natural gas combined cycle, in which gasified biomass substitutes natural gas as input to the gas turbine.

B.5 Integrated Gasifier-SOFC-GT system for electricity production

This integrated system converts woody biomass to electricity with a maximum efficiency of 71 % [174]. The biomass is first dried to 10-25 % moisture content. The dry wood then enters a directly heated fluidized bed gasifier (CFB) to produce syngas, which fuels a solid oxide fuel cell (SOFC) - gas turbine (GT) hybrid cycle. Prior to injection into the hybrid cycle the syngas produced in the gasifier is sent to the hot cleansing unit to remove particulates, sulfur and tar, in order to reach the required syngas purity specifications required by the SOFC. The SOFC outlet stream is at high temperature and still contains some syngas. Thus it has a high exergy content, which is exploited in a gas turbine to produce additional electricity [173]. If the combustion in the gas turbine is made with pure oxygen, the flue gases only contain CO_2 and water vapour. The water vapour can be condensed to separate the CO_2 which can be compressed for its transport and storage (carbon capture and storage). A detailed description of the system is available in [174].

B.6 Torrefaction as a biomass pretreatment

Torrefaction is a thermo-chemical process carried out at 200-300°C, with low heat-up rates (less than 50°C of temperature increase per minute), and long reaction time (about 1 hour). It may be used as pre-treatment process to upgrade woody biomass or other kinds of ligno-cellulosic biomass. It completely dries and reduces the hygroscopic nature of biomass, meaning that only 1 to 6% moisture content may be regained during storage. In comparison to raw woody biomass, torrefied biomass has a higher heating value and energy density. In addition torrefied biomass has better grindability and better properties for injection when used in boilers or gasifier, as it is a more homogeneous fuel than raw biomass. These characteristics make torrefied woody biomass a suitable substitute of coal in co-firing or gasification facilities, with a minimal efficiency penalty even in equipments designed for coal. Furthermore because of the low hygroscopic nature and higher energy density transportation costs can be reduced [229].

B.7 Data summary

This section contains the data on efficiency, cost and environmental impact for biomass technologies used in sections 2.3, 2.4 and 2.5. The data for all the other technologies included in the model are available in [34].

Table B.2 – Efficiencies of the energy conversion technologies in 2035.

Technology	Input		Output			
	Fuel [a] [kWh]	Electricity [kWh]	Fuel [a] [kWh]	Heat [kWh]	Electricity [kWh]	Mobility [pkm]
Hydrothermal gasification (HTG) [14]	100	–	65	–	5	–
Bio2CH4 [5]	100	–	69.3	–	3.7	–
Bio2CH4el [6]	100	144.5	170	–	–	–
Fisher-Tropsh (FT) [165]	100	1.64	43.3	–	–	–
FTel [165]	100	54.2	84.2	–	–	–
Fast pyrolysis (Pyro) [132]	100	–	67	–	2	–
Fast pyrolysis with upgrading (PyroUp) [172]	100	–	63	–	–	–
Gas-FC-GT [174]	100	–	–	–	71	–
Gas-FC-GT with CCS [174]	100	–	–	–	67.8 [b]	–
Biomass integrated gasification combined cycle (BIGCC) [231]	100	–	–	49	32	–
Externally-fired gas turbine (MGT) [232]	100	–	–	75	20	–
Torrefaction [229]	100	–	91	–	–	–
Wood boiler [153]	100	–	–	85	–	–
Oil boiler [153]	100	–	–	100	–	–
Gas boiler [153]	100	–	–	102	–	–
Gas CHP engine [127]	100	–	–	44	46	–
Oil CHP engine [112]	100	–	–	39	43	–
SOFC [233]	100	–	–	25	60	–
SOFC-GT [173]	100	–	–	16	80	–
SOFC-GT with CCS [173]	100	–	–	16	77.8 [c]	–
Combined Cycle Gas Turbine (CCGT) [127]	100	–	–	–	63	–
CCGT with CCS [127]	100	–	–	–	57	–
Supercritical plant [127]	100	–	–	–	46	–
Heat pump (HP) [153]	–	100	–	400	–	–
Car-Diesel [153]	100	–	–	–	–	259
Car-Compressed natural gas (CNG) [153]	100	–	–	–	–	207
Car-Electric [153]	100	–	–	–	–	944

[a] Fuel inputs and outputs are calculated based on their LHV. The LHV of wood is on wet basis, with 50 % humidity.

