Joint Activity Scenarios and Modelling

LONG-TERM ENERGY TRANSFORMATION PATHWAYS

INTEGRATED SCENARIO ANALYSIS WITH THE SWISS TIMES ENERGY SYSTEMS MODEL

Evangelos Panos[a]
Tom Kober[a]
Kannan Ramachandran[a]
Stefan Hirschberg[a]

[a] Paul Scherrer Institute

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Chapter 1

Extended Executive Summary

Key Messages

Achieving the Swiss energy and climate goals would require scaling up clean energy technologies

The ambition to reach the net-zero CO_2 emissions[1] objective by 2050 requires a radical transformation of the way energy is supplied, transformed and used. It is necessary to deploy solar PV, electric and hydrogen cars, heat pumps, and energy savings measures on a far greater scale and more rapidly than today. The installed capacity of solar PV power needs to double almost every decade from now to 2050. The private car fleet would need to be mostly based on electric drive trains by 2050, which means one in every three new car registrations must be electric by 2030. The deployment of heat pumps needs to accelerate in the services and residential sectors so that, by 2050, heat pumps would cover close to three quarters of the space and water heating demand in buildings. Also, it would be necessary to reap efficiency gains by rolling out energy saving measures via accelerated renovation.

Electricity – a key energy carrier in reaching net-zero emissions

In achieving the net-zero ambition, the total electricity consumption of the energy end-use sectors (industry, residential, services and transport) increases by 11 TWh in 2050 from 2019 levels. This growth is mainly driven by using electricity to power cars, buses, and trucks. By also accounting the electricity used for producing hydrogen and synthetic e-fuels consumed mainly in transport, the total domestic electricity consumption increases by around 20 TWh between 2019 and 2050. In the stationary sectors, electricity becomes increasingly important as heat pumps are deployed more widely. After 2030, efficiency gains offset increased consumption, and the stationary sectors show a plateauing electricity consumption. Electrification and efficiency improvements enable a reduction of the final energy consumption per capita by 55% in 2050 compared to 2000 levels, slightly higher than the long-term target of the Swiss Energy Strategy.

Electrification alone cannot decarbonise the entire energy system

Hydrogen penetrates industry and mobility sectors for applications where the direct use of electricity is challenging or associated with very high costs. Long-distance public and freight road transport and heavy industry, are hardest to decarbonise and provide prospects for new hydrogen technologies. About 11 TWh of hydrogen (half of it produced via electrolysis) are used directly, or indirectly for

[1] The analysis considers energy-related CO_2 emissions and CO_2 emissions from industrial processes and product use. Today, these emissions represent around 80% of the entire Swiss green house gas inventory. The analysis does not consider emissions from international aviation, agriculture (other than emissions from fuel combustion), land-use, land-use change and forestry (LULUCF), waste (other than emissions from waste incineration).

producing synthetic fuels, in 2050. Imported biofuels and synthetic fuels of about 10 TWh in total are also needed by 2050, mainly in the long-distance passenger and freight road transport.

Carbon capture and bioenergy play an important role

Achieving the net-zero goal in a cost-efficient way would require capturing about 8.6 Mt CO_2 from the energy system in 2050. In this regard, capture, utilisation and storage of CO_2 is a crucial mitigation option to reach deep decarbonisation. About half of the captured emissions are from negative emissions technologies such as bioenergy with carbon capture and direct air capture. Bioenergy conversion with carbon capture can become vital not only for removing CO_2 from the atmosphere but also for producing hydrogen which is also directly used to replace fossil fuels. Failing to harvest the remaining exploitable sustainable potential of bioenergy would entail high climate change mitigation costs. Also, if storing captured CO_2 in Switzerland is a challenge, access to international CO_2 transport and storage infrastructure would be essential to avoid a drastic increase in mitigation costs.

Fostering innovation in electrification, hydrogen, bioenergy and CCS is essential

More than two-thirds of the cumulative emissions reduction required to achieve the net-zero emissions goal stem from technologies that are already commercially available or under demonstration. In this regard, long-term policy targets need to be backed up by detailed, clean energy technology strategies involving measures tailored to local infrastructure and technology integration needs.

Achieving the net-zero ambition is technically feasible but requires coordinated efforts across all sectors and access to international energy markets in order to limit the associated costs

From a technology point of view, there is a general understanding of the new energy and industry applications needed to attain deep CO_2 emissions reductions. But energy companies and industry would need clear long-term strategies. Also, the engagement and choices made by consumers for certain products and services, as well as the acceptance of new technologies, will be crucial. Transforming the entire energy system will require progress across a wide range of technologies and action across all sectors, not just electricity. If key technologies for the transition fail to scale up, especially renewables and CCS, e.g. due to financial risks or social acceptance issues, then the feasibility of reaching the net-zero target would be challenged, or the target would only be achieved at higher costs. The decarbonised energy system of the future requires zero-carbon energy carriers (electricity, biofuels and e-fuels), access to the corresponding transport and distribution infrastructure, as well as the possibility to import clean fuels and electricity. Limited import opportunities or bottlenecks in transmission and distribution infrastructures can result in substantially increasing mitigation costs. Further, the climate target would be at risk if clean fuel and electricity imports are not available at all.

Cost-efficient deep decarbonisation needs all the options to be on the table

The cost of the transition of the Swiss energy system to net-zero emissions in 2050 depends on the resource availability, social acceptance, technology progress, and the level of integration of local, national and international markets. It is also affected by the mitigation level already achieved in the reference scenario, against which the policy cost is calculated. The reference scenario in this analysis arrives at around 26 Mt CO_2/yr. emissions from the energy system and industrial processes in 2050. The analysis of an extensive set of variants assuming different developments in the aforementioned factors reveals a large cost range, which indicates the uncertainty surrounding the abatement effort.

The lowest mitigation cost occurs when decarbonisation can be achieved based on the availability of all possible least-cost mitigation options and weather research and innovation succeed in improving the performance and reducing the costs of low-carbon technologies. Under favourable conditions, the complete decarbonisation of the energy system requires cumulative system costs of 59 billion CHF_{2010} from 2020 to 2050 discounted at a 2.5% social discount rate (or, 97 billion CHF_{2010} undiscounted)[2].

The highest mitigation costs occur when the transition to a low-carbon economy faces fragmented national and international policies, low cooperation and market integration, a low exploitation rate of renewable resources, slow technical progress and limited social acceptance. In such an extreme case, the cost can be as high as 257 billion CHF_{2010} from 2020 to 2050 discounted at 2.5% discount rate (426 billion CHF_{2010} undiscounted).

The core net-zero scenario evaluated in this study (the *CLI* scenario) shows cumulative costs of 97 billion CHF_{2010} over the period of 2020-2050, discounted at 2.5%, or 163 billion CHF_{2010} undiscounted. The transport sector has the lion's share in the incremental investment needs, with the additional cumulative discounted investment expenditure in the mobility sectors alone accounting for 46 billion CHF_{2010}. In terms of average per capita cost per year, this translates to 330 CHF_{2010}/yr. discounted, or 540 CHF_{2010}/yr. undiscounted from now until 2050. By considering the whole set of assessed variants, the average per capita cost per year to reach net-zero emissions by 2050 ranges from 200 to 860 CHF_{2010}/yr. discounted, or from 330 to 1430 CHF_{2010}/yr. undiscounted over the period of 2020-2050. It should be noted that the per capita costs are averaged over the investigated time horizon until 2050, which is characterised by a fundamental transformation of the energy system and new technology and fuel mixes. The associated annual policy costs increase exponentially over the projection period, meaning that by 2050 we have built a more expensive energy system, which will require endured investments and expenditures for low carbon energy supply and demand also beyond 2050.

Transition enablers and challenges

The transition to the net-zero emissions goal needs actions across all sectors of the energy system. The timing of the actions is critical, and solutions need to be developed on a large scale.

In the **buildings sector**, the rate of renovation needs to be significantly increased, and energy-efficient technologies in heating and electric uses need to be deployed at a large scale. However, current pay-back times make the investment in renovation and new heating equipment financially unattractive for owners and landlords, also because of the "split incentives" issue (Economidou and Bertoldi, 2015). Besides technological development, there is also the challenge to make consumers more active participants in the energy markets and encourage them to invest in energy savings and storage. Smart technology and digitalisation would need to be integrated in order to reap the benefits of the transition in a cost affordable manner. Current technological progress has already made certain solutions easily available to consumers (e.g. better control of indoor temperatures) and enabled a more rational use of the energy than in the past. Still, the widespread uptake of automation and digitalisation depends on its ease of use, on remaining consumer behaviour biases, and on infrastructure improvements that currently have long pay-back periods. To this end, targeted policies would be needed to lift these financial and behavioural barriers in the use of cutting-edge IT solutions and enable smart and efficient use of energy.

In **industry**, challenges related to cost and technology deployment impact the transition. The required emissions reductions cannot be achieved solely with today's Best Available Technologies; they are closely linked with the development of low carbon technologies, increased electrification of pro-

[2] 1 CHF_{2010}=0.98 CHF_{2019} due to the persistent negative inflation in the last four years

cess heat, use of biomass/hydrogen and CO_2 capture. In this regard, the shift away from fossil fuels would make the sector increasingly electricity-intensive. Moreover, the implementation of decarbonisation policies also implies access to adequate infrastructure to support electrification, the use of zero-carbon fuels, material efficiency, sustainable and optimised material flows supporting circular economy and "industrial symbiosis" (Obrist et al., 2021, Wyns, T., Khandekar, G., Robson, 2018). The analysis suggests that the speed of penetration and deployment of key decarbonisation technologies in all industrial sectors is critical. In order to facilitate this without jeopardising the competitiveness of the Swiss industry, roadmaps should be developed in combination with new market designs and a policy framework supporting the required changes. To this end, the timely replacement of ageing infrastructure and assets with alternatives that are more efficient and more compatible with the decarbonisation targets can offer an opportunity. Such an opportunity can be increasingly attractive to investors if they receive suitable long-term price signals from markets and policies.

In the **mobility sector**, road transport would need to achieve the highest emissions reductions across all sectors. The growing momentum for electric vehicles for private cars and light-duty vehicles needs to be maintained and amplified, as well as to be supported and complemented with other zero-carbon options, e.g. hydrogen fuel cells, which should become available on a larger scale towards mid-century. Biofuels and synthetic e-fuels can represent a promising alternative, because of their advantage in their direct use in conventional engines without altering existing fuel distribution infrastructure. However, the transport modes where biofuels and mainly e-fuels would be deployed need to be carefully considered, as the use of biofiels is associated with land-use and food security issues, and e-fuels require large amounts of electricity. Besides, the life cycle emissions of e-fuels depends on the source of carbon used for their production. Moreover, there is also considerable uncertainty regarding production costs and the deployment of carbon capture options connected to synfuel production. Aside from the technological developments in transport, stronger integration of the mobility sector with the rest of the energy system is also essential. Vehicles can be turned into multi-purpose assets via smart charging and discharging that enable new consumer services, which generate cost savings for vehicles' owners and provide flexibility to the energy system supporting the transition (Panos et al., 2019a, Liu et al., 2016). New societal developments and consumer choices, automated mobility and mobility as a service can better support this integration and can be an important part of the decarbonisation agenda.

Bioenergy is a key energy carrier towards net-zero. It would be necessary to foster bioenergy projects and develop the infrastructure for bioenergy distribution (e.g. biogas) further, as the demand for bioenergy doubles between 2015 and 2050 under a cost-optimal decarbonisation strategy. Renewable waste, agriculture and forest residues that are widely used today are not sufficient to satisfy the additional future demand. The exploitation of the sustainable potential of manure and forest wood would also be required. To unlock scale effects and reap the environmental benefits that manure offers, financial obstacles related to its use for biogas need to be overcome, e.g. via subsidies, certificates or co-fermentation with higher-energetic sources, and technical barriers related to its collection must be lifted, e.g. by collecting it from multiple and closed-together farms for usage in a single facility (Burg et al., 2019). The availability of forest wood is largely based on the intensity of forest management and also influenced by conflicting non-energetic uses including eco-services provided by the forest per se, such as soil protection, climate regulation, pollution and water control, recreational activities. (Thees et al., 2020).

Hydrogen produced from low-carbon sources gains growing importance in a climate-neutral Swiss economy by 2050. As such, strong climate policy is a prerequisite for hydrogen deployment. In addition, the future success and timing of a hydrogen economy are highly dependent on technological developments and targeted measures. The mid-term horizon until 2030/40 is crucial for the wider deployment of hydrogen in the long term. As investment cycles in the energy conversion sector run for about two to three decades and the time needed for new energy technologies to penetrate existing markets is long, various forms of support will be required to help stimulating demand and supply of clean hydrogen. During the transition phase of the hydrogen infrastructure development, policy support should prevent stranded assets in hydrogen technology that do not meet long-term environmental criteria. To foster innovation and investor confidence, policy needs to provide stable long-term signals (such as rigid climate goals) to create demand for hydrogen while mitigating the investment risks. The creation of hydrogen demand can be facilitated by stringent emission and efficiency standards for vehicles and buildings or market-based mechanisms such as fossil fuel taxation. Industrial clusters may offer good opportunities for low-carbon hydrogen deployment and could be stimulated by a reinforcement of the emission trading scheme and carbon intensity reduction goals.

Power-to-X technologies also become an important element of the transition, but wide-scale investment in these is not yet economically viable. Literature has identified key barriers hindering the deployment of Power-to-X, which can be grouped into the following categories (Kober et al., 2019, GIE, 2019): a) market design barriers related to the role of Power-to-X under sector coupling; b) regulatory barriers that include the usage and access of networks and infrastructures, as well as fiscal and taxation issues; c) technical barriers including the definition of standards related to operational issues among neighbouring countries; d) governance barriers impeding planning and collaboration among the energy sectors that need to work together in sector coupling, i.e. impeding coordination and efficient interaction among the electricity, gas and hydrogen transmission and distribution infrastructures. The analysis also suggests that the ability to combine revenues from different markets such as ancillary services, heat, hydrogen, synthetic fuels, oxygen and CO_2 certificates, is important for the successful market integration of Power-to-X. If stringent climate change mitigation policy is implemented and the vast potential of new renewable energy is accessible, Power-to-X technologies can contribute to a cost-efficient and reliable energy supply structure and reduce CO_2 emissions.

The **electricity supply** shifts from demand-following to largely weather-driven production and faces the need for additional **flexibility**. About 45% of electricity generation in the net-zero scenario originates from variable renewable energy sources, mainly solar PV. There is a significant increase in power generation capacity in consumption areas, which means that spatial planning could be an important challenge requiring engagement with consumers and local authorities. The need for flexibility would also require a market opening, which entails a variety of opportunities for centralised storage (including new solutions based on hydrogen and e-fuels), for flexible consumers (individual ones or those collectively offering their capacities through aggregators) with decentralised storages and smart demand technologies, and for electricity producers who can be integrated via peer-to-peer trading. The regulatory framework needed to support this major change in the electricity market structure will require close cooperation across Transmission and Distribution System Operators, in order to overcome potential challenges related to the wide realisation of the new electricity supply paradigm.

The **district heating** network operators also have an essential role in the energy transition because district heating systems provide flexibility for the integration of different renewable energy sources. By 2050 district heating systems are largely based on renewable energy sources and rely on a range of options such as solar, biomass, geothermal, and heat storages. This implies a transformation of the network itself, building on smart integration of energy systems as well as prosumers' involvement. In this regard, district heating networks need to be embedded in an overall plan across multiple infrastructures (including electricity and gas grids) with coordination between local authorities and service providers, as well as alignment with other infrastructure developments (BRE, 2013).

Negative emission technologies are essential for the transition towards a net-zero CO_2 energy system in order to offset the remaining emissions that are most difficult to abate in transport, in industry and from waste management. Maintaining, or even increasing, carbon sinks related to land-use and forestry management is important. Still, alone they are not sufficient to provide the required emission removals while their deployment also depends on developments such as changing consumers' dietary preferences (Smith et al., 2015). Thus, CO_2 removal technologies need to be part of the solution. Although all components of these technologies are known and deployed at commercial or demonstration scale, there are barriers hindering their larger deployment. These include the cost of CO_2 capture and storage, the social acceptance for onshore CO_2 storage, and concerns related to the integrity of CO_2 storages and the perceived risk of carbon leakage. In Europe, there are projects that store CO_2 offshore below the seabed, for which public acceptance is typically higher than for onshore storage. There is a discussion in Europe on the capture of CO_2 and its storage at different sites and possibly different countries with potential offshore storage capacities (EC, 2018). Therefore, if storing CO_2 in Switzerland is uncertain or limited, Switzerland would need to obtain access to infrastructures transporting CO_2 abroad and also participate in establishing a consistent framework to account correctly for emissions removals. Active involvement of Switzerland in the development of this infrastructure and in international agreements for delivery contracts would also be needed.

An **affordable transition to decarbonisation** is built around three main pillars. The first pillar is the exploitation of the remaining sustainable domestic renewable energy potential. This includes not only the solar PV systems but also bioenergy, wind and geothermal. Of critical importance is keeping hydro at least at the current level, and also securing access to the sustainable bioenergy potential that could be used to deliver negative emissions. The second pillar is the integration of energy markets, especially those involving the trading of new energy carriers such as hydrogen and synthetic fuels. While it is technically feasible to develop domestic synthetic fuels and e-fuels, it is not always the most cost-effective option. The third pillar is technology innovation and R&D worldwide on low carbon technologies, to reduce their costs and improve the overall performance. The transition to a low carbon energy economy can be greatly accelerated by technological progress and also circular economy practices that reduce the cost of materials, renovation costs and costs of implementing energy conservation schemes.

In this regard, the **financial sector** is widely acknowledged in the literature as a key enabler of the transition to decarbonisation (EC, 2018). Important is to avoid stranded assets that lead to losses for companies and financial institutions. To achieve this, re-orientation of capital to energy efficiency and renewable technologies needs to be consistently done across the real economy and should integrate physical risks and intangible environmental, societal and governance factors in asset pricing. Private finance will have to account for the bulk of investment needs, and it would be necessary that investors support the transition. To this end, private investors should consistently have the option of investing in zero- or low-carbon assets, climate and environmental risks should be included in economic and financial evaluation of assets, and long-term and transparent signals should be given to companies and financial institutes related to the energy and climate objectives.

Modelling approach to analyse energy transformation pathways

This analysis is based on the integrated modelling framework of PSI, which was further developed and extended within the collaboration of the Swiss Competence Centre of Research (SCCER) Joint Activity Scenarios and Modelling (JASM), SCCER Supply of Electricity (SoE), SCCER Efficient Technologies and Systems for Mobility (Mobility), SCCER Biomass for Swiss Energy Future (Biosweet) and SCCER Heat and Electricity Storage (HaE), and other projects.

The Swiss TIMES Energy systems Model (STEM) has been applied in this analysis, representing more than 90 energy end uses and hundreds of technologies. STEM is based on the IEA TIMES modelling framework (Loulou et al.)[3]; it combines technical engineering with economic approaches and allows for the analysis of transition pathways in an integrated framework. TIMES is an open-source and fully documented framework, and it is also used by the IEA in its flagship publication series Energy Technology Perspectives. STEM is operated by the Energy Economics Group of the Laboratory for Energy systems Analysis (LEA) at PSI and informed by the detailed technology databases of LEA's Technology Assessment Group.

Within the SCCER JASM, supported and informed by the SCCERs SoE, Mobility, BioSweet and HaE, the database of STEM was greatly improved while the model was further extended regarding the detail of the representation of the energy system. There was a successful and fruitful flow of knowledge and data between the LEA team and the teams involved in the aforementioned SCCERs, which in the end led to the improvement of not only STEM but also the modelling frameworks of other involved teams.

The analysis with STEM seeks to assess the challenges and opportunities associated with a rapid, clean energy transition. This report covers the dynamics of the transition of all areas of the energy system and provides insights regarding the sectors' transformation pathways and the associated costs.

Using the STEM scenarios

The scenarios quantified by STEM should not be considered forecasts. Rather they are coherent, internally consistent descriptions of a possible future state of the energy system. Unlike forecasts and conditional projections, the STEM scenarios focus on the wider context in which the energy system is evolving. They describe what might happen, rather than what decision-makers expect or think should happen. As such, the scenarios quantified with STEM consist of a set of coherent assumptions, based on storylines. They also explore different parametric uncertainties under a "what-if" framework. The "what-if" scenario analysis provides insights into the impact of different policy options and potential energy technology/infrastructure targets for policy support.

In a STEM analysis, a baseline (or reference) scenario is generated first by running the model in the absence of policy constraints. The results from the baseline scenario are not always totally aligned to national forecasts, mainly because STEM optimises the energy system by providing the least cost solution. By imposing one or more policy constraints on the model, e.g. the maximum amount of CO_2 emissions allowed to be emitted in a given year, and by contrasting the results of this policy scenario

[3]The TIMES modelling framework is open-source and it can be downloaded from https://github.com/etsap-TIMES/TIMES_model

to the results of the baseline, the different technology choices can be identified that comply with the policy constraint(s) at least cost.