[b] Electricity penalty for CO2 compression for transportation and storage is 0.4 GJ_e/t_{CO_2} for the compression from 1 to 110 bar [230].

[c] Fuel inputs and outputs are calculated based on their LHV. The LHV of wood is on wet basis, with 50 % humidity.

Table B.3 – Specific investment cost (c_{inv}), O&M cost ($c_{O\&M}$), construction impact (gwp_{const}) and lifetime of the wood conversion units.

Technology	$\mathbf{c_{inv}}$	$\mathbf{c_{O\&M}}$	$\mathbf{gwp_{const}}$	**lifetime**
BIGCC	2337[a]	37[a]	184[b]	35[a]
MGT [232]	2304	115[c]	179[d]	15
Gas-FC-GT [174]	6141	328	555[e]	15
Bio2CH4 [132]	2168	111	40.2	25
Bio2CH4el[f]	2645	158	1247	25
FT [132]	4432	222	40.2	25
FTel[g]	4609	239	489	25
Pyro [132]	956	48	10.8	25
PyroUp [h]	2390	263	27	25

[a] Assumed to have the same c_{inv} and $c_{O\&M}$ as in IGCC coal power plant [34]

[b] Assumed to have the same gwp_{const} as "gas power plant construction, combined cycle, 400 MW electrical, RER" in Ecoinvent v3.2 [112]

[c] 5% of c_{inv}

[d] Value from "micro gas turbine production, 100 kW electrical, CH" in Ecoinvent v3.2 [112].

[e] Calculated as the sum of the gwp_{const} for the Bio2CH4 and a FC-GT system ("fuel cell production, solid oxide, with micro gas turbine, 180 kW electrical, future, CH" in Ecoinvent v3.2 [112]).

[f] Calculated as the sum of the data for the Bio2CH4 and an electrolyser: economic data for the electrolyser in [34], impact data corresponds to "fuel cell production, solid oxide, 125 kW electrical, future, CH" in Ecoinvent v3.2 [112].

[g] Calculated as the sum of the data for the FT and an electrolyser: economic data for the electrolyser in [34], impact data corresponds to "fuel cell production, solid oxide, 125 kW electrical, future, CH" in Ecoinvent v3.2 [112].

[h] c_{inv} and gwp_{const} assumed to be 250% of fast pyrolysis values, $c_{O\&M}$ assumed to be 550% of $c_{O\&M}$ fast pyrolysis.

C Results for the scenarios integrating the woody biomass pathways

The appendix contains the table with the results for the 56 scenarios displayed in Figure 2.9.

Table C.1 – Results of the 56 scenarios displayed in Figure 2.9.