The main purpose of the scenarios is to provide insights to decision-makers and stakeholders on meeting the challenges of a cost-effective transition to a low carbon energy system with net-zero emissions. As a coherent set of plausible future states, they provide a framework to aid decision support in clarifying strategic choices, identifying alternative policy options, designing cross-cutting sectoral policies for achieving underlying goals featured in each scenario, exploring the interlinks and interactions between the different goals to enhance policy cohesion, and discovering new business opportunities the energy transition offers.

Chapter 2

Modelling framework, scenarios description and main assumptions

2.1 The Swiss TIMES Energy systems Model – STEM

The Swiss TIMES Energy systems Model (STEM) (Kannan and Turton, 2014) has a long-term horizon (2010-2100) with 288 intra-annual operating hours (four seasons and three average days per season, a working day, a Saturday and a Sunday/Holiday, with 24h resolution). It covers the whole Swiss energy system with a broad suite of energy and emissions commodities, technologies and infrastructures, from resource supply to energy conversion and use in 17 energy demand (sub-)sectors. STEM aims to supply energy services at a minimum energy system cost (more accurately at a minimum loss of surplus) by simultaneously making equipment investment and operating, primary energy supply, and energy trade decisions (figure 2.1). In STEM, the quantities and prices of the various commodities are in equilibrium, i.e. their prices and quantities in each time period are such that suppliers produce exactly the quantities demanded by consumers. This equilibrium has the property that the total surplus is maximised.

Within JASM, we focus our analysis on the developments until 2050. The horizon 2020-2050 is split into 4 periods, which are represented by the milestone years 2020, 2030, 2040 and 2050. Each milestone year represents a point in time where decisions are taken by the model, e.g. installation of new capacity or changes in energy flows. The periods do not have the same length. The first period is 2017-2023 (duration 7 years, milestone year 2020), the second period is 2024-2036 (duration 13 years, milestone year 2030), the third period is 2037-2044 (duration 8 years, milestone year 2040) and the last period is 2045-2055 (duration 11 years, milestone year 2050). Each year in a given period is considered to be identical, except of for the cost objective function, which differentiates between payments in each year of a period. Therefore, when we report cumulative energy system costs between 2020 and 2050, we consider in the calculation the time horizon from 2017 to 2050, i.e. we do not include the last 5 years of the last period of the model.

STEM is particularly suited to the exploration of possible energy futures based on contrasted scenarios. Scenarios, unlike forecasts, do not presuppose knowledge of the main drivers of the energy system. Instead, a scenario consists of a set of coherent assumptions about the future trajectories of these drivers, leading to a coherent organisation of the system under study.

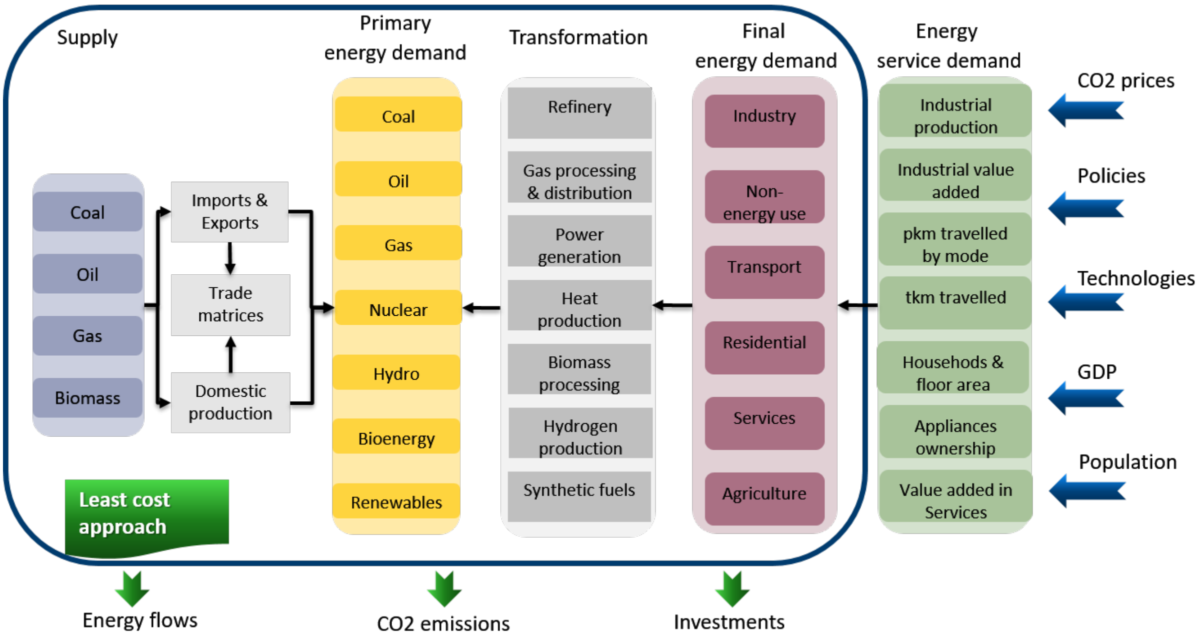


Figure 2.1: *Overview of STEM's structure and concept*

A scenario builder must therefore carefully test the assumptions made for internal coherence, via a credible storyline. A complete scenario consists of four types of inputs: energy service demands, primary resource potentials, a policy setting, and the description of a set of technologies.

The main energy demand sectors in STEM are industrial, residential, commercial and transport. The industrial sector is further divided into seven major subsectors, with the following energy end-uses (energy service demands): space heating, water heating, process heat, lighting, air conditioning, electrical equipment, motors and other uses. Different types of buildings are distinguished for the residential sector, depending on their construction year and size. The energy uses in the residential sectors include space heating, water heating, air conditioning, electronic equipment, appliances, cooking, lighting, washing and refrigeration. The transport sector in STEM includes passenger and freight transport. The model distinguishes between different modes of transport such as private transport (cars and two-wheelers), public passenger road transport, freight road transport, passenger and freight rail transport, domestic and international aviation.

A salient feature of the model is the hourly profiles of the different end-uses (e.g. driving, hot water, cooking, space heating, process heating, lighting etc.). The detail description of the profiles, together with their data sources, are described in (Kannan and Turton, 2014). While the profiles of the energy service demands are given exogenously, the fuel consumption required to satisfy the needs can be endogenously shifted via, e.g. the deployment of storages, demand response and management options. Hence, STEM allows for a decoupling in time between fuel consumption and the use of the generated energy. It follows that the future hourly profiles of the different loads for the various end uses (for example electricity loads, heat loads, fuel consumption for mobility) are endogenous in STEM.

The transformation sector includes the conversion of fuels, and power and district heat generation. The model includes options for producing synthetic fuels, and it has an explicit representation of the storage, transport and distribution required for the secondary energy carriers. A particular emphasis was given to the electricity sector to be able to address systems with high shares of variable renewable energy in combination with large fossil or nuclear power plants. Four electricity grid transmission and distribution levels are represented, from very high to low voltage, to which different power plant and storage options are connected (Panos and Kannan, 2016, Vögelin et al., 2016). Technical operating constraints for the hydrothermal power plants are approximated via a continuous relaxation of the unit commitment problem, in which identical or similar production units form technology clusters (Panos and Lehtilä, 2016). Such an approximation should not be used to analyse actual system operation, but it is valuable for including short-term operation into long-term planning. It also allows for the computationally efficient representation of a range of operating constraints, such as ramping rates, minimum stable operating levels, part-load efficiency losses, minimum online and offline times and start-up costs, without the complexity imposed by mixed-integer programming. STEM also includes an ad-hoc representation of the electricity grid transmission topology with fifteen grid nodes. Seven Swiss regions are represented as a single node each. Also, each of the four existing nuclear power plants and each one of the four neighbouring countries is also represented as a single node. A power flow model (Schlecht and Weigt, 2014) is employed to aggregate the detailed electricity transmission grid into the 15 nodes and 319 bi-directional lines included in STEM (Fuchs et al., 2017, Lehtilä and Giannakidis, 2013). Investments and disinvestments are determined in STEM endogenously, including endogenous options for lifetime extension and retrofitting of existing capacities. Power plants can be retired before the end of their technical lifetime when they have higher fixed or operating costs than the investment cost of new technology (Lehtilä and Noble, 2011). Electricity storage options are also included in the model and are subject to energy buffer dynamics and limited lifecycles. A storage system is defined in terms of its discharging power and energy storage capacity. Asymmetrical charge and discharge power ratings are allowed.

STEM also accounts for the variation of renewable energy availability, demand, and of the residual load curve. Following the methodology presented in (Lehtilä et al., 2014), and based on the stochastic variability of electricity supply and demand, the model includes two constraints for ensuring the security of the electricity system. The first constraint defines the minimum available storage capacity to cope with the downward variation of the residual load curve and the upward variation of the non-dispatchable generation. The second constraint defines the minimum dispatchable capacity (including storage) to cope with the upward variation of the residual load curve and downward variation of the non-dispatchable generation, i.e. it ensures sufficient peak load capacity. The requirements for primary and secondary reserve capacity are endogenously modelled with a representation of the markets for ancillary services (Panos et al., 2019b). The provision of reserve capacity is categorised into positive capacity, an, i.e. capacity that can be brought online to increase supply, and negative capacity, an, i.e. capacity that can be set to offline to reduce the excess of supply. Despite the reserve provided from power generation options, the provision of the positive reserve can also include load decrease options, and the provision of negative reserves can also include load increase options. In this context, the demand response and management options can also participate in the reserve provision. The endogenous demand for reserve includes a deterministic component, which is the largest possible system imbalance due to the loss of a single grid element (N-1 criterion), and a probabilistic component. The latter is based on the joint probability density function of the distributions of the random variables contributing to the variation of the supply and the demand (e.g. forecast errors in the wind and solar production, forecast error in the electricity demand well as power plant outages). The total reserve requirement of each type is then the sum of the deterministic and the probabilistic component (for the latter we move ± 3 standard deviations σ in the joint probability distribution). The competitiveness of each power plant in participating in both electricity and balancing services markets is determined by its capital and operating costs, as well as its operating constraints. We model the provision and not the activation of the primary and secondary reserve since the latter requires a stochastic framework. Distributed energy sources (e.g. CHPs, solar PV, wind turbines, batteries, and heat pumps) can participate both in the ancillary and energy markets as virtual power plants, in which their operation is centrally controlled.

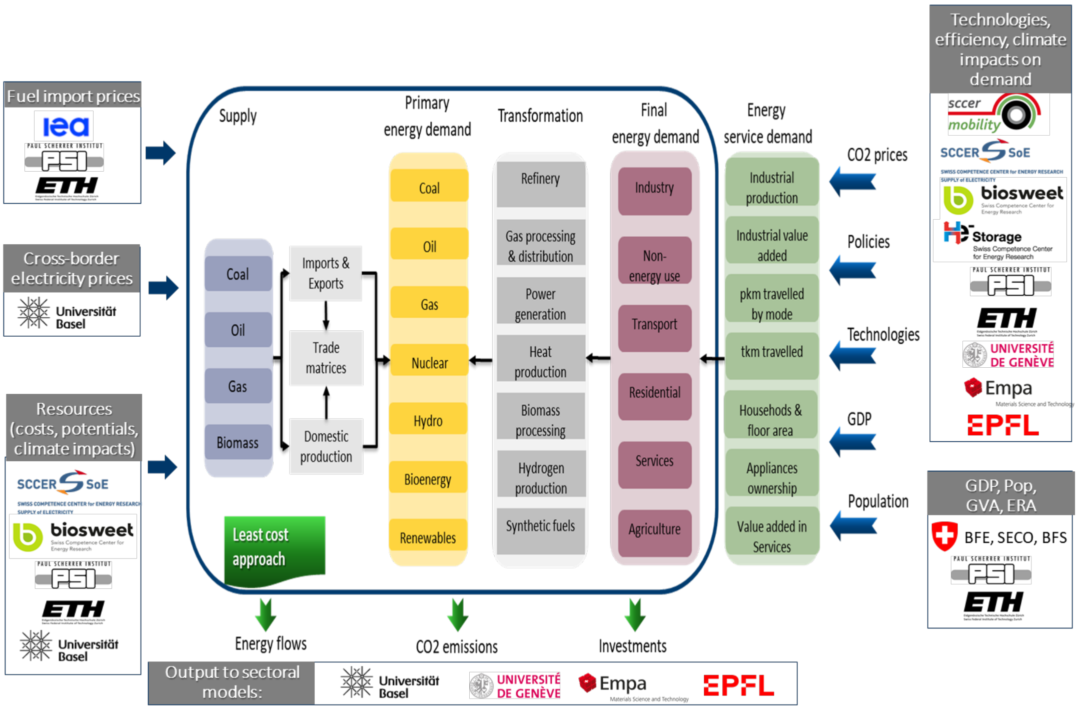


Figure 2.2: *Links of STEM within SCCER JASM and with other projects/SCCERs*

The model also includes demand-side management constraints, which enable the shifting of specific electricity loads. The different demand categories, e.g. heating, cooking, washing, etc., are associated with different flexibility levels modelled similar to storage processes. However, for demand-side flexibility we impose two constraints: a) that the amount that can be shifted in each operating hour is limited to a certain percentage of the total load; and b) the operating window of the "demand shift" (storage) process is not a full day but a balancing window for advancing or delaying the load. In addition, these processes can have costs, simulating discomfort costs when they invested by the model. Our methodology is a modification of the mechanism presented in (Pudjianto et al., 2014), and the parametrisation of the balancing windows, discomfort costs, and maximum load that can be shifted are based on Swiss consumer surveys and studies (e.g. (Hille et al., 2017, Soland et al., 2018, 2013, Hunziker et al., 2018)) as well as on international studies (e.g. (Gan et al., 2011, Papadaskalopoulos et al., 2013)). For thermal loads, the shift via heat pumps and water heaters is based on the methodology described in (Papadaskalopoulos et al., 2013). In STEM, the storage options are represented at different time scales and sizes. We include daily storage options (e.g. batteries), weekly storage options (e.g. pumped storage) and seasonal storage options (e.g. Power-to-X pathways). In addition, we distinguish between centralised and large-scale storage (e.g. pumped hydro and large stationary batteries) and distributed storage (e.g. batteries and heat storage). Because the increase in the hourly resolution without representing technical operating constraints is not sufficient to capture important aspects of power system flexibility (Collins et al., 2017), we include in the model a linearised approximation of the unit commitment problem. The formulation is based on (Panos and Lehtilä, 2016) and it helps in avoiding false insights regarding the system's capability to integrate renewable energy (Deane et al., 2012).

Finally, the model includes flexibility provided from the transport sector via grid-to-vehicle (G2V) and vehicle-to-grid (V2G) options. The modelling of these options is based on (Turton and Moura, 2008), by splitting the electric vehicle (battery and plug-in) into its battery component and the rest of the vehicle. The battery component is then linked not only to the vehicle but also to wiring systems for charging (G2V) and feeding (V2G) electricity. The model endogenously calculates the use of battery for driving and flexibility provision, based on degradation constraints similar to the ones described in (Brijs et al., 2017), costs of the G2V and V2G technologies obtained from (Turton and Moura, 2008), and willingness of consumers to provide this flexibility based on surveys, e.g. from (Kubli et al., 2018).

In the context of the SCCER Joint Activity Scenarios and Modelling, STEM was enhanced in the areas shown in table 2.1 and it was also enhanced from the collaboration with other SCCERs as well, as shown in figure 2.2.

Table 2.1: *Updates in STEM data based on collaboration with the sectoral models of SCCER JASM, as well as on collaboration of SCCER JASM with other SCCERs*

Sector	Data	Collaboration in the context of SCCER JASM
Upstream	Renewable Potentials	Updated based on collaboration between PSI, ETH and WSL from SCCER Biosweet
	Import prices	Update of cross-border prices for fuels and energy carriers based on joint work between PSI, ETH. For the electricity cross border prices the results from SWISSMOD from UniBas were used
	CO_2 domestic sequestration	Latest estimations from SCCER SoE and the ACT ELEGANCY project were used
	Cross-border trade capacities	Net Transfer Capacities for cross-border electricity exchanges were derived from SWISSMOD (UniBas)
	Hydropower climate change impacts	Water inflow profiles obtained from SWISSMOD (UniBas) simulations for three climate change scenarios RCP8.5, RCP4.5 and RCP2.6
Conversion	Electricity production technologies	Costs and performance updated from PSI reports, also in the context of SCCER SoE and SCCER JASM
	Hydrogen production technologies	Costs and performance updated from ETH and PSI collaboration in SCCER JASM and ACT ELEGANCY
	Biofuel production technologies	Costs and performance updated from SCCER JASM and SCCER Biosweet
	Synthetic fuels production	Costs and performance updated from SCCER HaE and ESI platform
End-use	Transport technologies	Costs and performance for vehicles updated from SCCER Mobility
	Building stock	Evolution updated based on PSI modelling and UniGE collaboration
	Demand profiles	Hourly demand profiles updated from UniGE
	Industry conservation measures	Costs and potentials updated from UniGE and EPFL
	Buildings conservation measures	Costs and potentials updated from UniGE and EMPA
	Electric appliances	Costs and potentials, as well as load profiles updated from UniGE
	Climate change impacts on heating and cooling demands	The HDD and CDD from three climate change scenarios simulations from HSLU were used to modify the levels of heating and cooling demands in STEM scenarios

More details regarding the common assumptions used in the context of SCCER JASM are given in the "JASM Framework and Drivers Report" (Marcucci et al., 2020)

2.2 Definitions of the core scenarios *BAU*, *EPOL* and *CLI*

Three core scenarios are examined with the Swiss TIMES Energy Systems Model (STEM). The scenarios reflect different transition pathways with respect to energy and climate policies.

The ***Baseline*** (short ***BAU***) scenario, assumes a continuation of existing trends in energy consumption and supply, as well as in the technology developments (costs and efficiency) for the energy production, distribution and use. It does not enforce specific long-term targets regarding renewables penetration, the deployment of energy efficiency improvement measures, or climate change mitigation. However, it implements the already decided phase-out of existing nuclear power plants (SFOE, 2017). The assumed lifetime of the existing nuclear reactors is 60 years, and the scenario takes into account the decommissioning of Mühleberg that was taken off the grid in December 2019. The *BAU* scenario is primarily used to compare and benchmark the developments and showcase upcoming challenges in long-term scenarios and variants related to the energy system transition.

The ***Energy Policy*** (short ***EPOL***) scenario takes into account the measures and targets of the Swiss Energy Strategy (SFOE, 2017), which is in force since 2018. It implements both the targets on renewable energy deployment and energy efficiency, as defined in the Swiss Energy Strategy. The energy efficiency includes both targets related to the reduction of overall energy consumption and electricity consumption. However, the *EPOL* scenario does not impose specific targets in emissions reduction. It can be considered as an explorative scenario regarding the decarbonisation of the Swiss energy system. Although *EPOL* does not include explicit overall decarbonisation targets, it includes the vehicle CO_2 emissions standards in-line with the Swiss Energy Strategy and the standards of the European Commission[1]. In addition, it assumes the interconnection between the Swiss and EU emissions trading schemes (ETS), and it implements the post-2020 2.2% linear emission reduction factors announced by the European Commission[2]. The *EPOL* scenario has been specifically built to evaluate the abatement level of greenhouse gases (GHG) emissions, which can be achieved with the implementation of efficiency measures towards a well-below 2000 Watt society by 2060.

The ***Net-Zero*** (short ***CLI***) scenario aims at achieving the target of net-zero emissions in 2050, in a context of phasing-out existing nuclear power plants. The Swiss Federal Council announced this ambition in summer of 2019, and it has been communicated as an indicative target in the UNFCCC (UNFCCC, 2020). The net-zero target in 2050, as the Swiss Federal Council announced, includes energy-related emissions, emissions from industrial processes and also non-energy related emissions from agriculture, wastes and LULUCF (SFOEN, 2020a). However, the analysis with STEM focuses only on achieving net-zero emissions in the energy system and industrial processes (i.e. it does not include emissions from agriculture and waste, other than fuel combustion)[3]. Besides this, the analysis does not consider compensation of domestic emissions abroad, although imported zero-carbon fuels and energy carriers can be regarded as such. The non-energy emissions could be at least 5 Mt CO_2-eq in 2050 of non-CO_2 greenhouse gases (SFOEN, 2020a). If in the current analysis the energy system were to offset these emissions too, the emissions target in *CLI* should have been set to at least -5 Mt CO_2 in 2050. The *CLI* scenario also implements sectoral policy measures and emissions targets described in the revision of the CO_2 law (SFOEN, 2020b), such as emissions standards for buildings and vehicles and promotion of renewable fuels in transport, as well as it also assumes the strengthening of

[1] See https://ec.europa.eu/clima/policies/transport/vehicles/regulation_en

[2] See https://www.europarl.europa.eu/RegData/etudes/BRIE/2017/614601/EPRS_BRI(2017)614601_EN.pdf

[3] STEM in an energy systems model. Including emissions from the non-energy sectors in the assessment requires interfaces with models for agriculture and forestry, which is not in the scope of the SCCER JASM project

Table 2.2: *Overview of the three scenarios regarding key energy and climate objectives*

Strategic Objective	BAU	EPOL	CLI
Nuclear power	All scenarios: No new nuclear power plants All scenarios: 60 years lifetime of existing power plants All scenarios: Mühleberg decommissioning December 2019		
Renewable energy	No specific targets	Non-hydro renewable energy: 2020: 4.4 TWh 2035: 11.4 TWh 2050: 24.2 TWh Hydropower: 37.4 TWh in 2035	No specific targets
Energy consumption efficiency	No specific targets	Final energy consumption per captia (excl. International aviation): -43% in 2035 from 2000 -54% in 2050 from 2050 Electricity consumption per capita: -13% in 2035 -18% in 2050	No specific targets
Emissions standards in buildings	No specific targets	No specific targets	Existing buildings: 12 $kgCO_2$/sqm in 2030 4 $kgCO_2$/sqm in 2040 0 $kgCO_2$/sqm in 2050 New buildings 0 $kgCO_2$/sqm from 2030
Emissions standards in vehicles	No specific targets	Private cars: 105 $grCO_2$/km in 2020 65 gr CO_2/km in 2030 25 gr CO_2/km in 2050 Light duty vehicles 160 $grCO_2$/km in 2020 110 $grCO_2$/km in 2030 60 $grCO_2$/km in 2050 Heavy duty trucks: 680 $grCO_2$/km in 2020 475 $grCO_2$/km in 2030 330 $grCO_2$/km in 2050 Coaches: 820 $grCO_2$/km in 2020 575 $grCO_2$/km in 2030 400 $grCO_2$/km in 2050 City buses: 1160 $grCO_2$/km in 2020 810 $grCO_2$/km in 2030 570 $grCO_2$/km in 2050	Private cars: 105 $grCO_2$/km in 2020 65 gr CO_2/km in 2030 16 gr CO_2/km in 2050 Light duty vehicles 160 $grCO_2$/km in 2020 110 $grCO_2$/km in 2030 60 $grCO_2$/km in 2050 Heavy duty trucks: 680 $grCO_2$/km in 2020 475 $grCO_2$/km in 2030 330 $grCO_2$/km in 2050 Coaches: 820 $grCO_2$/km in 2020 575 $grCO_2$/km in 2030 400 $grCO_2$/km in 2050 City buses: 1160 $grCO_2$/km in 2020 810 $grCO_2$/km in 2030 570 $grCO_2$/km in 2050
Emissions trading scheme linear reduction factors	No specific targets	Coupling of Swiss and EU ETS ETS linear factor increases by: 2.2% until 2030 2.6% until 2040 2.6% until 2050	Coupling of Swiss and EU ETS ETS linear factor increases by: 2.2% until 2030 2.6% until 2040 2.8% until 2050
CO_2 emissions reduction target	No specific targets	No specific targets	Net zero in 2050 from fuel combustion and industrial processes excl. International aviation and agriculture

the Swiss and EU emission trading schemes. Beyond 2030, the vehicle emissions standards and ETS targets are based on scenario projections from the European Commission (E3mlab and IIASA, 2017, EC, 2018), while for buildings the MINERGIE standards are extrapolated (Sidler and Humm, 2019).

A brief overview of the three scenarios with respect to key strategic objectives is shown in Table 2.2. The main sources for the energy and climate targets until 2030 is the Swiss energy strategy 2050 (BFE 2017) and the revision of the CO_2 law (FOEN 2020). The targets beyond 2030 are based on extrapolation using the NEP scenario of (prognos 2012) and European scenarios of the EU Commission regarding decarbonisation (EC 2018). The three core scenarios do not only differ from each other with respect to the implemented energy and climate policies, but they are also different regarding the climate change impacts on space heating/ air conditioning demands and hydropower. Based on the overarching assumptions in (Marcucci et al., 2020), the climate impacts in *BAU*, *EPOL* and *CLI* scenarios are based on the RCP8.5, RCP4.5 and RCP2.6 climate scenarios (CH2018, 2018), respectively.

2.3 Definitions of the variants of the core scenarios

The variants of the core scenario are built around four main storylines, as shown in figure 2.3. They specifically address the availability of resources, the technological progress, the integration of the energy markets and the role that social acceptance can play in achieving the ambition of net-zero emissions by 2050. The variants are briefly described below, starting from the one which is more restricted regarding the available solutions towards decarbonisation and ending to the one with the most favourable national and international policy, technology and societal contexts for achieving energy and climate policy targets. The implementation details of the variants are given in section 8:

- ***Fragmented global policy*** (short ***ANTI***). This variant assumes an international context with low cooperation in mitigating climate change. Due to the fragmented climate policies worldwide, there is stagnation of R&D expenditures in low-carbon technologies. There is limited technological progress, and, as a result, both consumers and utilities are faced with high upfront capital costs when adopting low-carbon solutions for energy supply and use. The integration of the Swiss and international energy markets is weaker in *ANTI* than in the core scenarios, which hinders the availability of imported zero-carbon fuels and energy carriers, including electricity. In this setup of the national and international context, there is also limited tolerance from the society regarding landscape changes for the implementation of renewable and other low-carbon projects. The focus in *ANTI* is more on adaptation than mitigation. Capital-intensive projects for reducing the carbon footprint of the Swiss energy system are postponed to the future.

- ***Energy security*** (short ***SECUR***). This variant builds upon *ANTI*, by assuming the same fragmented climate change policies worldwide but a Swiss society that is keener in using domestic renewable resources to reduce the carbon intensity of the Swiss economy. In this regard, there is a higher social acceptance in implementing projects based on new renewable energy forms such as bioenergy, geothermal and solar. Priority for consumers and utilities in this variant is the secure and reliable operation of the Swiss energy system, given the weak integration of Swiss and international energy markets. The reduction of the overall import dependency in future is a priority. To secure the reliable operation of the domestic grid, its reinforcement is highly acceptabe in *SECUR*, and also desirable in order to mitigate congestion.

- ***Market integration*** (short ***MARKETS***). In this storyline, there is higher global cooperation and integration of the Swiss and international energy markets beyond the levels assumed in the core scenarios. Therefore, the *MARKETS* variant allows increased availability of imported biofuels, synthetic e-fuels, hydrogen and electricity. Priority in *MARKETS* is the decarbonisation through affordable energy, which is also achieved via the development of local energy markets and intelligent “prosumage” schemes in coordination with national energy markets. As a result, technologies enabling sector coupling, prosumers and storages, as well as demand-side management and vehicle-to-grid enjoy economies of scale and their costs are lower than in the core scenarios. In order to support the integration of domestic and national markets, grid congestion is eliminated to a large extent by reinforcing domestic grids. With the focus on new business models based on renewable energy and P2X pathways, the social acceptance for using domestic renewable energy resources is higher than in the core scenarios and similar to the levels in *SECUR*.

- ***Technology innovation*** (short ***INNOV***). This variant builds upon *MARKETS* by assuming the same developments regarding the integration of local, national and international energy markets, and by additionally assuming that there is a global effort to mitigate climate change and achieve the Paris Agreements. Closer international coordination is not only assumed with respect to the implementation of climate change policies worldwide but also on reducing the costs of low-carbon technologies in energy supply and demand via increased R&D expenditures worldwide. Circular economy policies and schemes emerge globally, and there is a high level of material efficiency that also results in lower energy conservation and renovation costs compared to the core scenarios. Moreover, in a context of a global joint effort to reduce GHG emissions, there is also high social acceptance and support from consumers in adopting new technologies that can contribute in achieving the ambition of net-zero emissions in 2050. Thus, the costs of clean and low carbon technologies, such as renewable technologies, alternative vehicles and CCS, as well as the costs of efficiency measures in energy supply and demand are lower in this variant than in the core scenarios. As *INNOV* builds on *MARKETS*, grid reinforcement and high availability of imported zero-carbon fuels and energy carriers are also assumed in this variant.

The definition of the main storylines is based on the higher and lower estimates for potentials, cross-border capacities, import prices of energy carriers, as well as technology costs, which are reported in (Marcucci et al., 2020, Bauer et al., 2019, 2017).

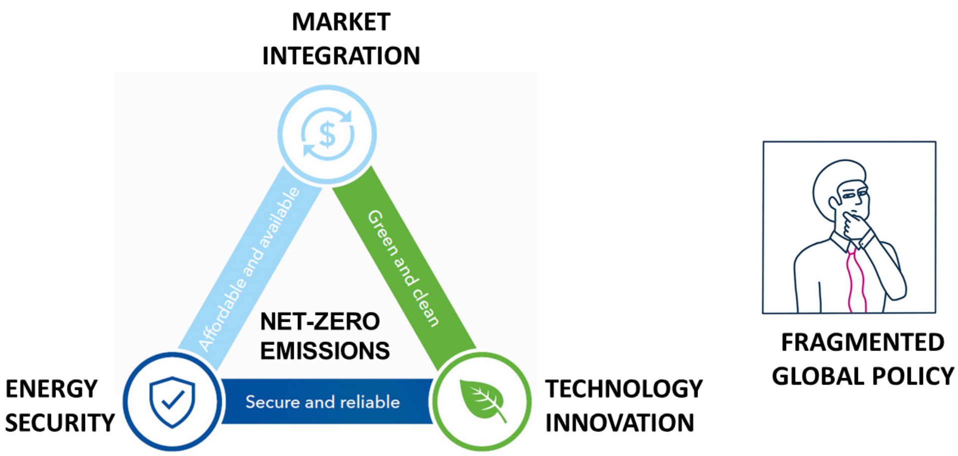


Figure 2.3: *The four storylines used in the assessed variants with respect to the Energy Trilemma*

Besides these four main storylines, there are variants of *EPOL* and *CLI* scenarios that lift specific energy and climate policies, as summarised below:

- ***EPOL-E***: in this variant of *EPOL* the per capita electricity reduction target is not included.

- ***CLI80***, ***CLI100***: these two variants of *CLI* are inspired by the collaboration with the SCCER Efficient Technologies and Systems for Mobility. In both *CLI80* and *CLI100*, the emissions standards in vehicles, the emissions standards in buildings, and the ETS linear emissions reduction factor do not become more stringent beyond 2030, but they remain at the levels of 2030 throughout the period of 2030-2050. In *CLI80*, the emissions reduction target is set to 80% compared to 1990 levels, while in *CLI100*, the emissions trajectory is the same as in the *CLI* scenario. Since the *CLI100* variant does not implement the whole spectrum of policies described in the revised CO_2 law (SFOEN, 2020b), it can be regarded as quite close to the *Least Cost* solution, in which the model is free to take decisions, constrained only by the overarching emissions reduction targets in 2030 and 2050.

2.4 Key scenario assumptions related to energy service demands

This section summarises key scenario assumptions in the core scenarios, which are built on the macro-economic and demographic drivers of the SCCER JASM project (Marcucci et al., 2020). The population and economic growth are the same across all core scenarios and the variants. The energy demands in the core scenarios differ due to the assumed different climate change impacts. The energy demands of the variants are the same as the demands of the core scenario to which they refer.

2.4.1 Households sector

2.4.1.1 Space heating and warm water heating demand in the residential sector

The specific energy service demand for space heating, which is assumed in (Marcucci et al., 2020), is additionally influenced in the analysis with STEM by the climate change impacts assumed in each scenario and which are expressed as the number of heating degree days. Figure 2.4 presents the assumed demand for space heating for different types of houses after correcting for the climate impacts in the three core scenarios.

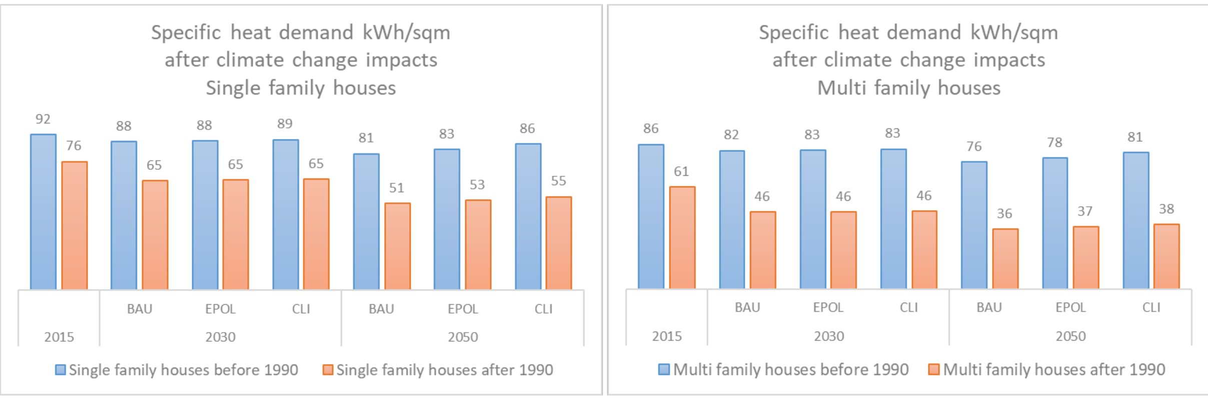


Figure 2.4: *Specific demand for space heating after incorporating the climate change impacts of RCP8.5, RCP4.5 and RCP2.6 in the BAU, EPOL and CLI scenarios, respectively*

The *BAU* scenario has the lowest demand for space heating per square meter. This is because *BAU* follows the RCP8.5 trajectory in temperature increase (Masson-Delmotte et al., 2018, CH2018, 2018), which results in significant global warming due to the absence of strong global policies to mitigate climate change. Therefore there is less need for heating (on average, as the analysis does not consider extreme weather events which can accentuate in a context of strong global warming). In contrast, the *CLI* scenario has the highest demand for space heating as it follows the RCP2.6 trajectory in temperature increase, with a significantly lower intensity of global warming compared to RCP8.5 and RCP4.5.

Finally, the *EPOL* scenario assumes a temperature increase compatible with the RCP4.5 trajectory, and it stands between *BAU* and *CLI* in demand for space heating.

Besides the climate change impacts, and the level of the temperature increase, the demand for space heating is highly influenced by residential building stock development. The increase in the population by almost 2 million between 2015 and 2050 accentuates housing needs. Based on the analysis with the building stock model of PSI (Panos, 2020a), the number of residential buildings increases by almost 235,000 between 2015 and 2050.

Consequently, there is an increase in the total Energy Reference Area (ERA) in the residential sector of about 157 million square meters in 2050 from 2015. The largest increase is shown in demand for multi-family houses. However, despite the increase in the overall ERA, the demolition of the existing building stock and the better insulation of the new constructions enforced by more stringent building standards (Sidler and Humm, 2019), result in a reduction in the overall demand for space heating in 2050, compared to 2015 (right-hand side in figure 2.5). It should be noted that the demolition rates of existing buildings are the same in all scenarios and variants.

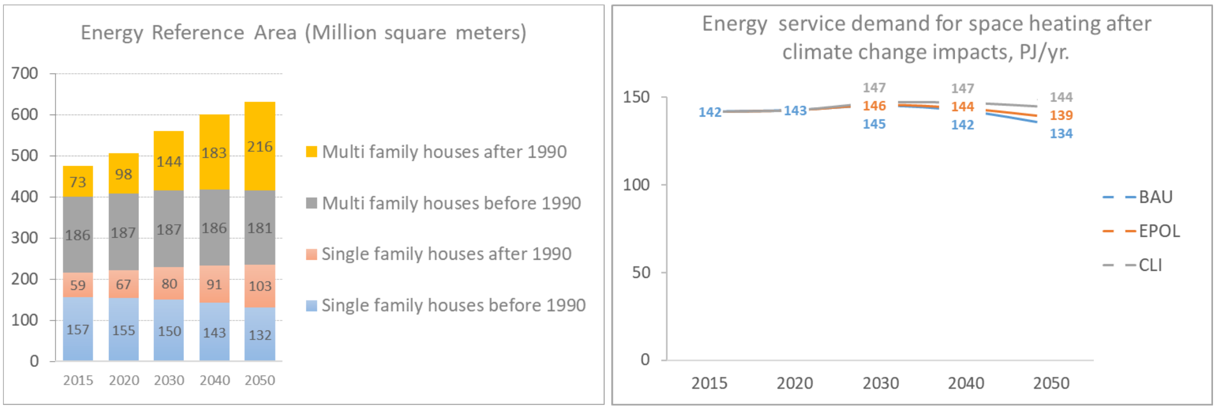


Figure 2.5: *Energy reference area (left) and total energy service demand for space heating (right)*

Regarding the demand for hot water, today on average is around 800 kWh/capita, and it is assumed that this level largely remains in the future. The population's increase pushes the total demand upward in 2050 (figure 2.6).

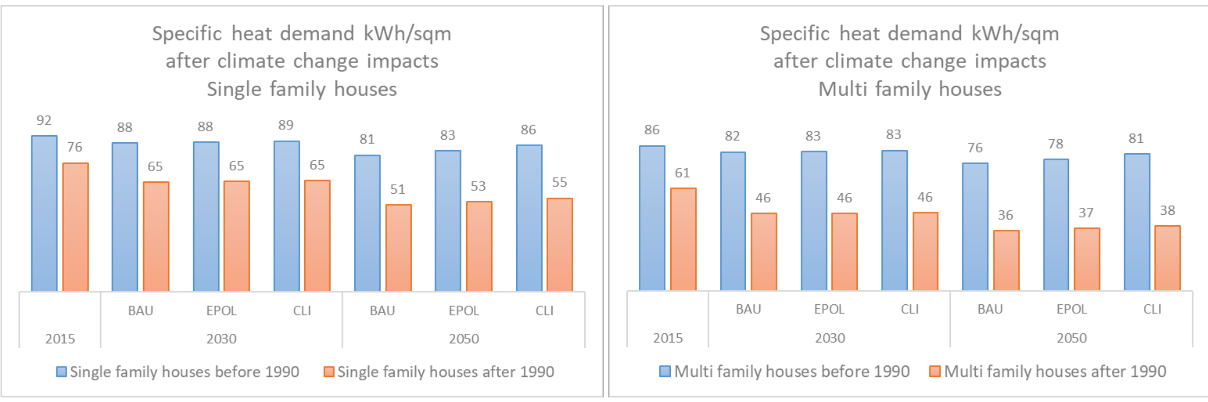


Figure 2.6: *Energy service demand per capita for hot water in the residential sector after applying the impact of the different heating degree days assumed in the three core scenarios*

2.4.1.2 Air conditioning demand

The demand for air conditioning in the residential sector depends on the developments in the overall energy reference area and the number of cooling degree days according to the three climate scenarios RCP8.5, RCP4.5 and RCP2.6 which are assumed for *BAU*, *EPOL* and *CLI* respectively.

The energy reference area for air conditioning increases from about 11 million square meters in 2015 to 282 million square meters in 2050, as a direct result of the increase in the building stock and the assumed cooling degree days (Marcucci et al., 2020). About 85 million square meters of this increase (or one-third of the added cooling area) is attributable to buildings built after 2015, which are assumed to follow the new MINERGIE standards. As a result of the more energy-efficient new buildings, the average specific air-conditioning demand across all buildings declines from 16.3 kWh/sqm in 2015 to 12.6 kWh/sqm in 2050. By applying the correction for the climate change impacts, the *CLI* scenario with the lowest number of cooling degree days also has the lowest energy service demand for cooling. In contrast, the *BAU* scenario with the highest number of cooling degree days has the highest energy service demand (see figure 2.7).

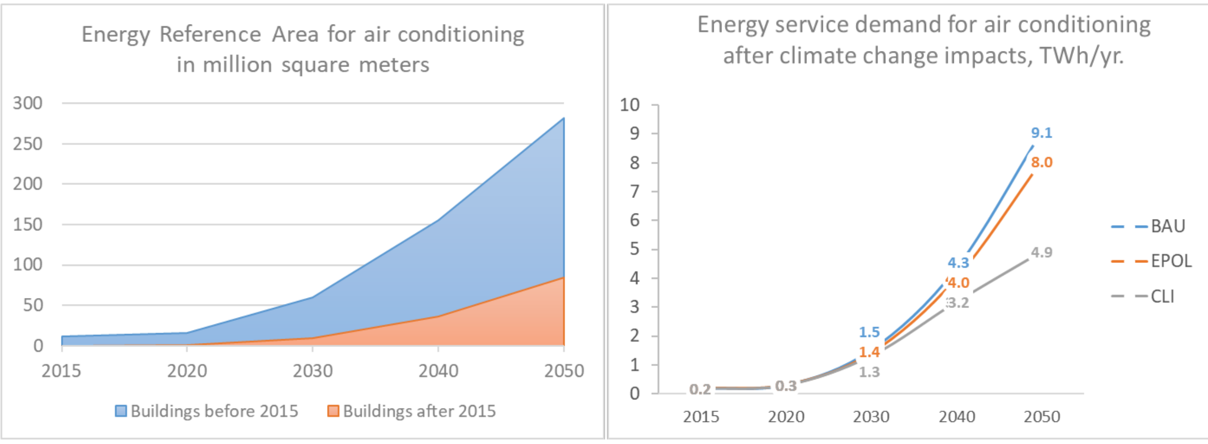


Figure 2.7: *Energy service demand for cooling, by building age (left) and by scenario (right) after adjusting for the climate change impacts*

2.4.1.3 Electric appliances

The ownership of electric appliances is the same in all three core scenarios, based on the common assumptions regarding the number of households and their incomes. Using an ownership model (Panos, 2020b), the number of the different types of appliances is forecasted from 2015 to 2050. The efficiency of the appliances is based on relevant work from the University of Geneva (Yilmaz, Majcen, Heidari, Mahmoodi, Brosch and Patel, 2019). Figure 2.8 presents the evolution of the different electrical appliances in the household sectors.