Pathway	**Cost** [10^6 CHF]					**GWP** [10^3 $t_{CO_2\text{-eq}}$]			
	Investment ($\mathbf{C_{inv}}$)	**Maintenance** ($\mathbf{C_{maint}}$)	**Operation** ($\mathbf{C_{op}}$)	**TOTAL** ($\mathbf{C_{tot}}$)	**Relative** [%]	**Construction** ($\mathbf{GWP_{const}}$)	**Operation** ($\mathbf{GWP_{op}}$)	**TOTAL** ($\mathbf{GWP_{tot}}$)	**Relative** [%]
Boiler	11483	1916	6530	19930	0	4111	22013	26124	0
Bio2CH4	11497	1942	6553	19992	0.3	4106	22115	26221	0.4
Bio2CH4el	11803	2246	6247	20296	1.8	4482	20710	25192	-3.6
FT	11743	2165	6527	20435	2.5	4109	22485	26594	1.8
FTel	11794	2223	6339	20356	2.1	4132	21952	26084	-0.2
Pyro	11527	1968	6510	20005	0.4	4107	22204	26311	0.7
PyroUp	11544	2086	6464	20094	0.8	4108	22324	26431	1.2
Ind CHP	11492	1928	6585	20005	0.4	4105	22264	26370	0.9
Ind CHP - HP	11521	1947	6411	19880	-0.3	4111	21465	25576	-2.1
Ind CHP - BEV	11479	1919	6274	19672	-1.3	4107	21432	25539	-2.2
DHN CHP	11522	1950	6585	20056	0.6	4104	22264	26369	0.9
DHN CHP - HP	11519	1947	6411	19878	-0.3	4110	21465	25575	-2.1
DHN CHP - BEV	11484	1920	6330	19735	-1	4108	21618	25726	-1.5
Dec CHP	11515	1933	6520	19967	0.2	4120	21963	26083	-0.2
Dec CHP - HP	11560	1962	6298	19820	-0.6	4129	20943	25071	-4
Dec CHP - BEV	11899	2264	6036	20199	1.3	5047	20501	25547	-2.2
BIGCC	11657	1970	6523	20150	1.1	4108	21979	26086	-0.1
BIGCC - HP	11751	2051	5828	19630	-1.5	3971	18778	22749	-12.9
BIGCC - BEV	11493	1918	5948	19360	-2.9	4108	20534	24641	-5.7
MGT	11623	2010	6503	20136	1	4114	21886	26000	-0.5
MGT - HP	11676	2045	6310	20031	0.5	4121	20999	25120	-3.8
MGT - BEV	11986	2338	6088	20411	2.4	5054	20642	25696	-1.6
Gas-FC-GT	12030	2288	6592	20909	4.9	4146	22296	26442	1.2
Gas-FC-GT - HP	12229	2416	5911	20555	3.1	4172	19161	23333	-10.7
Gas-FC-GT - BEV	11799	2133	5366	19298	-3.2	4132	19018	23150	-11.4
Bio2CH4 - ThHP	11529	1966	6157	19652	-1.4	4087	20296	24384	-6.7
Bio2CH4 - Ind CHP	11488	1925	6564	19977	0.2	4112	22168	26280	0.6
Bio2CH4 - Ind CHP - HP	11554	1970	6208	19731	-1	4124	20527	24651	-5.6
Bio2CH4 - Ind CHP - BEV	11479	1918	5930	19327	-3	4111	20480	24591	-5.9
Bio2CH4 - DHN CHP	11488	1925	6564	19977	0.2	4112	22168	26280	0.6
Bio2CH4 - DHN CHP - HP	11555	1971	6207	19733	-1	4124	20526	24650	-5.6
Bio2CH4 - DHN CHP - BEV	11480	1918	5945	19344	-2.9	4111	20551	24662	-5.6
Bio2CH4 - Dec CHP	11501	1953	6560	20014	0.4	4119	22149	26268	0.6
Bio2CH4 - Dec CHP - HP	11562	1999	6246	19807	-0.6	4131	20704	24835	-4.9
Bio2CH4 - Dec CHP - BEV	11485	1933	6057	19475	-2.3	4114	20919	25034	-4.2
Bio2CH4 - Adv CHP	11563	1942	6586	20091	0.8	4122	22269	26392	1
Bio2CH4 - Adv CHP - HP	11659	2000	6172	19832	-0.5	4139	20365	24504	-6.2
Bio2CH4 - Adv CHP - BEV	11521	1927	5876	19324	-3	4117	20430	24547	-6
Bio2CH4 - CNG Car	11469	1915	6316	19700	-1.2	4106	22116	26223	0.4
Bio2CH4el - ThHP	11906	2331	5825	20063	0.7	4605	18767	23372	-10.5
Bio2CH4el - Ind CHP	11856	2276	6274	20406	2.4	4498	20834	25332	-3
Bio2CH4el - Ind CHP - HP	12045	2401	5330	19776	-0.8	4383	16488	20871	-20.1
Bio2CH4el - Ind CHP - BEV	11878	2298	4490	18667	-6.3	4572	16043	20615	-21.1
Bio2CH4el - DHN CHP	11864	2281	6274	20419	2.5	4500	20831	25331	-3
Bio2CH4el - DHN CHP - HP	12007	2377	5487	19871	-0.3	4374	17209	21584	-17.4
Bio2CH4el - DHN CHP - BEV	11638	2078	5418	19135	-4	4164	18829	22993	-12
Bio2CH4el - Dec CHP	11893	2355	6264	20512	2.9	4518	20788	25305	-3.1
Bio2CH4el - Dec CHP - HP	12025	2455	5516	19996	0.3	4312	17345	21657	-17.1
Bio2CH4el - Dec CHP - BEV	12067	2504	5031	19602	-1.6	4975	17512	22488	-13.9
Bio2CH4el - Adv CHP	12048	2319	6325	20692	3.8	4525	21068	25593	-2
Bio2CH4el - Adv CHP - HP	12265	2436	5436	20137	1	4381	16976	21358	-18.2
Bio2CH4el - Adv CHP - BEV	11814	2185	4676	18674	-6.3	4235	16896	21131	-19.1
Bio2CH4el - CNG Car	11803	2246	5977	20026	0.5	4482	20711	25193	-3.6
Pyro - Dec CHP	11544	1989	6627	20161	1.2	4118	22458	26575	1.7
Pyro - Dec CHP - HP	11599	2031	6375	20005	0.4	4127	21298	25425	-2.7
Pyro - Dec CHP - BEV	11509	1954	6225	19688	-1.2	4114	21479	25593	-2