Computers, tablets, pads, smartphones and other “wearables” have the largest increase in the next decades. White appliances show saturation effects regarding their total number from 2015 to 2050, as their penetration is mainly based on the increase of households. However, the sales of white appliances do not stagnate as there will be a replacement of existing equipment with a more efficient one. Finally, there are a few electrical devices that are in a constant decline in the forthcoming years, reflecting the new trends in the online streaming of music and videos. These include the video and

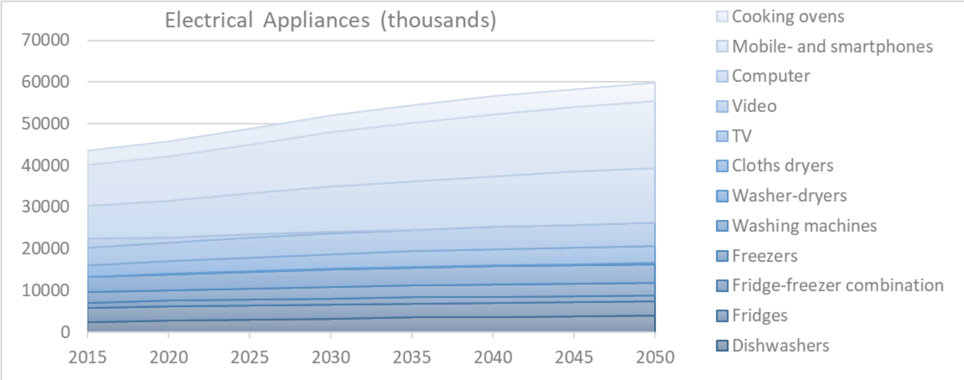


Figure 2.8: *Evolution of electric appliances in the household sector in the three core scenarios*

DVD players and conventional TV systems, which are substituted by monitors/projectors and streaming platforms.

2.4.2 Industry and services

Their economic and physical output drives the energy service demand in industry and services sectors, expressed as gross value added and production index, respectively. Figure 2.9 shows the projection of the gross value added in industry and services assumed in the analysis, which follows (Marcucci et al., 2020). The services sectors account for about three-quarters in total gross value added. There is also a progressive structural change of the Swiss economy towards less energy-intensive industries and services, as their share in the Swiss gross domestic product (GDP) continues to increase over time. In this context, sectors with higher value-added develop more rapidly than sectors that are heavily dependent on energy and materials consumption. This trend lowers the Swiss economy's overall energy intensity and accelerates the decoupling between energy consumption and economic activity in the coming years. As a result, while the gross value added in industry increases by 1.1% p.a. between 2015 and 2050, the production index increases by 0.7% p.a. over the same period. Finally, more than two-thirds of the Swiss GDP is produced by the services and commercial sectors alone, particularly the insurance, financing and trade sectors. Among the industrial sectors, the chemicals and pharmaceuticals have a substantial contribution to GDP.

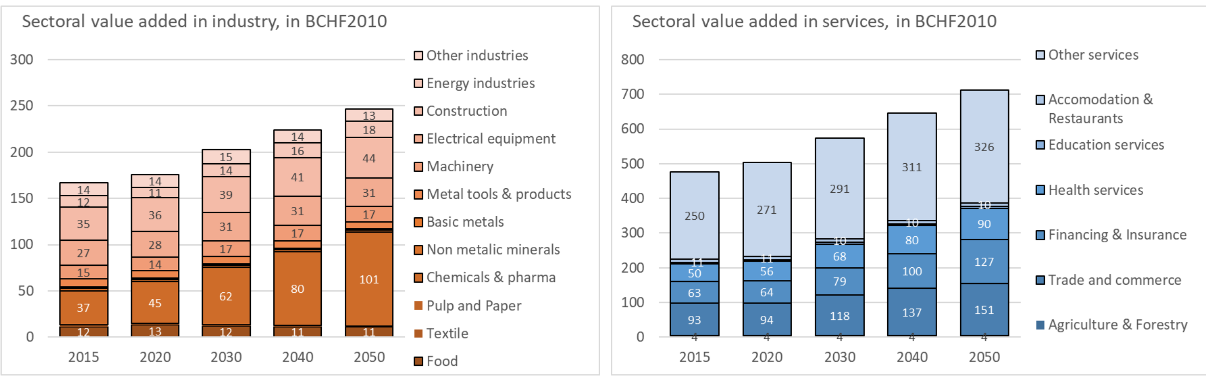


Figure 2.9: *Sectoral value added in industrial, services, commercial and agriculture sectors*

The energy reference area in industrial and services sectors combined grows by almost one-quarter from 2015 to 2050, due to the increased economic and production activities. As shown in figure 2.10, the energy reference area in offices for industry remains almost constant between 2015 and 2050.

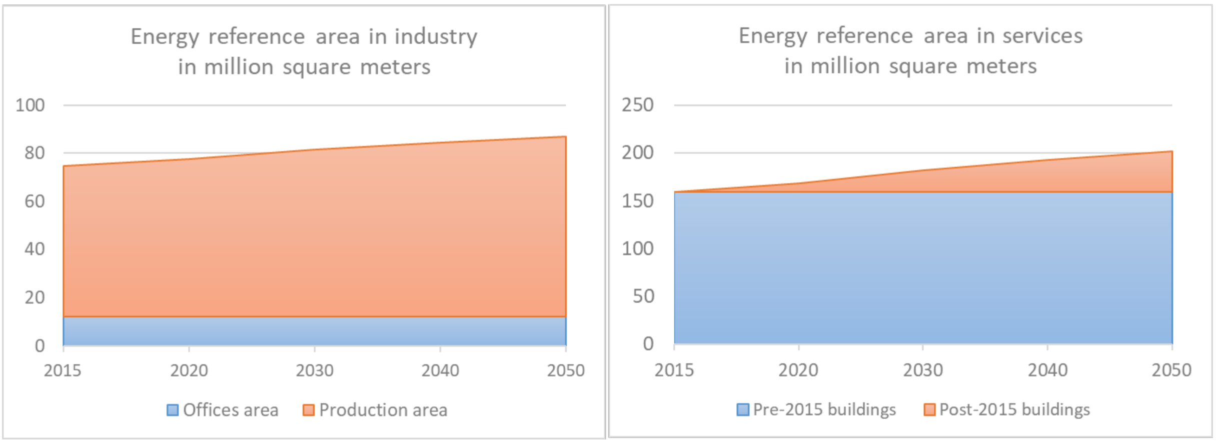


Figure 2.10: *Energy reference area in industrial sectors (left) and services, commercial and agriculture sectors (right). The figure excludes area that is not heated or not used*

The main driver of the increasing ERA in industry is the need for additional production space. Regarding the services sectors, the energy reference area of the existing building stock remains almost constant between 2015 and 2050. The share of new buildings contributes to about 20% of the total energy reference area in the services, commercial and agriculture sectors in 2050.

2.4.3 Transport

Passenger and freight transport demands are drawn from the trends described in the reference scenario of ARE (Mathys and Justen, 2016). Regarding the demand for passenger mobility (figure 2.11), there are saturation effects with respect to the growing incomes.

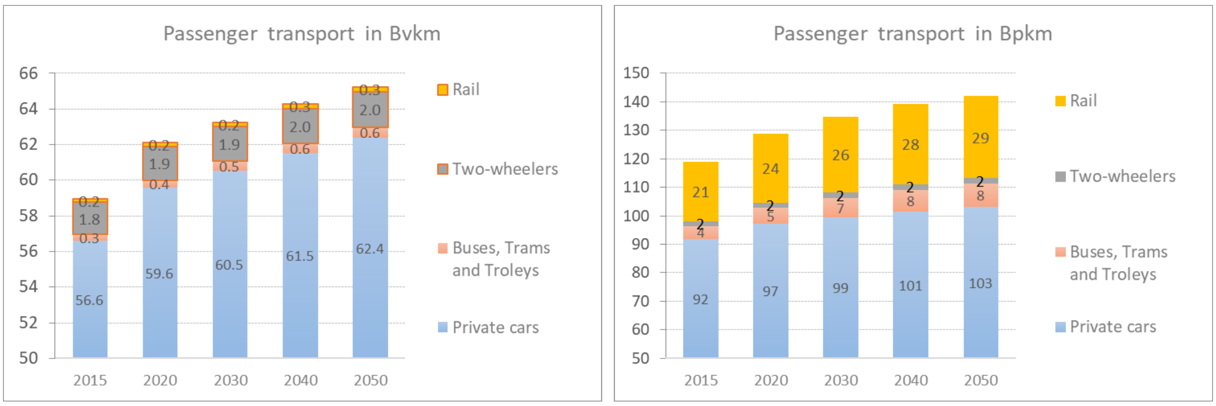


Figure 2.11: *Private and public transport demand in billion vehicle kilometres (left) and billion passenger kilometres (right). Note that the vertical axis does not start at zero*

In the private cars sector, car ownership rate increases from 540 cars per thousand persons in 2015 to 553 in 2030 and remains stable until 2050. These saturation effects in car ownership imply a deceleration in vehicle stock growth until a stagnation is reached after 2030. The combination of decelerating stock growth and current vehicle scrapping rates would normally result in virtually stable new registrations around at the present levels. However, it is assumed that as per capita incomes increase, the average life of vehicles declines, and, as a result, scrapping accelerates leading to market expansion. Hence, the growth in private cars is about 28% from 2015 to 2050 or 1.3 million cars. This growth dynamic is an important factor for vehicle stock renovation and the potential for introducing new technologies, especially in the later years. Finally, public transport sees a stronger increase in terms of passenger kilometres than individual motorised transport. Most of the increase in public transport is attributable to railways.

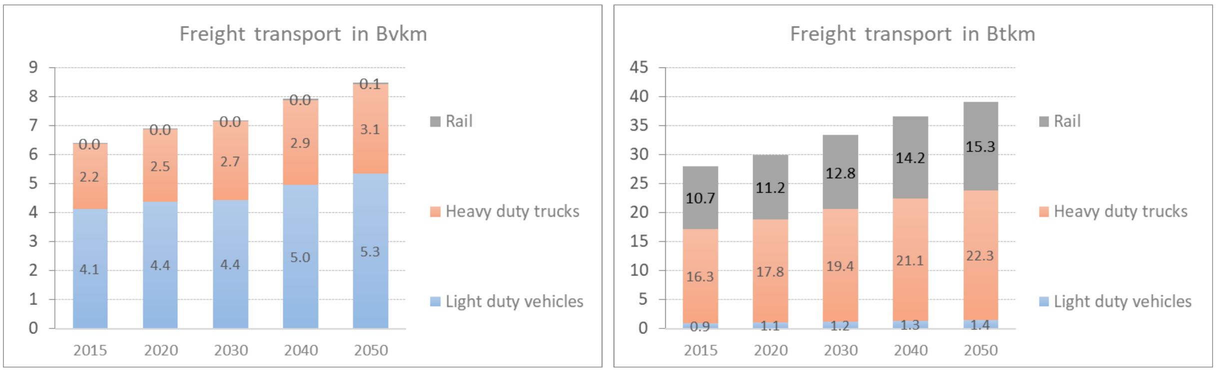


Figure 2.12: *Freight transport demand in billion vehicle kilometres (left) and billion-ton kilometres (right)*

Main drivers for the increase in freight transport demand (figure 2.12) are the population and economic growth. However, the growth of freight transport remains below the GDP growth over the period of 2015 – 2050. This indicates a decoupling from the economic activity, i.e. between the volume carried and the kilometres travelled, supported by load and logistics optimisation. It is also assumed a stronger increase for rail freight than for road freight transport, which is also driven by the shift in economic structure to less energy-intensive activities.

We assume current climate levy and fuel tax also apply to transport fuels and energy carriers in future.

2.5 Assumptions on cross-border prices, resources and technologies

Besides the aforesaid domestic demand drivers, the international context is also a key influential factor for the future development of the Swiss energy system, which is affected by the prices of imported energy carriers. Building on (Marcucci et al., 2020), two distinct fuel price trajectories are assumed (table 2.3) - the first trajectory corresponds to a worldwide continuation of existing trends and policies (*Reference* in table 2.3), and it is used in the *BAU* and *EPOL* scenarios. The second trajectory corresponds to a normative scenario with a global effort to limit the increase in the average surface temperature below 2^{o}C by the end of the century compared to pre-industrial levels (*Climate* trajectory in Table 2.3). This trajectory is used for the net-zero emissions core scenario and variants.

Table 2.3: *Import prices at the Swiss border, excluding taxes and transmission tariffs*

		Reference (CHF2010/GJ)			Climate (CHF2010/GJ)		
	2020	2030	2040	2050	2030	2040	2050
Crude oil	8.8	18.5	20.7	22.8	11.0	10.7	10.3
Natural gas	3.1	9.3	10.4	11.0	7.4	6.9	6.5
Biodiesel / PtL diesel*	42.7	49.7	52.4	55.0	56.4	65.7	70.8
Ethanol / PtL gasoline*	30.4	39.4	41.9	44.3	48.2	59.2	64.1
Biogas	17.0	19.1	22.3	24.4	20.6	24.2	27.4
Electricity**	16.7	21.2	20.3	18.0	27.7	27.7	28.9
Hydrogen	26.9	40.1	42.7	44.7	41.6	44.4	52.1

** Price refers either to diesel/gasoline from biogenic sources or imported e-fuels*
*** Electricity prices are averaged across the neighbouring countries and across the hours of a year*
Source: SCCER Joint Activity Scenarios and Modelling

Regarding cross border electricity interconnector capacities, the Net Transfer Capacities (NTCs) are based on (Marcucci et al., 2020). The "*current*" trajectory in table 2.4 is used for the *BAU* and *EPOL* scenarios, while the "*decarb*" trajectory is used for the *CLI* scenario. The potentials of the renewable resources are based on (Bauer et al., 2017, 2019, Guidati et al., 2020, Marcucci et al., 2020). The assumptions on NTCs and the renewable potentials are shown in table 2.4. Finally, the potential for heat from waste water as a source for centralised heat pumps is based on (Gutzwiller et al., 2008).

Table 2.4: *Average annual net transfer capacities in GW (left) and exploitable remaining sustainable resource potentials (right)*

Net transfer capacities in GW, annual averages

Variant	both	both	current	decarb
Year	2020	2030	2040	2040
From-to				
Switzerland–Germany	4.6	5.6	6.5	6.5
Switzerland–France	1.3	1.3	2.8	3.8
Switzerland–Italy	4.2	6	6	6.0
Switzerland–Austria	1.2	1.7	1.7	1.7
Germany–Switzerland	2.7	3.3	4.1	4.1
France–Switzerland	3.2	3.7	5.2	6.2
Italy–Switzerland	1.9	3.0	3.7	3.7
Austria–Switzerland	1.2	1.7	1.7	1.7

Resource potentials in TWh/yr.

	2030	2050
Hydropower	37.4	37.6
Wind	4.3	4.3
Deep geothermal	4.4	4.4
Solar PV*	50.0	50.0
Solar thermal*	12.5	12.7
Heat from waste water**	5.8	5.8
Forest wood	6.8	9.6
Wood from landscape	0.9	1.2
Wood residues	2.1	2.1
Waste wood	3.5	4.3
Manure	2.9	7.5
Green waste	1.8	3.0
Sewage sludge	1.5	1.7
Mixed fossil waste	16.6	17.2
of which industrial (non renewable)	3.0	3.0
of which municipal (renewable)	6.8	7.1
of which municipal (non renewable)	6.8	7.1

* The potential considers roof top panels and there is also the additional constraint of the available roof top area
** Produced by centralised heat pumps using waste water as a heat source

Finally, table 2.5 presents the distribution of the electricity import prices according to the country of origin. In 2050, the median electricity price across all countries is around 100 CHF/MWh (see also table 2.3). Still, there are also good chances for higher electricity prices as well, as the distributions are skewed to the right.

The assumptions of costs and efficiencies for key energy supply and demand technologies are described in detailed in (Marcucci et al., 2020).The main sources used are (Bauer et al., 2019, 2017) for electricity generation technologies, (IEA, 2019) for hydrogen production technologies, (Panos and

Table 2.5: *Range of electricity import prices according to the country of origin, in CHF$_{2010}$/MWh*

Percentiles according to country of origin		Reference 2030	Reference 2040	Reference 2050	Climate 2030	Climate 2040	Climate 2050
Austria	1%	28	27	28	48	43	43
	25%	48	55	50	86	90	78
	50%	55	64	60	98	106	96
	75%	60	68	70	104	113	109
	99%	75	129	252	114	194	163
France	1%	9	2	2	9	2	3
	25%	32	25	23	46	36	42
	50%	44	43	38	65	65	66
	75%	54	50	48	79	78	86
	99%	72	90	103	99	130	137
Germany	1%	26	21	20	45	34	30
	25%	44	49	42	78	80	91
	50%	50	57	50	89	95	104
	75%	56	62	58	95	103	125
	99%	71	117	145	107	175	230
Italy	1%	14	1	1	23	2	2
	25%	88	54	28	122	86	106
	50%	113	87	76	147	134	151
	75%	118	94	96	153	146	172
	99%	124	374	352	159	516	547

Kannan, 2016) for end-use boilers and heat pumps, and the SCCER Efficient Technologies and Systems for Mobility (SCCER Mobility) for the transport technologies (Sacchi et al., 2021). The characterisation of the biomass-related technologies in the energy conversion sectors, as well as the identification of the various biomass conversion routes considered in the context of the SCCER JASM, is based on the collaboration with the SCCER Biomass for Swiss Energy Future (SCCER Biosweet) as it is described in (Guidati et al., 2020).

Chapter 3

Results and analysis of the energy demand sectors

The discussion in this section focuses largely on the results of the *CLI* (*net-zero emission*) scenario. It compares the corresponding results to the other two core scenarios while providing additional insights regarding the developments in the different energy demand sectors.

As shown in figure 3.1, the final energy consumption in 2050 is lower than today in all three core scenarios. In the *BAU* scenario, the reduction in the final energy consumption is attributable to the continuation of the current trends. In *EPOL* the deployment of efficiency measures, and in *CLI* the additional change in the energy mix driven by fewer fossil fuels and increased use of electricity (and clean fuels), reduce the overall levels of the final energy demand well beyond *BAU* in the period to 2050.

Moreover, in *CLI*, the total final energy consumption is lower than in *EPOL* throughout the period from 2020 to 2050, albeit the difference is relatively small. This outcome indicates that achieving net-zero emissions in 2050 would need to meet the efficiency targets in the Swiss Energy Strategy 2050. The energy consumption per capita in 2050 compared to 2000 is 44% lower in *BAU*, 54% lower in *EPOL* (given as a target), and 55% lower in *CLI*.

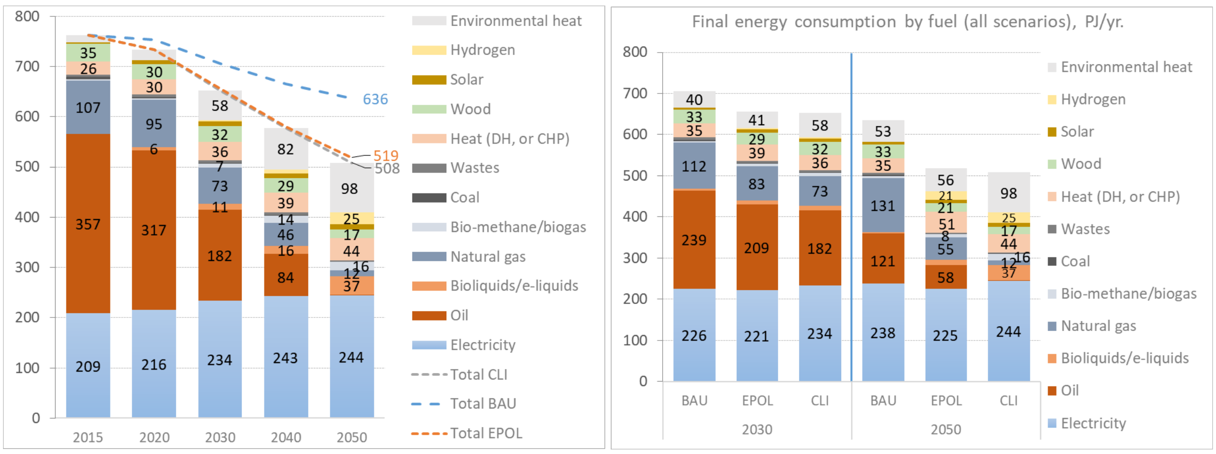


Figure 3.1: *Total final energy consumption by fuel in CLI (left) and all scenarios (right) excluding fuel consumption in international aviation and on-site CHP plants*

Figure 3.2 presents the overall final energy consumption by sector in the three scenarios. The transport sector displays the largest reduction of energy demand in both the *CLI* and *EPOL* scenarios, with the energy consumption in the sector being the half in 2050 compared to 2015. This development is triggered by the vehicle emission standards in these two scenarios that accelerate the deployment of alternative, and more efficient, drivetrains. Additionally, in *CLI* the net-zero target induces further penetration of clean and efficient drivetrains in mobility compared to *EPOL*.