D Profiles calculation

The appendix is complementary to Chapter 3. It provides supplementary information on the data and methodologies used for the calculation of the energy supply and demand profiles for the Swiss case study.

D.1 Calculation of the Design Reference Year (DRY).

The DRY is already introduced by Stadler et al. in [202]. Its calculation methodology is defined in the ISO 15927-4 [234]. The method presented in the ISO 15927-4 [234] is initially conceived for considering only weather data for the calculation of the DRY. However we have decided to also take into account energy related profiles. Six parameters are taken into consideration for the calculation of the DRY: hydro dams water inflow, hydro river electricity supply, global radiation, electricity demand, outdoors air temperature and wind electricity supply. The first four parameters are used as the primary parameters for selecting the best months to compose the DRY. The last two parameters are secondary parameters taken for deciding among the first months selection. Table D.1 contains the chosen years for each calendar month in the DRY. Data profiles from the 2009 to 2015 (both inclusive) are used to generate the DRY.

Table D.1 – Chosen year for each calendar month.

Month	*Jan.*	*Feb.*	*Mar.*	*Apr.*	*May*	*Jun.*	*Jul.*	*Aug.*	*Sep.*	*Oct.*	*Nov.*	*Dec.*
Year	2013	2009	2010	2014	2012	2015	2012	2013	2013	2011	2012	2013

In order to respect the natural weeks and ensure a smooth profile, the start of the month can be moved forwards or backwards in order to warranty that the first day of the following month corresponds to the next day of the week respect to the day of the week of the last day of the previous month. Figure D.1 depicts the procedure. It is specially important to have a correct electricity demand profile, since it is dependent on the day of the week.

	Year	Mo	Tu	We	Th	Fr	Sa	Su	…..	Th	Fr	Sa	Su	Mo	Tu
January	2013	28	29	30	31										
		31 DAYS													
February	2009				29	30	31	1	…..	26	27	28			
								28 DAYS							
March	2010									25	26	27	28	1	2
															31 DAYS

Figure D.1 – Example for merging the months for the creation of the TRY.

D.2 Heating signature for Switzerland

This section of the appendix contains the parameters of the Eq. 3.45.

Table D.2 – Heating signature parameters.

h_0	1123	[MW]
h_1	-63.21	[MW/°C]
T_0	17.06	[°C]
shift	1	[-]

Table D.3 – Hourly correction parameters for the heating.

1.438	1.077	1.289
1.486	1.250	1.423
1.254	1.192	1.276
1.246	1.060	1.144
1.374	0.890	0.994
1.409	1.122	0.748
1.216	0.887	0.731
0.965	0.925	0.825
0.913	0.890	0.917
0.865	0.907	0.869
0.799	0.886	0.835
0.770	0.801	0.831
0.943	0.912	0.908
0.837	0.850	0.968
0.915	0.944	1.185
0.921	1.116	1.203
0.953	1.295	1.208
0.890	0.956	0.949
0.764	0.852	0.814
0.749	0.763	0.680
0.752	0.801	0.895
0.938	1.195	1.061
1.126	1.069	0.903
1.403	1.345	1.343

D.3 Locations for new wind parks

Table D.4 – Locations for 18 new wind parks [15] with the closest MeteoSwiss weather station [10] and the correction factor between wind speed at 10m and 50m above ground [16].

Wind park location	Weather station	MeteoSwiss weather station code	$Speed_{50m}/_{10m}$
La Foilleuse	Aigle	AIG	1.14
Horntube	Boltigen	BOL	1.25
Chasseron I	Bullet / La Frétaz	FRE	1.52
Chasseron II	Bullet / La Frétaz	FRE	1.52
Montagne de Buttes	Bullet / La Frétaz	FRE	1.52
Crêt Meuron	Chasseral	CHA	1.10
Frémont	Chasseral	CHA	1.10
Les Bugnenets	Chasseral	CHA	1.10
Vue des Alpes	Chasseral	CHA	1.10
Collonges	Evionnaz	EVI	1.21
Grimselpass	Grimsel Hospiz	GRH	1.42
Männlichen	Jungfraujoch	JUN	1.22
Grande Sagneule	La Brévine	BRL	1.11
Col de la Givrine	La Dôle	DOL	1.13
Sonnailley	La Dôle	DOL	1.13
Alp Nova	Piz Martegnas	PMA	1.05
Bischolpass	Piz Martegnas	PMA	1.05
Riddes	Sion	SIO	1.23

D.4 Private car driving profiles

Tables D.5 to D.8 contain the usage profiles for the 40 typical cars. The “Begin" and “End" rows indicate the starting and finishing hour of the trip, respectively. In the case of leisure, some cars are assumed to do only on way trip in the day, in order to take into consideration the trips for reaching the second residence during the weekend. The “weight" row provides the information on the percentage of mobile people that each car represents. The data on the tables are used to generation the percentages of mobile people in cars by reason in figure D.2, which are presented and compared to the curves reported in [7]. The calculated curves are mixed taking into consideration the percentages reported in table D.9. That provides the normalised vehicle usage profiles by type of day. The computed profiles by day are compared to the profiles generated with data from the vehicle counters on roads [8]. The mid-day discrepancies could be explained by the fact that the counters may not record some of the mid-day trips since most of the counters are located in high-traffic roads communicating urban areas, not within urban areas. That is combined to the fact that at mid-day time some trips are done within the urban area. Finally, the normalised curves for each type of day are combined to form the annual hourly cars usage curve. For this last calculation is necessary to know how does each type of day compares to each other in terms of vehicles usage. This is done using the maximum value of the annual average of the hourly counted vehicles for each type of day: 673959 (week day), 536533 (Saturday) and 532296 (Sunday).

Table D.5 – usage profiles and mobile-people percentage for work cars.

		Work Car									
		1	2	3	4	5	6	7	8	9	10
Begin 1	[h]	8	6	6	5	6	12	7	6	5	7
End 1	[h]	9	7	7	6	7	13	8	7	6	8
Begin 2	[h]	18	15	13	12	16	20	19	14	11	17
End 2	[h]	19	16	14	13	17	21	20	15	12	18
Weight	[h]	3.1	1.64	1.97	1.69	3.01	1.11	1.72	1.41	1.7	4.79

Table D.6 – usage profiles and mobile-people percentage for education cars.

		education Car									
		1	2	3	4	5	6	7	8	9	10
Begin 1	[h]	6	8	7	7	6	6	6	9	11	10
End 1	[h]	7	9	8	8	7	7	7	10	12	11
Begin 2	[h]	18	15	13	12	16	20	19	14	11	17
End 2	[h]	17	19	18	14	13	15	17	18	22	20
Weight	[%]	0.14	0.19	0.22	0.06	0.05	0.03	0.06	0.09	0.08	0.09

Table D.7 – usage profiles and mobile-people percentage for shopping cars.

		Shopping Car									
		1	2	3	4	5	6	7	8	9	10
Begin 1	[h]	8	11	10	8	9	9	10	13	11	10
End 1	[h]	9	12	11	9	10	10	11	14	12	11
Begin 2	[h]	11	14	14	12	15	18	16	17	16	12
End 2	[h]	12	15	15	13	16	19	17	18	17	13
Weight	[%]	1.50	1.67	1.56	1.20	2.88	1.53	1.54	2.94	1.86	1.18

Table D.8 – usage profiles and mobile-people percentage for leisure cars.

		Leisure Car									
		1	2	3	4	5	6	7	8	9	10
Begin 1	[h]	10	9	12	14	0	11	18	8	16	13
End 1	[h]	11	10	13	15	1	12	19	9	17	14
Begin 2	[h]	15	20	19	17	5	0	0	0	0	0
End 2	[h]	16	21	20	18	6	0	0	0	0	0
Weight	[%]	3.64	2.89	3.79	4.36	0.31	3.89	4.74	2.26	4.36	3.50