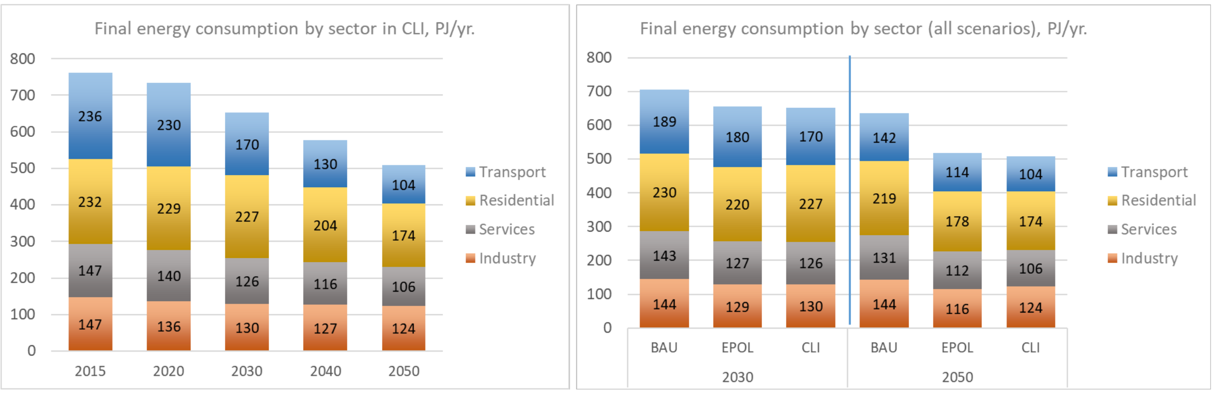


Figure 3.2: *Total final energy consumption by end-use sector, excluding the fuel consumption in international aviation and on-site CHP plants, in the CLI scenario (left) and across all scenarios (right)*

Next to the transport sector, the residential and commercial sectors also achieve high energy savings in both *CLI* and *EPOL* scenarios. However, the final energy consumption in industry plateaus in *CLI* in the post-2030 period because of the increased energy consumption needed to operate CO_2 capture, mainly in the cement sector. By excluding the consumption in carbon capture installations in industry, then *CLI* achieves similar energy-saving reductions as *EPOL* in the total energy needs of the sector.

Overall, the electrification of the demand in the *CLI* scenario reaches 48% in 2050, signalling the role of electricity in decarbonising the end-use sectors. This also implies that the availability of affordable electricity at sufficient scale will be an important factor for industry and other sectors of the economy. Switching the fuel mix in the end-use sectors from fossil fuels to electricity and other zero-carbon carriers such as green hydrogen, e-fuels and biofuels would require a major development of the energy system and the accompanying infrastructure.

Hence, the transition of the Swiss energy system towards net-zero emissions by 2050 would require, in some cases, breakthroughs in technologies to be developed or their technology readiness to be increased to ensure market uptake. Strong support through research and innovation will be needed to prove new solutions based on emerging technologies, and to scale-up technologies to large demonstration projects. The transition speed is such that many new technologies should be ready for large-scale deployment by the 2030s. This implies that well before then, it has to be a business case for investment.

3.1 Households

3.1.1 Transformation pathways

Households are at the heart of the energy transition. Efficient appliances, building renovation and heat pumps play a major role in the future energy system in all three core scenarios, and in particular in *CLI*. Figure 3.3 shows the efficiency gains in the residential space and water heating demand due to technology switching (on the left-hand side of the figure) and due to the deployment of renovation and insulation measures in buildings (on the right-hand side of the figure) in the three core scenarios.

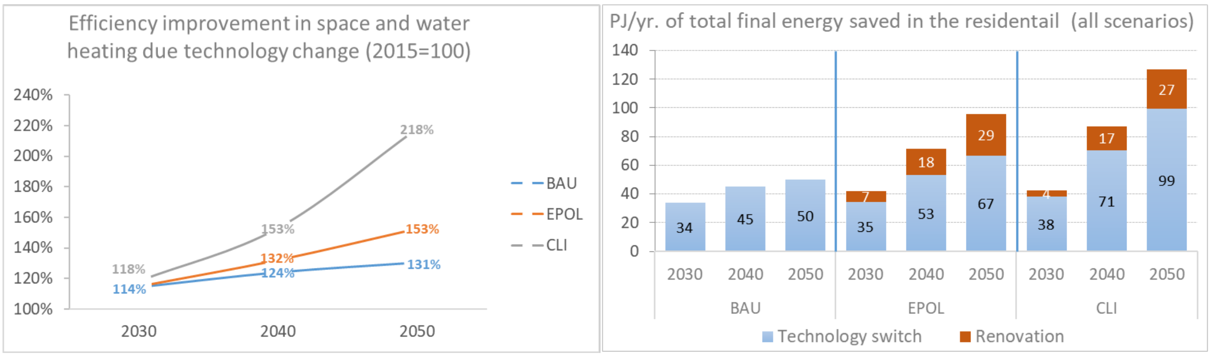


Figure 3.3: *Efficiency gains due to technology switching in space and water heating (left) and savings in final energy consumption (right). The gains are calculated by assuming that the technology mix and renovation levels of 2015 are used to satisfy future demands*

In *BAU*, the efficiency gains are achieved via technology switch and plateau after 2030. In *EPOL*, there is a significant additional deployment of renovation and insulation measures in buildings to be able to meet the stringent efficiency targets. The most pronounced energy savings of the sector is seen in the *CLI* scenario. Not only there is an accelerated replacement of ageing, carbon-intensive and inefficient heating equipment, but also there is a significant increase in the speed of renovation and insulation after 2030. Still, in *EPOL*, there is a faster implementation of renovation measures until 2040 compared to *CLI*. The accelerated renovation in *EPOL* is due to the imposed target of reducing the electricity consumption per capita in 2035, and beyond, that hinders the deployment of heat pumps and increased electrification, which otherwise could have resulted in efficiency gains via technology switching (as it is the case in *CLI*). However, the overall energy savings in *CLI*, both from technology switching and renovation, are constantly surpassing *EPOL* throughout the projection period.

To realise the incremental energy savings in *CLI*, clear, and consistent long-term pricing signals are needed to move markets quickly towards low carbon technologies and best building practices. As upfront capital costs are high and the energy-saving measures need to be rapidly deployed in the first decade from now by when the insulation measures are still not cost-efficient, unprecedented policy action is needed to avoid locking in inefficient and carbon-intensive building assets.

Figure 3.4 shows the penetration of technologies in space and water heating over time. In *CLI*, the growth in heat pumps is substantial in the first two decades at the expense of oil-based heating. The deployment of heat pumps in *EPOL* scenario lags about a decade compared to *CLI*, and this is because of the absence of a strong climate policy that could have accelerated further deployment. The technology diffusion shown in figure 3.4 suggests that achieving the net-zero emissions ambition requires an alignment between the timeframe of action and the near-term energy and climate change mitigation targets, in order to avoid lock-in of emission-intensive infrastructure and stranded assets in the residential heating after 2030. The case of *EPOL* clearly shows that only focusing on efficiency gains in the near term does not prevent the expansion of gas-based heating, if the policy does not deliver clear long-term pricing signals to switch to a less carbon-intensive option.

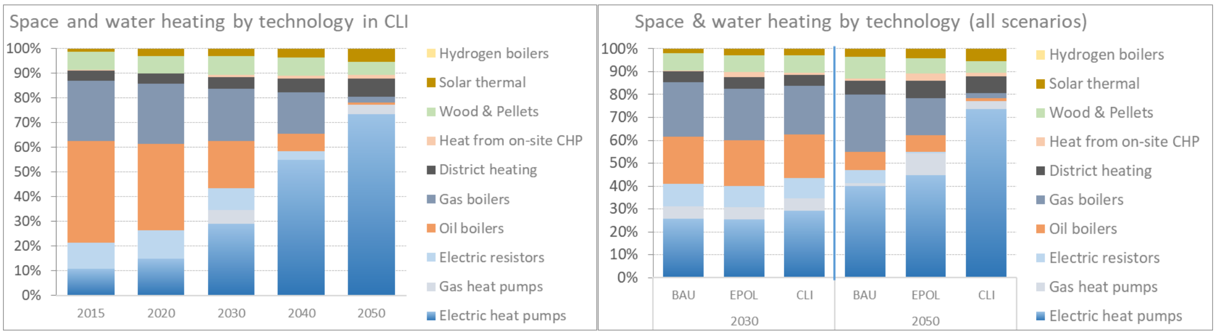


Figure 3.4: *Space and water heating by technology in the CLI scenario (left) and the other of the core scenarios (right)*

Figure 3.5 presents the total final energy consumption in the residential sector for space and water heating as well as for other end-uses, e.g. lighting, cooking, air-conditioning and information and communication technologies. The deployment of efficient equipment in buildings for heating and other applications decreases the overall final energy consumption in the residential sector from 2020 to 2050, despite increasing population and housing needs.

More specifically, in *BAU*, the residential demand plateaus until 2030 and slightly declines towards 2050, following the substitution of ageing equipment in electrical appliances and heating with more efficient options. There is a shift from oil-based heating to gas, as well as a slight increase in the penetration of wood and pellet boilers.

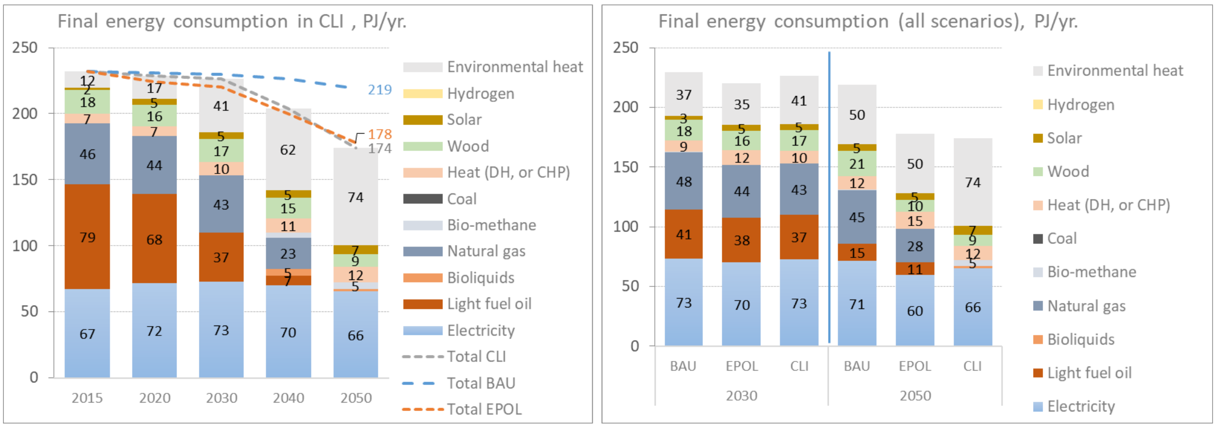
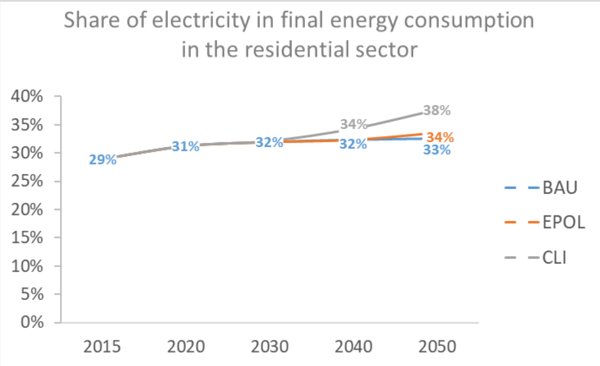


Figure 3.5: *Final energy consumption in the residential sector in the CLI scenario (left) and the three core scenarios for selected years (right), excluding consumption of on-site CHP plants*

In *EPOL*, there is a strong decline of the final energy consumption in the residential sector that starts already in the first decade of the projection horizon. The fuel mix shifts from oil to gas, at a rate higher than in *BAU*. Wood boilers are phased-out and are replaced by the more efficient pellets, reducing the overall needs for wood in the sector.

In *CLI*, the final energy consumption declines further, and achieving the net-zero ambition would require decarbonisation of the residential sector. By 2050 only zero-carbon fuels and energy carriers, including biogas and bioliquids, contribute to the provision of the space and water heating. Simultaneously, there is strong electrification accompanied by increased deployment of renewable energy compared to the other two core scenarios.

Figure 3.6 presents the share of electricity in final energy consumption in the residential sector in the three core scenarios. In *BAU* there is a plateau in the electrification after 2030, as the efficiency gains achieved by the replacement of ageing equipment partially offset the increase in the demand for heating and other uses induced by the population growth and the growth of the energy reference area. In *EPOL*, the absence of clear price signals related to efficiency or climate targets hinders the further electrification of the sector. For example, in *EPOL* the electrification is only slightly higher than in *BAU* due to the imposed targets on per capita electricity consumption. The strongest electrification of the residential sector is seen in the *CLI* scenario, due to the clear long-term price signals for efficiency and decarbonisation.



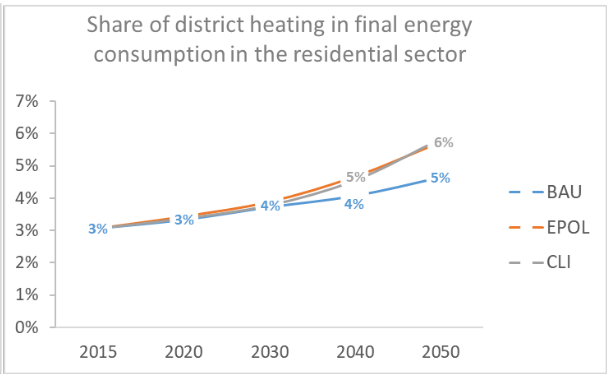


Figure 3.6: *Share of electricity (left) and consumption of district heating (right) in the residential sector*

District heating (and cooling) networks can be fed by a wide range of renewable energy sources and deliver heat for buildings and industries. District heating expands its market share in *BAU* around 5% in 2050 compared to 3% in 2015 but in *EPOL* and *CLI* scenarios its share doubles in 2050 from the levels of 2015. The switch to district heating networks would require dedicated infrastructure and sectoral integration, while in the case of the *CLI* scenario, the district heating sector would need to become increasingly efficient and decarbonised. Hence, in *CLI*, renewable energy sources such as wood, solar and geothermal, together with hydrogen in the last decade of the projection period, emerge as sources of district heat generation (see also section 6). In this context, district heating facilitates the integration of renewable resources and offers storage and balancing services to the Swiss energy system in the *CLI* scenario.

Besides the electrification and expansion of district heating networks, bioenergy plays an important role in decarbonising space and water heating applications. Together with the use of wood and pellets, with the latter gradually replacing wood boilers, biodiesel and biogas/biomethane also penetrate at a larger scale than today in the *CLI* scenario mainly after the mid-2030s, in those buildings in which the replacement of oil and gas boilers is not possible or too expensive (e.g. in the mountains or in certain historical buildings). The share of liquid and gaseous biofuels in total final energy consumption reaches 4% in 2050. Though the share seems small, it should be seen in the context that all liquid and gaseous fuels consumed in *CLI* in 2050 in the residential sector are of biogenic origin.

Figure 3.7 shows the energy consumption and the share of technologies in the supply of space heating in different building types and age classes in the *CLI* scenario. The energy consumption in existing buildings substantially declines due to the deployment of renovation and building insulation measures, on top of the demolition of the existing building stock. In contrast, the final energy consumption in new buildings increases over time. Still, the efficiency gains due to the deployment of heat pumps offset to a large extent, the growth in the energy reference area.

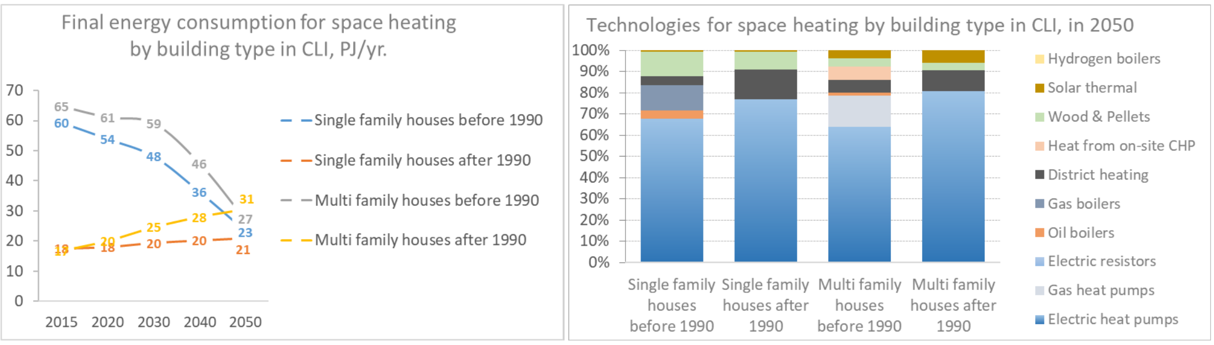


Figure 3.7: *Total final energy consumption for space heating by type of building (left), and share of technologies supplying space heating in the different building types in the CLI scenario in 2050*

3.1.2 Transition enablers, opportunities and challenges

Energy efficiency improvements in the building sector can build on a number of existing schemes: the MINERGIE ® standards can achieve the construction of near-zero-emissions buildings, while the Buildings Programme ("Gebäudeprogramm") at Federal and Cantonal levels provides the regulatory incentives to spur ambitious renovations. At the same time, energy labelling and adoption of eco-design standards steer consumers to pay more attention to the energy consumption of their appliances (Yilmaz et al., 2019).

However, the household sector analysis in the *CLI* scenario indicates that several challenges remain to be addressed. The renovations' pace needs to be significantly increased, while renovations are more difficult to envisage for tenants than for owners. Appliances would need to improve their efficiency continuously and smart technologies, as part of digitalisation, would need to be integrated to reap the benefits at a cost affordable manner for all customers. Technology progress made already certain solutions easily available to consumers (e.g. better control of indoor temperatures) and enabled a more rational use of the energy than in the past.

Such technologies that enable smart use of energy and are based on cutting edge IT solutions are perceived as promising. However, they are still costly, their uptake depends on the ease of their use, and the required infrastructure and network improvements pay-off only in the long run (IEA, 2017). It will remain a key challenge to convince consumers to embark opportunities arising from smart and more efficient use of energy (including storage) and become more active participants in the energy markets (ICF, 2017). For example, Germany has already started to address this challenge by imposing requirements for smart meters in households or smart indicators in buildings (BMWi, 2019, BWMi, 2019). Widespread automation and digitalisation, sustained by accurate and useful consumer information, and supported by targeted policies addressing the remaining behavioural biases, could affect consumer behaviour, change consumption patterns, and shape residential demand around the smart use of energy (EC, 2018).

3.2 Industry

3.2.1 Transformation pathways

Industry continues the trend of emission reductions and energy savings exhibited in the past few decades in all the three core scenarios, indicating that the continuation of current efforts and policies in the sector can achieve further emission reductions by 2050. In the *BAU* scenario, such reductions stem mainly from current trends (such as energy efficiency measures or structural changes), foreseeable technological developments, mega-trends such as digitalisation and automation, and existing measures and policies. However, the developments in *BAU* cannot deliver the envisaged levels of ambition despite the substantial reductions in energy and CO_2 intensity in industry (see figure 3.8).