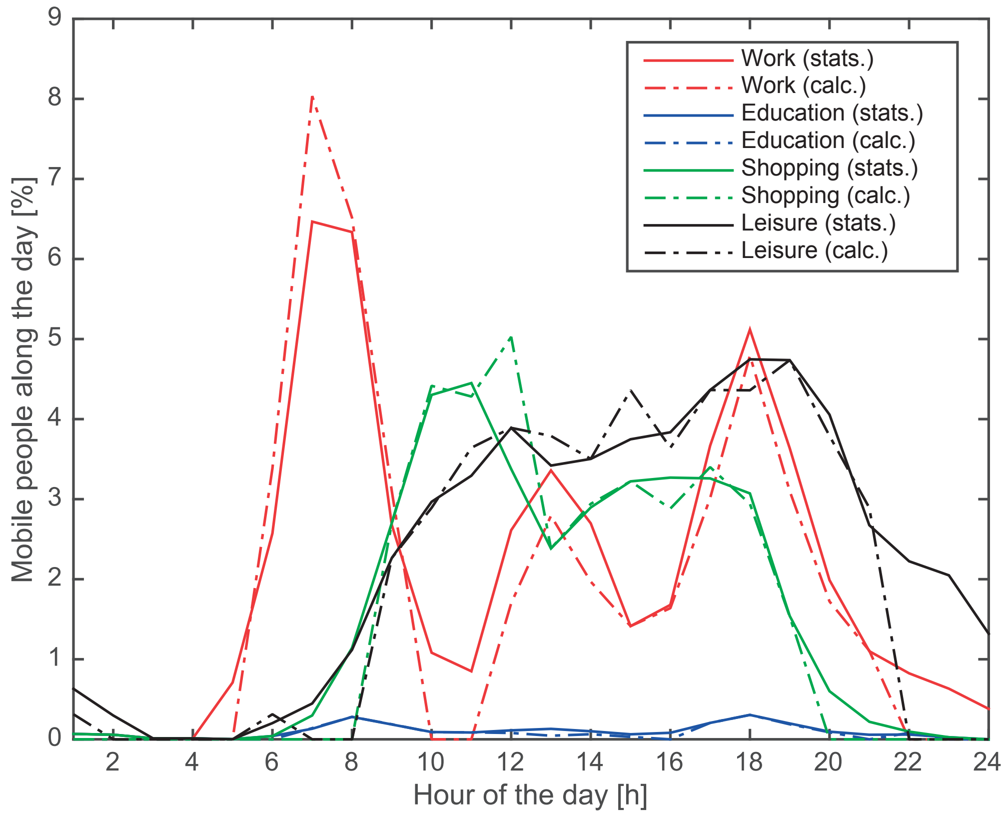

Figure D.2 – Percentages of mobile people by car by reason. Each reason has the calculated profile considering the vehicles utilization curves and their weight, and the profile from [7].

Table D.9 – Mobility reason by type of day.

	Mobility reason			
	Work	education	Shopping	Leisure
Mon.-Frid.	37.2	8.1	16.3	38.4
Saturday	6.7	2.2	20.0	71.1
Sunday	4.4	1.1	4.4	90.1