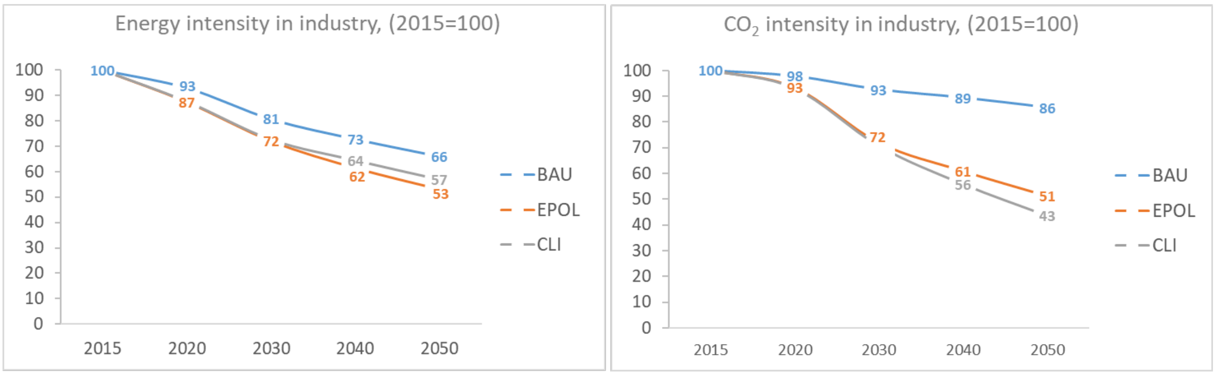


Figure 3.8: *Improvement in energy intensity (unit of gross industrial value added produced per unit of energy consumed), and in CO_2 intensity (unit of emissions per unit of energy consumed)*

To further and deeply reduce its emissions, especially in line with a net-zero ambition in 2050, major changes need to be made in the way industry consumes and produces products. In order also to maintain a competitive industrial activity, the energy and CO_2 intensity of industry need to be almost halved in 2050 compared to 2015 levels. For such high levels of ambition, CO_2 capture and storage need to be deployed to at least offset emissions from industrial processes, especially in the cement sector. Together with CCS increased use of biomass, electrification, and accelerated penetration of best available technologies (BAT) play a critical role in reducing the emissions in industry.

The menu of options to decarbonise the industrial sector includes: a) demand-side management measures to lower the demand for primary resources by increasing circularity; b) energy efficiency by adapting the production to lower energy use per produced volume; c) electrification of heat by replacing fossil fuel for heating with renewable electricity; d) hydrogen as a feedstock or to replace fossil fuels for the supply of electricity and heat; e) the use of biomass as a feedstock or to replace fossil fuels for electricity and heat supply; f) the deployment of CO_2 capture and storage, including also possible utilisation of the captured CO_2 g) deployment of solar thermal for the supply of heat; g) other innovative processes such as electrochemical production processes and non-fossil fuel feedstock change (e.g. change in cement feedstock). From the above options, currently, energy efficiency and electrification of industrial heat production seem to be the most technologically mature options for further reducing energy-related industrial emissions. Other fuel-switching options, e.g. biomass, hydrogen, and e-fuels, do exist but at various technological readiness levels. It should be noted that the electrification of process heat also has a high potential, but not horizontally across all industrial sectors. Today it is deployed in the non-ferrous metals and chemical industries. Some further potential also exists in electrochemical processes in the chemicals sectors, as well as electrolysis and electric arc in the iron and steel sector. However, further research is required to increase the technology readiness of these solutions.

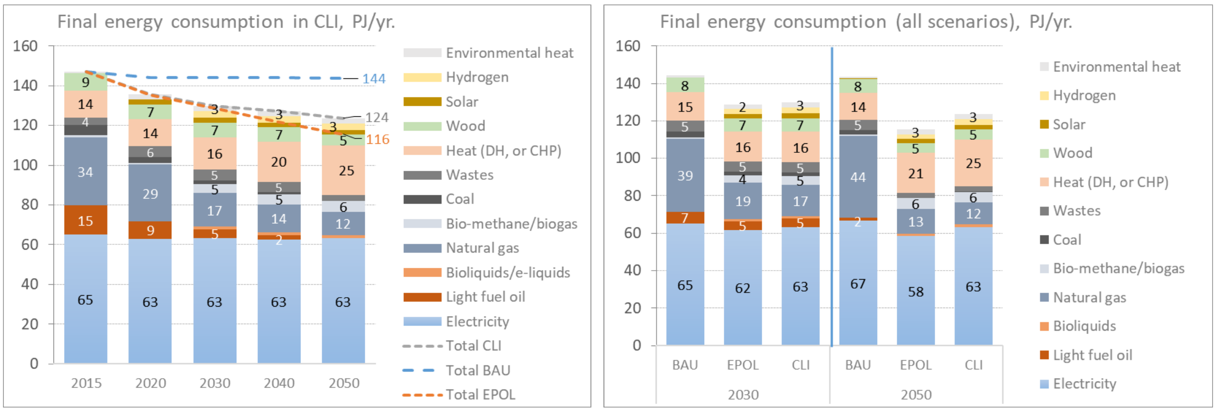


__Figure 3.9:__ Final energy consumption in industry in the CLI scenario (left) and the three core scenarios (right). The fuel consumption in on-site CHP plants in industry is not included

The industrial transition is built around the aforementioned decarbonisation options, and it is supported by the sustainable supply of raw materials, optimised material flows in cross-sectoral value chains, energy resource and efficiency, and demand-side management measures to stimulate the creation and fast development of markets for low- and zero-carbon industrial products and solutions. As a result, the total final energy consumption in industry is projected to decrease in all scenarios, despite the expected increase in industrial output (figure 3.9). The highest reductions are observed in *EPOL* and *CLI*, which deploy increased efficiency measures, including circular economy strategies. As already mentioned at the beginning of this section, the final energy consumption in *CLI* is higher than in *EPOL* in the last decades of the projection due to increased energy needs for operating carbon capture filters in industrial facilities (other than CHP, e.g., in the cement industry). By excluding the fuel consumed for the operation of CCS in industry, the energy savings achieved in the *CLI* scenario are of a similar magnitude with the ones achieved in *EPOL*.

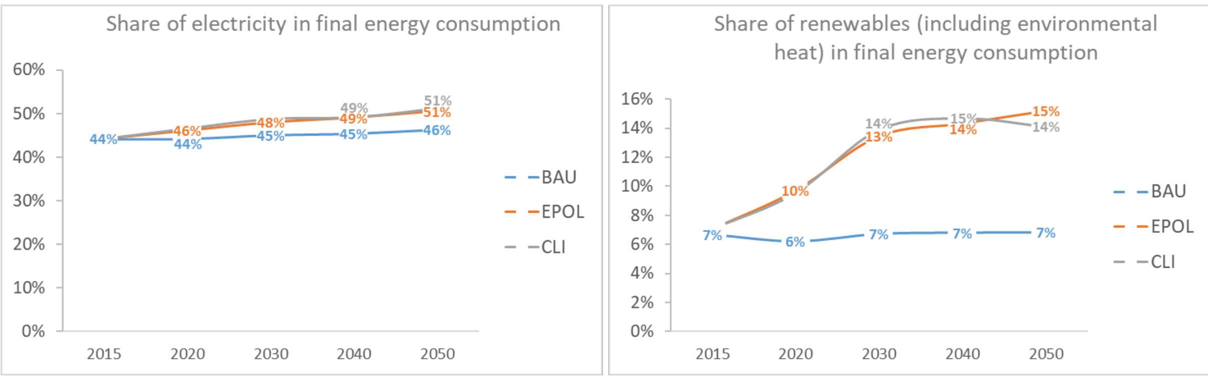


__Figure 3.10:__ Share of electricity (left) and share of renewable energy (right) in the total final energy consumption in industry

In the *CLI* scenario, there is a shift in the fuel mix away from fossil fuels towards renewables and electrification (figure 3.10). Those industrial uses that are hard to electrify or require combustible fuels to produce heat at high-temperature levels shift to zero-carbon gases, such as biomethane and hydrogen, to the extent possible as there is competition for these resources also from other sectors of the energy system. Wood consumption remains largely on today's consumption levels thanks to the increased deployment of more efficient equipment (e.g. pellets).

There is a substantial increase in heat consumption from on-site cogeneration, especially in *EPOL* and *CLI* scenarios. CHP plants contribute to efficiency gains, and if they are fuelled with low-carbon fuels, and equipped with CCS (the large scale CHPs), they can have a positive contribution in achieving the climate targets. In this regard, in the *CLI* scenario, CCS in industry occurs in the cement production and large scale CHP installations burning gas or wastes.

The use of the CC(U)S in industrial processes comes at increased energy consumption. In the cement sector alone, the operation of CCS filters is responsible for about 5 PJ increase in the fuel consumption in 2050 in the *CLI* scenario. This additional energy refers mainly to electricity and heat (waste heat is not shown in figure 3.9). The additional consumption due to the operation of carbon capture is also the reason for the reduction of the renewable energy share in total final energy consumption in industry beyond 2030 in the *CLI* scenario shown figure 3.10, despite the increase in the consumption of renewable energy in absolute terms.

Cogeneration in industry plays an increased role in the next decades and particularly after the nuclear phase-out when no other large-scale generation option is deployed (e.g. gas turbine combined cycle power plants). Hence, in the *BAU* scenario the electricity production from on-site industrial CHP plants remains almost constant during the entire projection period, as large scale gas-based generation fills the electricity supply gap due to the nuclear phase-out.

However, in *EPOL* and *CLI* scenarios, where no such large scale central fossil generation is deployed, the decentralised on-site electricity production doubles (in *EPOL*) or even quadruples (in *CLI*) in 2050 from its 2015 levels. This also leads to a substantial increase in the consumption of heat generated from on-site CHP plants, which in turn contributes to significant efficiency gains in industry, as shown in figure 3.11.

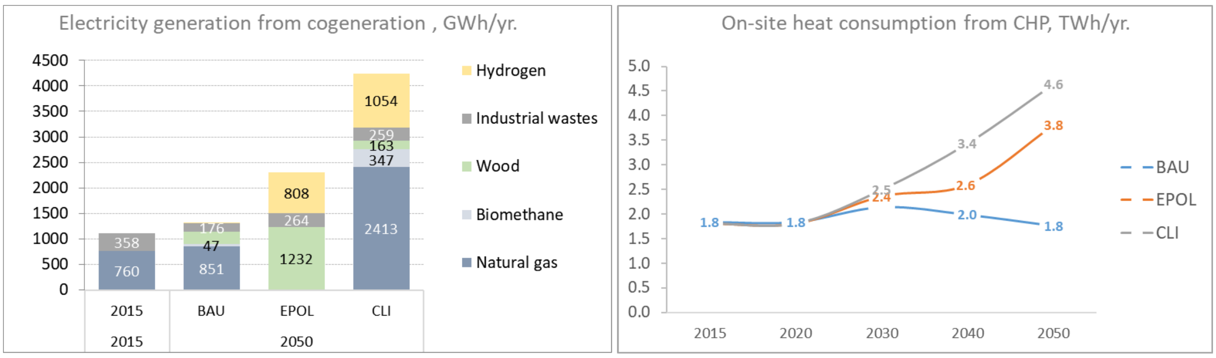


Figure 3.11: *Electricity production generated by on-site CHP plants in industry (left) and quantities of heat produced by CHP plants in industry and consumed on-site (right)*

3.2.2 Transition enablers, opportunities and challenges

The transition in industry will generate both technology deployment and cost challenges and may involve earlier depreciation of assets in emission-intensive technologies. The necessary shift away from fossil fuels for industrial heating and processes will make many industries increasingly electricity-intensive.

Moreover, without the transformation of energy supply, the decarbonisation of industry will be impossible. The required emissions reductions in industry are closely linked with the further development of low carbon technologies, increased electrification of process heat, use of biomass/hydrogen, CO_2 carbon capture and storage, and energy savings measures (Zuberi et al., 2020), as the deployed Best Available Technologies (BAT) can deliver only limited emission reduction (ICF, 2015).

The decarbonisation policies cannot be implemented, and innovative solutions cannot be deployed without an extensive network of adequate infrastructure to fully support the major trends framing the future energy landscape in industry: electrification and storage, use of alternative zero-carbon fuels and alternative industrial feedstock, decentralisation/distribution, digitalisation, material efficiency, sustainable supply of raw materials, optimised material flows supporting circular economy and industrial symbiosis, as well as new market designs (Wyns, T., Khandekar, G., Robson, 2018).

The analysis suggests that the speed of penetration and deployment of key decarbonisation technologies in industry is critical. However, the penetration of the key transition technologies and options identified above in many industrial sectors is not so straightforward as many industrial plants are large, tailor-made and often part of complex industrial systems that are difficult to change, while innovative technologies themselves often are rarely suited for retrofitting (Obrist et al., 2021). An opportunity can arise from the timely replacement of ageing infrastructure and assets with highly efficient ones that contribute to decarbonisation. Such an opportunity can be attractive only when the investors receive suitable long-term price signals from the policymakers.

A policy framework is needed that enables investment in supporting the industrial transition, and which can mitigate the risk of creating stranded assets and threatening the competitiveness of Swiss industry. Such a framework can facilitate differentiation and encourage markets and public to recognise the value of higher-priced, but of low-carbon content, industrial products (Young et al., 2010).

However, industrial policy can only partially support industry's transition to competitive GHG neutrality. It needs to be also accompanied by additional measures. These could include a supportive trade policy, the creation of a suitable investment environment, efficient taxation, research and innovation, as well as coordinated regional policies and access to energy infrastructures (EC, 2018).

The results from STEM show that it is important to ensure that these policy frameworks are in place as early as possible. The investments in industry are capital intensive and are characterised by long lifetimes and inertia in replacing industrial plants. The industrial investments made in the next ten years will most likely continue to be in place also in 2050. As the analysis with STEM suggests, the timing of coordinated industrial actions and policies become more important when ambition increases.

3.3 Services

3.3.1 Transformation pathways

The socioeconomic activity drivers are pushing the energy demand up in the services sector over time. However, building renovation and improvements in the energy performance of heating and cooling equipment, improvement of the efficiency of appliances, and penetration of building automation, control and smart systems (BACS), drive demand reductions in the long term. Figure 3.12 shows that the fuel and technology switch delivers energy savings as a result of the continuous replacement of the ageing stock. Also, in *EPOL* and *CLI* scenarios, there is a substantial implementation of energy conservation measures to meet efficiency and emissions targets. In fact, the energy savings in *CLI* are significantly higher than the ones achieved in *EPOL*.

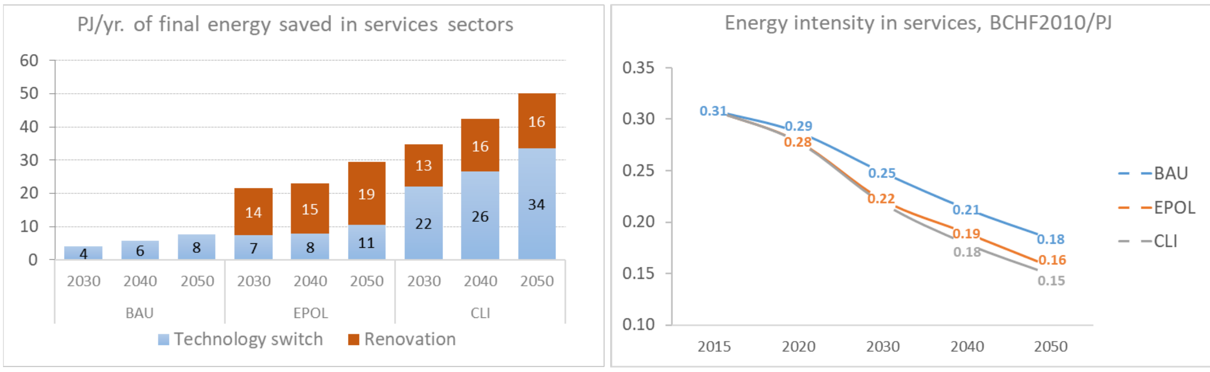


Figure 3.12: *Efficiency gains through technology switching and energy conservation (left), and energy intensity in services in terms of a unit of gross value added to a unit of energy consumption*

In this regard, the final energy consumption is lower in 2050 than in 2015 in all scenarios (figure 3.13), due to the continuous upgrade of heating, cooling and electrical appliances, as well as the improvement of the thermal integrity of the building shells. Schools, restaurants and commercial buildings (including buildings hosting institutions providing financing services) contribute most to reducing the final energy consumption, as administrative buildings and hospitals already today implement energy conservation measures.

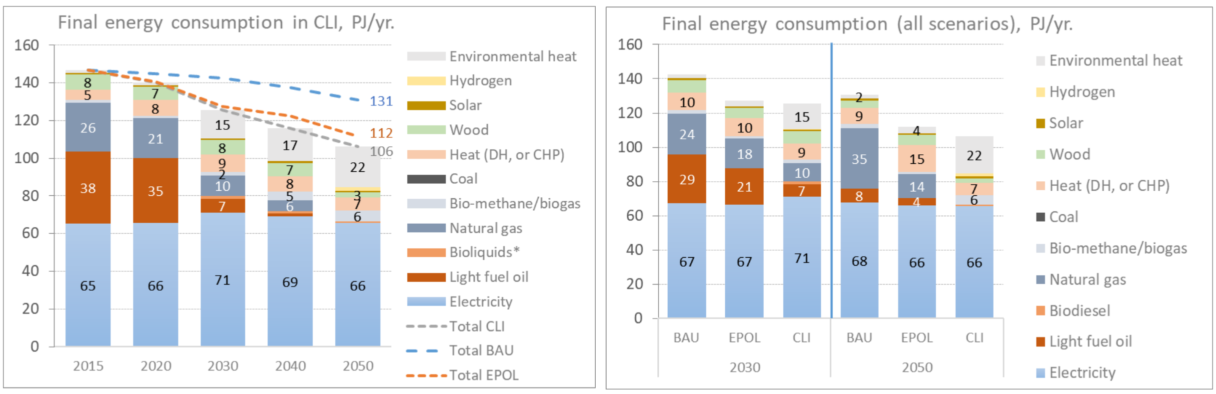


Figure 3.13: *Final energy consumption in the services sector in the CLI scenario (left) and the three core scenarios for selected years (right). Fuel consumption in on-site CHP plants is not included, as this is accounted for in the power generation*

In all scenarios, there is a shift away from oil. The shift is more prominent in *CLI*, where any remaining oil is mostly of synthetic or biogenic origin, and it is consumed in those sectors in which electrification or penetration of renewables is not possible. These include, for example, restaurants in mountainous areas or commercial buildings in historic city centres. In *BAU* and *EPOL* scenarios, oil is substituted mainly by gas (except of course in those areas where the gas network is not available).

While natural gas sees an expansion in those scenarios throughout the whole projection period, in *CLI* it serves mostly as a transition option until 2040. Thus, in the last decade of the *CLI* scenario, the supply of heat in services sectors is fully decarbonised via increased electrification and penetration of renewable energy (figure 3.14). Natural gas is substituted by biomethane and biogas in those uses in which electrification is not possible, or they need gaseous fuels. Biomethane and biogas account for about 5% in final energy consumption in 2050 in *CLI*, from only 1% in 2015.

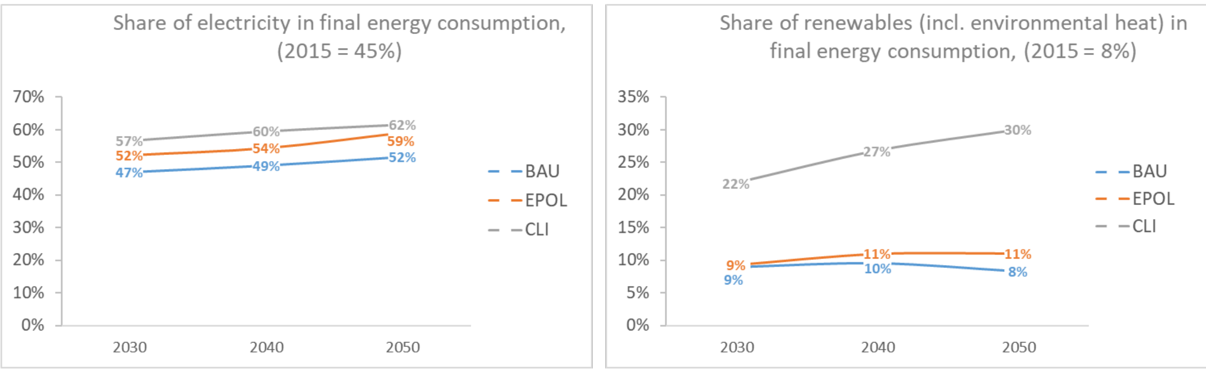


Figure 3.14: *Share of electricity in final energy consumption (left) and share of renewable energy (right) relative to 2015*

Finally, the share of district heating in the overall heat supply in services increases in all scenarios in 2050 from 2015 (figure 3.15). During the last decade of the projection period, there is a deceleration of the growth of district heating consumption, especially in *CLI* and *EPOL* scenarios where efficiency measures are substantially deployed compared to *BAU*.

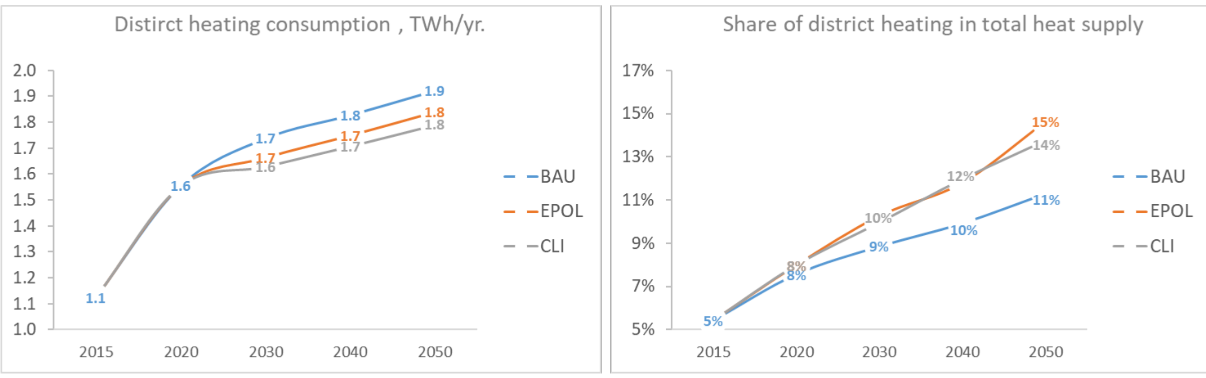


Figure 3.15: *Consumption of heat from district heating networks in services (left) and share of district heating in total heat supply in the services sector (right)*

3.3.2 Transition enablers, opportunities and challenges

The main challenge in the energy transition in the services sectors lies in achieving the required reductions in energy consumption in buildings. The buildings' nature in services is that landlords develop and own them, while firms and small enterprises lease them. Long-term leases of ten years, or more, provide little incentives to improve building efficiency and reduce carbon emissions. Hence, there is a failure of effectively distributing financial obligations and benefits between the concerned actors (Economidou and Bertoldi, 2015).

This "split of incentives" between owners and tenants often leads to locked-in performance of the building for at least a decade. Regular communication between these two groups of stakeholders around a joint vision to reduce carbon emissions is important. Some building upgrades, such as lighting systems, smart metering and solar panel installations can benefit both the tenant and landlord if discussed and worked through, with a common vision for the building.

Another measure that could apply besides avoiding the split of incentives between tenants and landlords are the so-called "green leases". For example, tenants require the landlord to provide a base building that achieves a certain rating in the MINERGIE® or other energy performance standard. Improving tenant awareness and embedding a variety of environmental incentives in the workplace, including energy efficiency, will assist in achieving the energy and emissions reductions needed towards a net-zero energy system in 2050.

In general, the following areas can be identified where increased focus could accelerate the change in the services and commercial sectors (Oldfield et al., 2019):

- Government and administration buildings can be the frontrunners in reducing energy consumption and carbon footprint.
- Awareness, information sharing and training of commercial tenants of various sizes, regarding building renovations that can benefit them to optimise and improve the energy efficiency of their space and their behaviour on how they use the space.
- Enhancing the building standards in place by providing a clear trajectory towards carbon neutral performance, so that owners and tenants can respond and plan accordingly.
- Improving passive design and construction features of commercial buildings and supporting new technologies such as building-integrated solar panels, and demand management

Many tenants in commercial buildings lack real-time insight on energy use. Privacy concerns can hinder deployment of smart meters, and new hardware and software will be needed to help commercial users benchmark their consumption against peers and make informed decisions. Still, upfront costs could be an obstacle to switching existing buildings to alternative low-carbon technologies and smart energy use solutions. Streamlined loan processes, rebates, tax credits, favourable loan terms can be a few of the financial support measures that can be pursued to lift the investment barrier.

3.4 Transport

3.4.1 Transformation pathways

Today transport accounts for about one-third of the final energy consumption in Switzerland, dominated by technologies that rely on liquid fossil fuels. In 2050, in all the three scenarios, the share of conventional technologies is projected to decline. However, there is no single solution for future low-emission mobility. There are different modes with different needs, which implies that all technologies have their place in the years to come. Towards net-zero emissions in 2050, all main alternative energies for transport are pursued, focusing on each transport mode's specific needs.

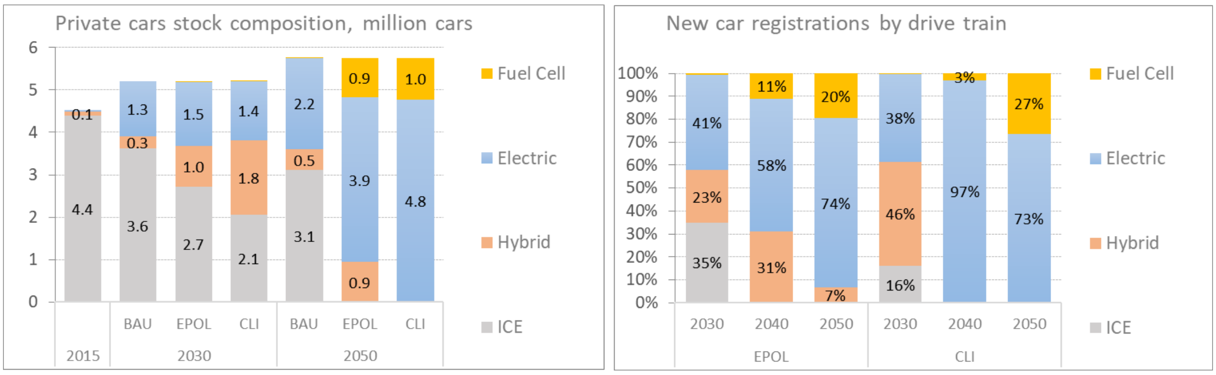


Figure 3.16: *Composition of private car fleet (left), and share of drive trains in new private car registrations. ICE refers to Internal Combustion Engine vehicles fuelled by gasoline, diesel, natural gas and biofuels. Electric refers to both plugin and battery electric vehicles where plugins can be fuelled by gasoline, diesel, biofuels and synfuels. Fuel cell electric vehicles are based on hydrogen*

In **private cars**, electric vehicles are evolving as a cost-efficient mobility option, due to the fast developments in improving the driving ranges and charging times, even in the case of the *BAU* scenario where the climate change mitigation is not the primary priority (figure 3.16).

In *CLI*, there are about 4.8 million electric cars in 2050 (about 83% of the fleet), of which 3.1 million are battery-electric, and the remaining are plug-in electric. Achieving the net-zero scenario requires that the plug-in vehicles in 2050 are fuelled by biofuels or synthetic fuels produced with Carbon Capture and Storage (CCS), which results in direct net emissions from the car fleet becoming at least carbon neutral. In *CLI*, hydrogen fuel cell cars constitute the remaining 17% of the fleet.

Strong electrification of the private cars fleet also occurs in *EPOL*, driven by the priority in this scenario to reap the largest possible efficiency gains. In the absence of a strong climate change mitigation policy in *EPOL*, plug-ins and battery-electric cars have an almost equal market share by 2050, which is not the case in the *CLI* scenario, where battery-electric cars dominate. Another important difference of *EPOL* compared to *CLI* is that in the absence of climate change mitigation incentives, the plug-in cars in *EPOL* are fuelled by fossil fuels compared to the zero-carbon fuels (i.e. biofuels and synthetic e-fuels) in *CLI*. Thus, the lack of long-term price signals for fuel switching, combined with the overarching target in reducing the electricity consumption per capita in *EPOL*, hinder electrification of the transport sector, which does not reach the levels seen in the *CLI* scenario.

Nevertheless, plug-in hybrids constitute an important transition technology in both *EPOL* and *CLI* scenarios, as shown in figure 3.17, which displays their shares in the total private car fleet. The penetration of plug-in vehicles peaks around 2040, and helps in achieving a large scale availability of recharging stations. This paves the way for the increased uptake of battery-electric cars in the last decade in both scenarios.

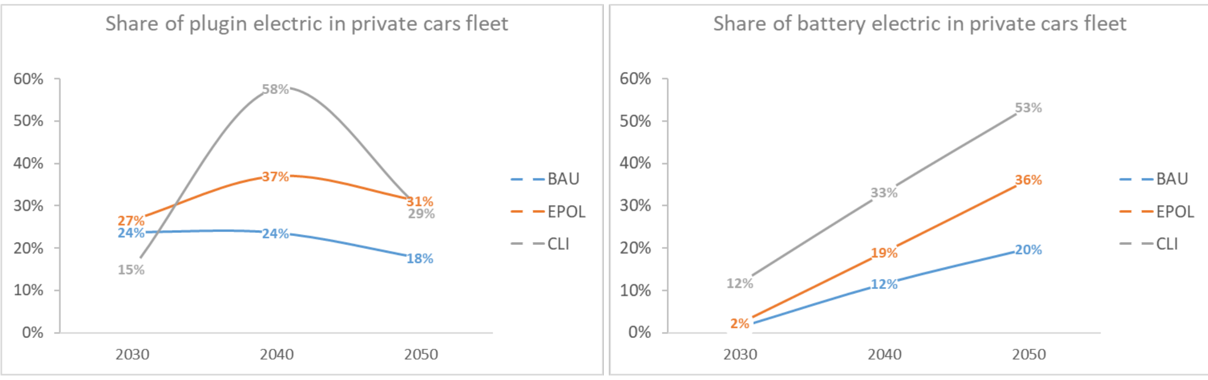


Figure 3.17: *Share of plugin hybrid electric private cars in the stock (left) and battery-electric (right)*

As shown in figure 3.16, the path to electrification in all scenarios goes in the middle term through a strong expansion of hybrid vehicles, which act as bridging technologies, until a large-scale roll-out of recharging infrastructures and improvements in battery performance (costs, ranges) are achieved that enable higher penetration of pure battery-electric vehicles. In *CLI*, the period from now until 2050 is divided into three principal stages: a) the period until 2030 is characterised by transition with many options competing; b) the period 2030 – 2040 which sees a rapid introduction of electric vehicles; and c) the period 2040 – 2050 in which fuel cell cars emerge and gain share in the market, while electric vehicles continue to grow. The last two decades are characterised by a rapid transformation of the private cars sector, mainly driven by the take-off of electric cars, including fuel-cell vehicles.

The hybridisation of **buses, Light Duty Vehicles (LDV) and trucks** emerges as a competitive option also without stringent climate change mitigation measures (see also figure 3.18). Unlike cars, extensive electrification of trucks beyond hybridisation is more expensive because of high energy densities needed for batteries and longer annual mileages.

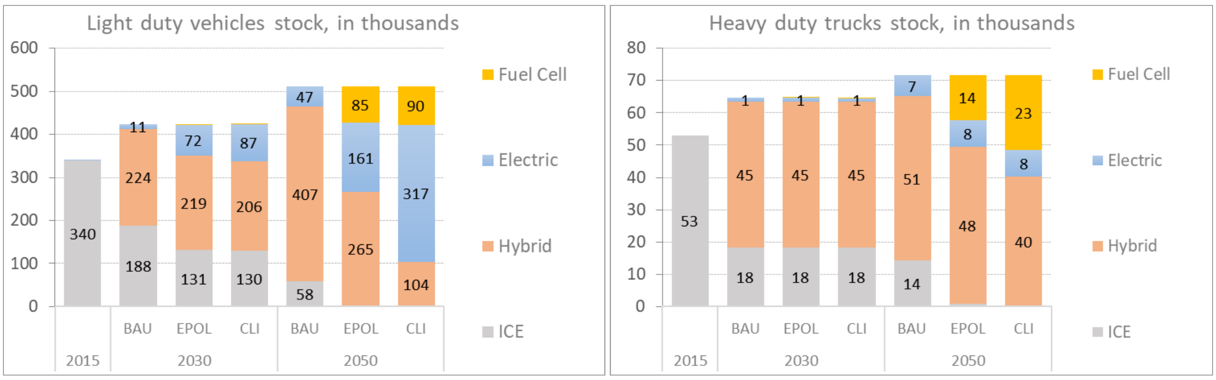


Figure 3.18: *Composition of the stock of light-duty vehicles (left) and heavy-duty trucks (right)*

This calls for ambitious climate policy measures. Under such conditions, LDVs and urban buses become extensively electrified. Major deployment of electric trucks occurs only when stringent emission performance or fuel-efficiency standards are enforced, or carbon taxes are levied on transport fossil fuels, or battery costs can be pushed below currently projected costs. To achieve the ambitious climate goals, a part of the medium size trucks become battery-electric due to their lower payload and short-haul trips. In the *CLI* scenario hydrogen provides significant contributions in all segments mentioned above. Heavy-duty trucks turn to hybrid internal combustion trucks powered by biofuels and imported synthetic e-fuels (Power to Liquid - PtL). Uptake of fuel cell trucks occurs when emissions or efficiency standards are in place, or if most ambitious climate goals are to be achieved for heavy-duty road-transport segments where direct electrification is limited or impracticable.

A strategic approach to lower emissions from the mobility sector also needs to fully exploit the potential for improving vehicle efficiency in conventional and alternative fuel vehicles. Engine efficiency improvements, aerodynamics improvements and drag reduction, engine hybridisation of various forms, as well as plug-in hybridisation and range extension, will continue to play a role as shown in figure 3.19.

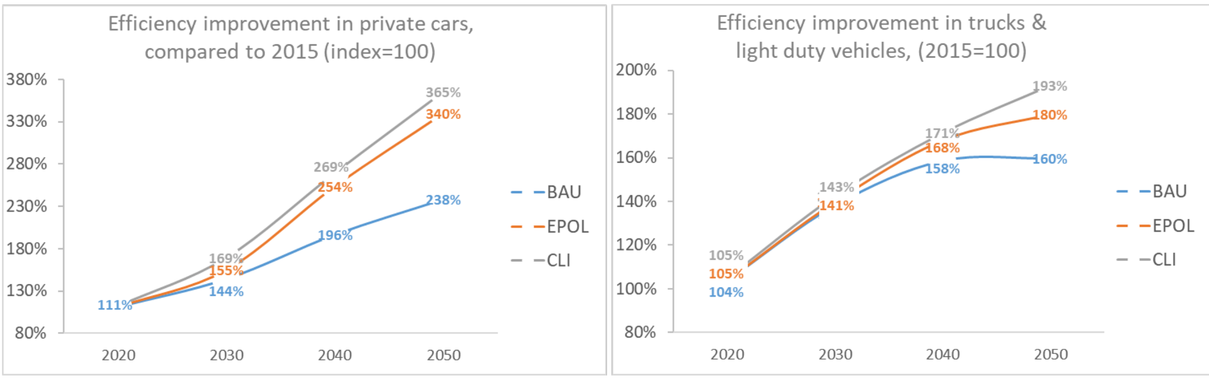


Figure 3.19: *Efficiency improvement as total kilometres driven vs total fuel consumption across the vehicle stock, for private cars (left), light-duty vehicles & trucks (right), compared to 2015*

On top of the technical progress in improving vehicle efficiency, efficiency gains in transport are also achieved (and accelerated) by the technology switch to low- and zero-emission vehicles based on batteries. Battery electric vehicles are a strong enabler of efficiency in energy use for vehicle propulsion and also offer novel vehicle design possibilities. As electric vehicles, i.e. plug-in hybrids, battery-electric and fuel cells, become increasingly important across the scenarios, there are significant improvements in the tank-to-wheel fuel efficiency at the fleet level. Larger energy savings are achieved for passenger transport rather than for freight transport in 2050.

The *BAU* scenario shows the transport energy consumption (excluding international aviation) decreasing in 2050 compared to 2015 levels, due to the technical efficiency improvements in different powertrains and switch to non-conventional vehicles, mainly hybrids. However, in *BAU*, fossil liquids remain the dominant fuel in the transport sectors. In contrast, in *EPOL* and *CLI* scenarios, the need for meeting the stringent efficiency and climate targets induces a significant reduction in fuel consumption in transport. While in *EPOL* fossil fuels still play an important role, in the *CLI* scenario, the transport sector is almost fully decarbonised (figure 3.20).

In *CLI*, achieving the net-zero emissions target by 2050 would require that the mobility sectors shift away from carbon-intensive fossil fuels. Electricity, hydrogen, and zero-carbon fuels (mostly imported bioliquids or synthetic e-fuels produced with renewable electricity and CO_2 capture) are enablers of decarbonisation. The share of electricity in total fuel consumption in transport reaches almost 50% in the *CLI* scenario by 2050, from only 5% today, without including the electricity for producing hydrogen consumed in fuel cell vehicles. Liquid biofuels and e-fuels are projected to increase in the *CLI* scenario and account for one-third in the total final energy consumption in mobility. The transport modes that have fewer options to decarbonise, such as the long-distance heavy goods transport, opt for liquid biofuels and e-fuels.

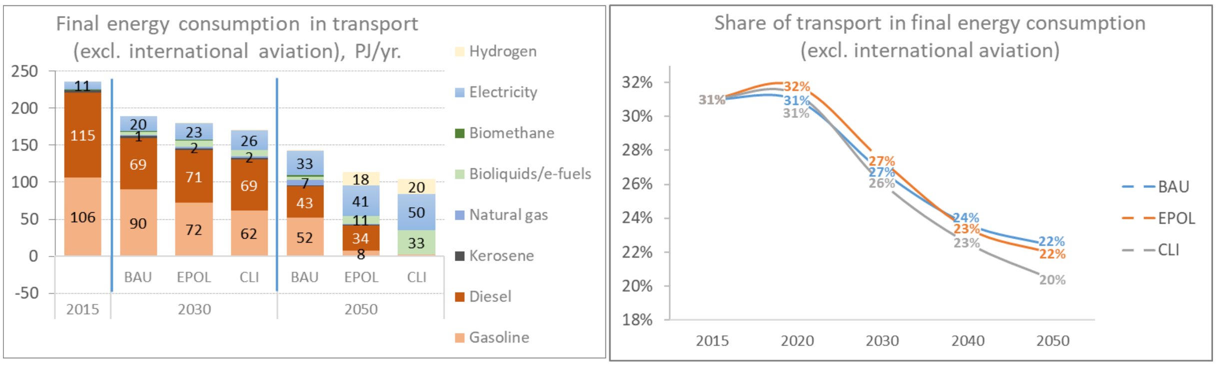


Figure 3.20: *Final energy consumption in transport excluding international aviation (left) and share of transport fuel consumption in total final energy consumption (right). Bioliquids/e-fuels refer to both domestically produced biofuels and imported zero-carbon fuels of biogenic or synthetic origin*

Hydrogen becomes part of the transport fuel mix, with a share approaching 20% in 2050. The bulk of hydrogen consumption occurs in private cars due to the large size of this mobility segment. However, the penetration of hydrogen vehicles is the largest in long-distance public passenger and freight transport, when looking at the market shares of vehicles. Yet, these two fleet segments account for only a small fraction of the total energy consumption in road transport.

The substantial transformation of the transport sector in all the three core scenarios, and in particular in *EPOL* and *CLI*, decreases its share in the total final energy consumption of the Swiss energy system from the levels of today. As it is also shown in both figures 3.2 and 3.20, transport, and in particular road private transport, delivers in both *EPOL* and *CLI* scenarios the largest energy reductions after the residential sector over the period of 2015 to 2050.

3.4.2 Transition enablers, opportunities and challenges

Attaining deep emissions reductions in transport, under a sustained growth of the mobility demand, requires a broad range of measures. These include gains in transport system efficiency, deployment of low- and zero-emissions vehicles, modal shift and multi-modality (Mathys and Justen, 2016).

Road transport is almost fully decarbonised. There is a need to maintain and support the growing momentum for battery-electric vehicles until other zero-carbon options, e.g. hydrogen fuel cells, also become available. The use of biofuels and e-fuels as a transition technology is a promising alternative, because of the important advantage of their direct use in conventional engines and reliance on existing refuelling infrastructures. However, e-fuels require a significant amount of electricity for their production, their lifecycle emissions depends on the source of carbon used (Liu et al., 2020), while there is also an uncertainty regarding the reduction of their production cost and the pace of deployment of carbon capture options. At the same time, biofuels also face land constraints and food security issues (FAO, 2010, Hamelinck, 2013). Thus, the transport modes where e-fuels and biofuels will be deployed need to be carefully considered, and aviation can be a good case (McKinsey, 2020).

While in private cars and light goods transport the electric-vehicles are competitive decarbonisation options with the conventional technologies, for heavy-duty road freight transport the transition requires continued development of a mix of technologies, including electrification, particularly for short-haul freight transport, but also advanced biofuels/e-fuels, hydrogen fuel cells and also gases (as a bridging option). Where it is technically and economically possible, a transition of the heavy-duty trucks mostly based on electrification and hydrogen instead of biofuels and e-fuels could mitigate the stress on land and energy resources.

The analysis also shows that the pace of road transport transition to low- and zero-carbon vehicles accelerates in the post-2030 period. Technological lock-ins need to be avoided, while infrastructure needs to be developed quickly and be open and easily accessible to all consumers. Consumers should receive right signals regarding their choices in mobility, and emissions standards for vehicles can help in fostering the technical and infrastructure developments needed in the post-2020 period. Impediments such as market barriers and failures, information gaps, or lack of internalisation of externalities and certainty about the future could hinder the uptake of alternative vehicle technologies, if they are not timely handled. However, if they are well channelled then the energy transition in transport could also result in large co-benefits for pollution, noise, congestion and accidents, thereby not only mitigating the climate change but also improving the quality of life, especially in cities (EC, 2018).