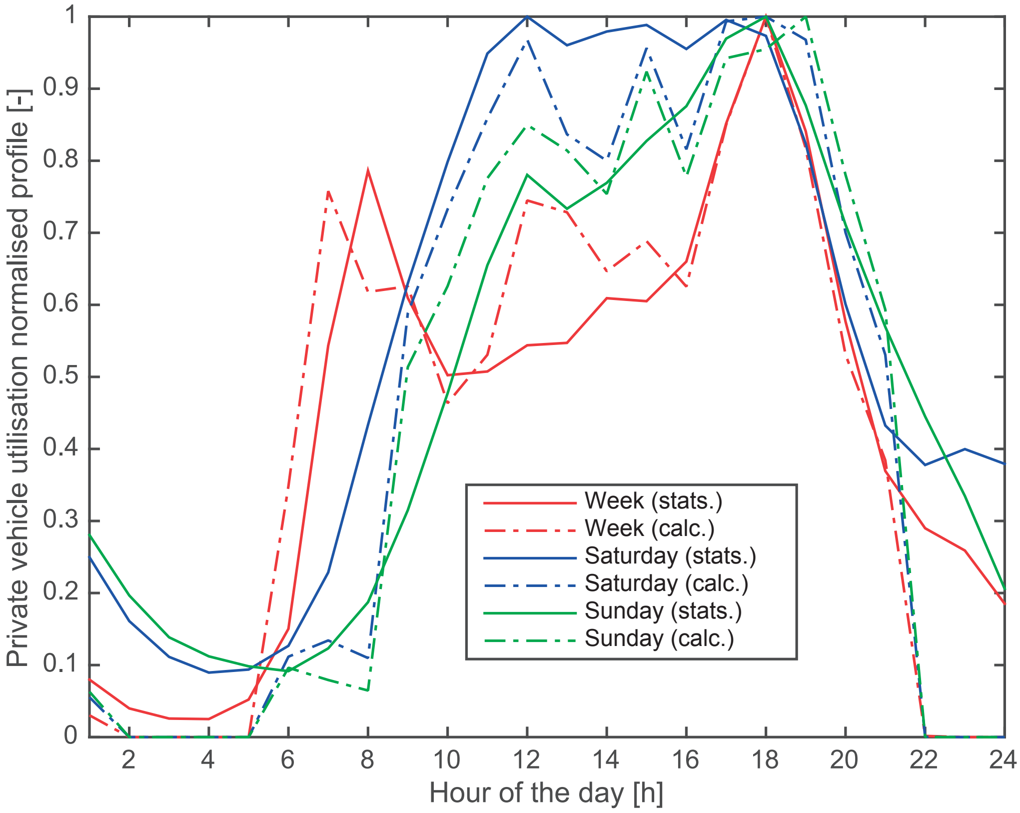

Figure D.3 – Normalised vehicle usage by type of day. Each type of day has the calculated profile, and the profile generated from the vehicle counters data [8].

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PERSONAL INFORMATION

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Nationality	Spanish
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WORK EXPERIENCE

2014 - present — **PhD Assistant,** Industrial Process and Energy Systems Engineering group (IPESE) and Energy Center of the École Polytechnique Fédérale de Lausanne (EPFL)

- Development of online tools for familiarising citizens and decision-makers to the energy transition.
- Energy policy recommendations based on modelling and optimisation methods.

2013 — **Research Assistant,** IPESE

Design of integrated 1st and 2nd generation ethanol production processes.

2012 — **Intern,** Huntsman, Advanced Material Division, Monthey, Switzerland
Energy efficiency project. Proposed improvements able to save up to 30% of the energy bill.

2008 – 2010 — **Intern,** Ridel Assessors SL, Barcelona, Spain
Preparation of accounting annual reports.

2005 - 2007 — **Youth Centre Coach,** Esplai Santa Engracia, Barcelona, Spain

SELECTED PROJECTS

Swiss-Energyscope — Development of an online platform dedicated to the Swiss energy transition, including an energy calculator, an online course and a 100Q&A book. Personal role in the project: Energy calculator main developer and scientific support. http://energyscope.ch/

Vaud-Energyscope — Adaptation of the Swiss-Energyscope online calculator to the Canton of Vaud: reference tool for the development of the cantonal energy strategy.

STORE&GO — European-H-2020 project. Design and construction of three innovative Power to Gas (PtG) electricity storage concepts at locations in Germany, Switzerland and Italy. Personal role in the project: Analysis of the environmental impact of the technology. https://www.storeandgo.info/

BIOSWEET — Development of the Swiss national strategy for biomass use in energy services.

Wood energy strategy - Vaud — Development of the Cantonal strategy for wood use in energy services. Project leaded by QUANTIS (global leader on sustainability studies). Personal role in the project: Scientific and technology advisor.

EDUCATION

2014 - 2018 — **Ecole Polytechnique Fédérale de Lausanne (EPFL), Lausanne, Switzerland.** PhD in Energy Modelling and Optimisation

2016 — **Commission for Technology and Innovation (CTI), Switzerland.** Entrepreneurship Training, Business Concept

2007 - 2012 — **Barcelona School of Industrial Engineering (ETSEIB), Barcelona, Spain.** BSc and MSc in Industrial Engineering (1 year exchange at EPFL)

SELECTED PUBLICATIONS

PhD thesis — **Scenario modelling and optimisation of renewable energy integration for the energy transition,** 2018, EPFL.

Book — Contributing author. **Les enjeux de la transition énergétique suisse. Comprendre pour choisir: 100 questions-réponses.** Presses polytechniques et universitaires romandes.

Journal article — **Strategic energy planning for large-scale energy systems: A modelling framework to aid decision-making.** Energy, 2015.

Journal article — **Optimal use of biomass in large-scale energy systems: Insights for energy policy.** Energy, 2015.

LANGUAGES

Mother tongue — Spanish
Catalan

Other languages — English (fluent speaking, writing and reading)
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