Application of STEM in the context of the SCCER Mobility (SCCER Efficient Technologies for Mobility, 2020) and the DEEDS project (Velazquez et al., 2020) showed that besides technological progress there is also need for new societal developments, consumer choices and innovation. Digitalisation, connected and automated mobility, mobility as a service, and efficient development of multi-modality, can support the transition and these topics can be an important part of the agenda.

Finally, stronger integration of transport with the energy system is essential. Enabling smart charging and discharging of vehicles users can generate cost savings for consumers, help the management of the energy transition, provide flexibility to the system, and enable new consumer services.

Chapter 4

Role of biomass, hydrogen and synfuels

The energy transition to a net-zero energy system in 2050 relies on substantial use of biomass and synthetic fuels. This section provides some insights regarding their role in the future Swiss energy system and highlights key challenges and opportunities surrounding their penetration.

4.1 Domestic Bioenergy

4.1.1 Supply and consumption

The exploitation of the domestic bioenergy resources, namely wood, manure and renewable wastes (in the discussion in this section we exclude industrial waste as well as the non-renewable part of the municipal waste), increases in all scenarios over the projection period, driven by current trends (*BAU*), renewable mandates (*EPOL*) as well as strong climate policy (*CLI*). Achieving the net-zero emissions target by 2050 would require exploiting the full remaining sustainable potential of bioenergy in Switzerland (figure 4.1). In such a stringent scenario, bioenergy plays a central role in addressing many challenges in the energy system: it contributes in achieving negative emissions (see section 7), it provides zero-carbon fuels for electricity, heat and transport, and it provides flexibility to the energy system in balancing intermitted renewables via flexible operation of biogenic cogeneration supported with storage.

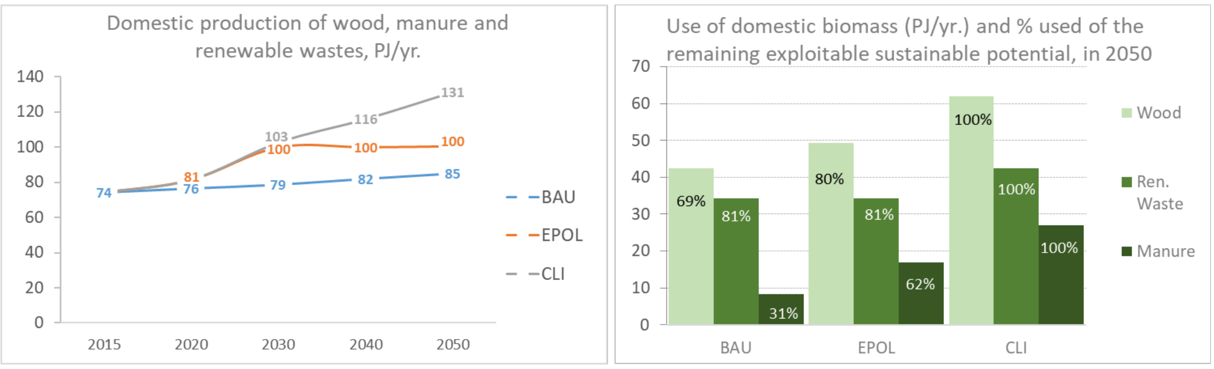


Figure 4.1: *Domestic primary production of total wood, wastes and manure (left), and breakdown by resource in 2050 (right). The percentages on the right-hand side chart refer to the rate of use of the remaining sustainable exploitable potential for each domestic resource*

Looking at the use of the various bioenergy resources in the three core scenarios (figure 4.2), woody biomass slightly expands in *BAU* and *EPOL* scenarios in 2050, compared to 2015 levels. In *BAU* the increase in woody biomass is mainly from waste wood, while in *EPOL* is also attributable to higher exploitation of the remaining sustainable potential of forest wood. The bulk of the increase in overall bioenergy use in both *BAU* and *EPOL* scenarios is mainly attributable to the increased use of manure for biogas production. In *BAU*, the production of biogas from manure is about two times higher in 2050 than in 2015, which mainly reflects extrapolation of current trends (the production of domestic biogas has increased by 74% between 2010 and 2019). In *EPOL*, biogas production from manure is about four times higher than today. It is also driven by minimum requirements in renewable energy in electricity and heat generation, according to the renewable targets imposed in this scenario.

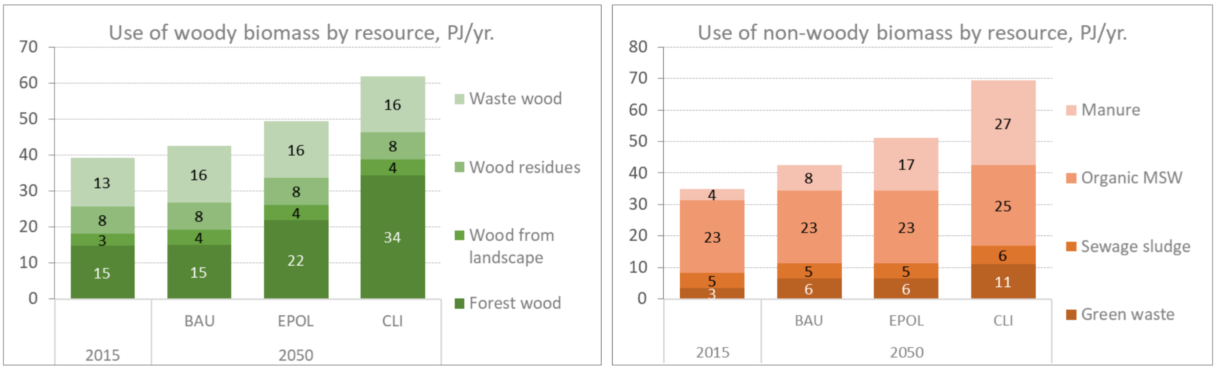
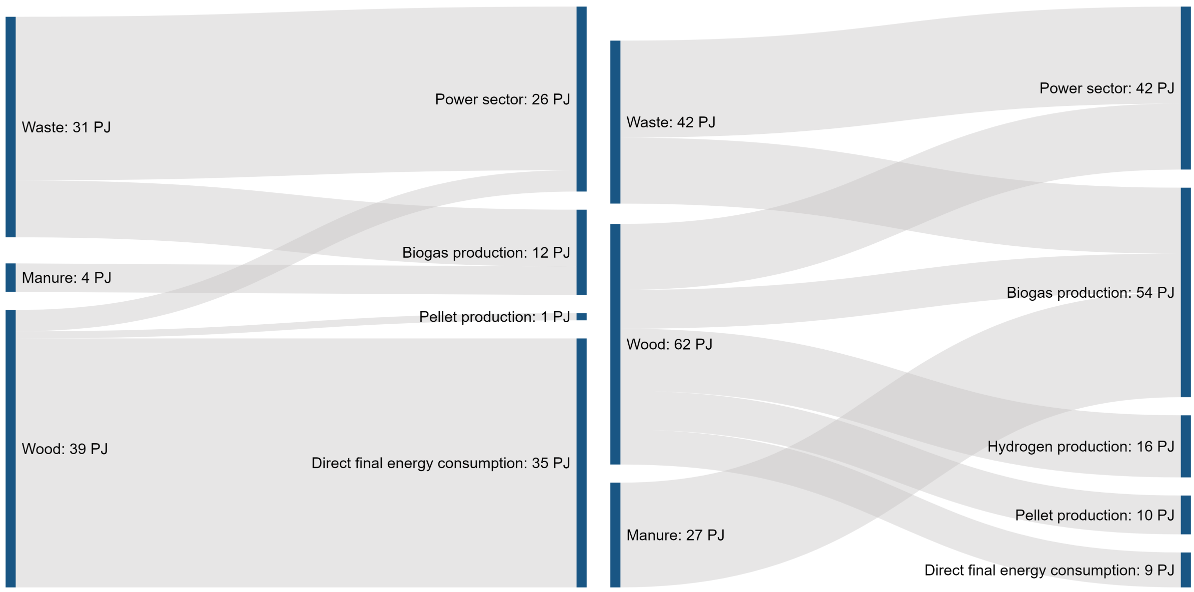


Figure 4.2: *Domestic primary production of total wood, wastes and manure (left), and breakdown by resource in 2050 (right). The percentages on the right-hand side chart refer to the rate of use of the remaining sustainable exploitable potential for each domestic resource*

However, when it comes to achieving the net-zero emissions in 2050 ambition in the *CLI* scenario, full exploitation of the available biomass resources is required (figure 4.1 and figure 4.2). The use of forest wood increases to its exploitable sustainable potential, as wood plays a central role in delivering negative emissions when it is used in technologies with carbon capture and storage. Manure utilisation for biogas production also increases to its maximum potential, to be able to supply those end-uses requiring zero-carbon alternative fuels. Imports of biogas are uncertain and equally (if not more) expensive than domestic production from manure, see also (Guidati et al., 2020). The organic municipal waste and green waste for electricity and heat production is also of critical importance, because of the possibility for negative emissions, when its use is combined with carbon capture (and storage). In this context, the *CLI* scenario requires lifting market barriers for the use of manure and improving logistics for collecting organic municipal and green wastes. At the same time new concepts in waste treatment, such as hydrothermal gasification of wastes (also combined with CCS) reach commercial scales and deployed from the mid of 2030s.

As shown in figure 4.3, the increased consumption of biomass in the *CLI* scenario is also associated with new uses of bioenergy in 2050. While today bioenergy is mainly used in electricity and heat production, by 2050 bioenergy is also used to produce hydrogen and biofuels (liquids or gases). The use of bioenergy in hydrogen and synthetic fuels production is combined with CCS to deliver negative emissions. Moreover, there is a shift in the space and process heating supplied by woody biomass, from wood chips and firewood to wood pellets, as the domestic production of pellets becomes almost ten times higher in 2050 compared to 2015. Wood pellets have the advantage of higher energy density, efficiency, easier storage and distribution, compared to wood chips and firewood.



(a) *2015* ***(b)*** *2050*

Figure 4.3: *Bioenergy use in 2015 (left) and in 2050 (right) in the CLI scenario. The flows on the right-hand side of the Sankey diagram are inputs to the corresponding conversion and end-use sectors*

In the *CLI* scenario, biogenic CHPs (including only the renewable part of waste in the waste incinerator plants) deliver around 2.9 TWh/yr. electricity in 2050 compared to 1.6 TWh/yr. in 2015. When accounting also the electricity produced from fuel cells using biogenic hydrogen, then the amount of electricity generated from biogenic sources rises to about 3.5 TWh/yr. in 2050, which covers 4% of the total domestic electricity production. Biogenic heat maintains its share in the total heat supply (including district heating and on-site generation in industrial and building complexes) as of today. Biogenic CHPs contribute to balancing the electricity system, as discussed in more detail in section 5.4.

Biogas and biomethane become important energy carriers in the future energy system of Switzerland by 2050, in the *CLI* scenario. As shown in figure 4.4, about 54 PJ of biomass (primary energy) are used to produce about 27 PJ of biogas. Hydrothermal gasification of waste emerges after the mid-2030s and produces almost half of the total biogas from green waste by 2050, which corresponds to about 5.4 PJ. Wood gasification (with CCS) produces about 7.3 PJ of biogas in 2050, while biogas from manure amounts to about 9.4 PJ by that time. The rest of the 27 PJ of biogas are produced via fermentation, including anaerobic and aerobic digestion. Of the total 27 PJ produced biogas from all biogenic sources, about the half is upgraded to biomethane.

The uptake of biogenic gases occurs in all energy system sectors in the *CLI* scenario. In the long-distance public and freight road transport biogenic gases mainly occur until 2040, as gas-fuelled internal combustion engines are mostly transition technologies (see also section 3.4). The stationary end-use sectors alone consume about three-quarters of the total consumption of biogenic gases in 2050. In overall, biogenic gases account for more than the half in the total final energy consumption of gaseous fuels (excluding hydrogen) and about 20% in the consumption of gaseous fuels (excluding hydrogen) for electricity production by 2050 in the *CLI* scenario. In overall, biogenic gases help in avoiding about 1.5 Mt CO_2/yr. in 2050, which if emitted, would have required additional deployment of CO_2 removal options in the Swiss energy system to offset them.

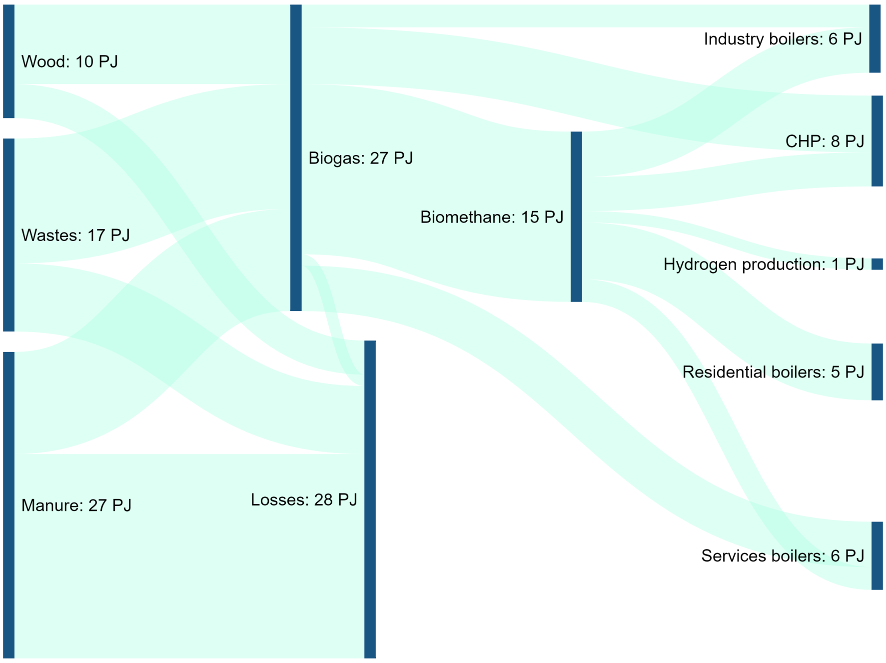


Figure 4.4: *Use of biogas, and upgraded biomethane, in the CLI scenario in 2050*

While biogenic gases mainly contribute to the decarbonisation of the end-use sectors, woody biomass, renewable municipal waste and other green waste are mainly used in the energy conversion sector and, in particular, in achieving negative emissions (figure 4.5). In waste incineration plants, about half of the renewable municipal waste is consumed in facilities equipped with CCS. Overall, one-third of the total renewable municipal and green waste is used in facilities equipped with CCS in 2050.

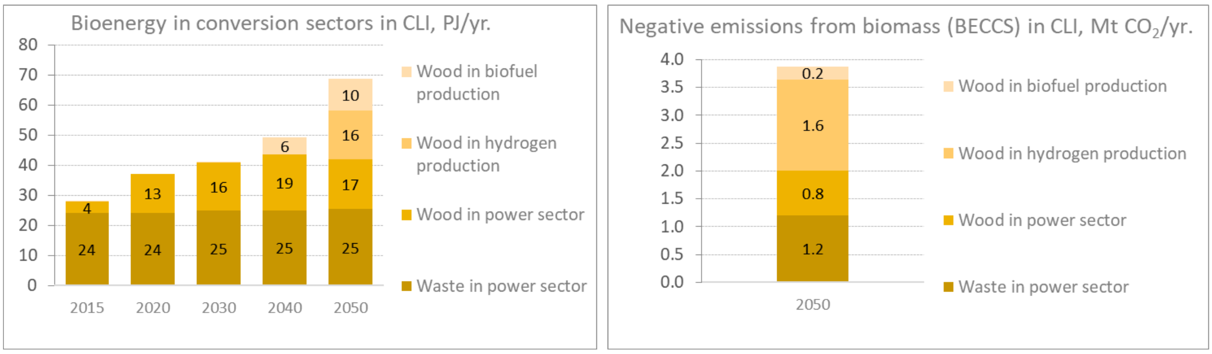


Figure 4.5: *Bioenergy use in the conversion sectors (left) and negative emissions using carbon capture and storage on energy conversion facilities using biomass (right) - the emissions from waste in power sector refer only to the renewable part of the waste (50% of the total waste in power plants with CCS)*

The use of wood in cogeneration and district heating increases over time in the *CLI* scenario (see section 6). However, in the last decade, there is increased competition for the resource from wood gasification in hydrogen and syngas production. Wood gasification is more cost-effective in producing hydrogen and syngas than electricity since there are no further efficiency losses from the generator turbine. The assumed technological developments facilitate its emergence for hydrogen. More than three-quarters of the use of wood in the energy conversion sectors is in combination with CCS to deliver negative emissions for achieving the net-zero emission target by 2050.

4.1.2 Transition enablers, opportunities and challenges

The demand for bioenergy almost doubles in 2050 from the levels of 2015. This requires to foster bioenergy projects and develop the infrastructure for bioenergy distribution (e.g. biogas) further. While wastes and forest residues are first options to supply the demand, which also have low environmental impacts and a mild effect on other economic activities, they are not sufficient to fully meet the incremental demand for bioenergy. Besides the full mobilisation of waste streams, increased use of manure for biogas production and exploitation of the remaining sustainable forest wood potential would be essential by 2050.

Today, manure is hardly used for energy production in Switzerland, and it is directly applied to fields, even though the use of manure for energy generation does not compete with its material use as fertiliser (Steubing et al., 2010). Although public acceptance for the use of manure in biogas plants is high (Soland et al., 2013), there are currently financial obstacles using such a low-energetic source. In (Burg et al., 2019) some strategies to promote the fermentation of manure have been identified that require broad social and political support, such as co-fermentation with a higher-energetic source (e.g. organic wastes), and implementation of financial incentives (e.g. subsidies, feed-in tariffs and CO_2 certificates) at least in short- to near-term, until the uptake of technology increases. The minimisation of collection loses and improving the logistics in organising the manure collection are also important technical constraints, because the Swiss farms are relatively small. However, most of the farms are closed together, which could enable the collection of the manure from multiple neighbouring farms for use in a single facility. Such an option could facilitate scaling effects and harvest the environmental benefits of manure (Steubing et al., 2010).

The sustainable intensification of the exploitation of forest biomass is constrained by the net annual increment of forest and ecological restrictions (Thees et al., 2020). According to (Thees et al., 2020), a balanced and moderate reduction of the forest wood stock has the advantage that increases its mobilisation for energetic uses in the short term without risking the potential in the long term. In contrast, intense harvesting risks future wood fuel supplies. Additional factors influencing the resource availability include conflicts with the production of wood material for other sectors and with other eco-services provided by the forest such as climate regulation, pollution control, soil protection, biodiversity protection, water regulation, recreational services, etc. The afforestation and reforestation can expand the forest area and, hence, develop the synergies between the different uses of forests (Doelman et al., 2020). However, both afforestation and reforestation affect the land use, in particular for agriculture. In addition, afforestation is a slow process, and it can take several decades until the benefits in biomass provision (and CO_2 removal) materialise (EC, 2018).

The analysis did not consider dedicated energy crops, which are characterised by faster-growing rates and higher productivity potential than forest-based biomass production, due to concerns related to food security. The Swiss policy so far does not clearly support their development (Steubing et al., 2010). However, energy crops can maintain, to some extent, economically viable yields on marginal lands and preserve the soil content in organic carbon compared to arable land (Hoefnagels et al., 2017). Their exploitation can be facilitated, and offer farmers new financial perspectives, if efficiency improvements in their production and efficient use of land accompanied by biodiversity and environmental sustainability in land management techniques are realised and implemented (EC, 2018).

4.2 Imported biofuels and e-fuels

4.2.1 Import needs and trajectories

Imported gaseous biofuels and synthetic e-fuels become significantly important in the transition towards net-zero emissions in 2050. The transport sector is in the highest need for zero-carbon liquid energy carriers to decarbonise the long-distance public and freight transport. Also, gaseous imported zero-carbon energy carriers are used in stationary sectors. In the analysis, we do not distinguish between imported biofuels of biogenic origin and e-fuels produced from Power-to-Gas or Power-to-Liquids pathways, as this would have required the use of a global energy markets modelling framework. Moreover, since the penetration of e-fuels is cost-efficient when a climate policy is implemented worldwide, as their production is based on carbon capture, it can be argued that e-fuels have more chances to occur in *CLI* rather than in *BAU* and *EPOL* scenarios.

The imported biofuels and e-fuels (hereafter, combined, zero-carbon fuels) penetrate in all the three scenarios (figure 4.6), but their drivers differ across the scenarios. For example, in *BAU*, the current trends and mandates in the use of bioliquids and biogases in the energy mix sustain a relatively low level of imported biogenic zero-carbon fuels. In *EPOL*, the increased imports of zero-carbon energy carriers are also attributable to vehicle emission standards. In *CLI*, the climate policy to achieve net-zero emissions in 2050 enables a further increase in the imported zero-carbon fuels.

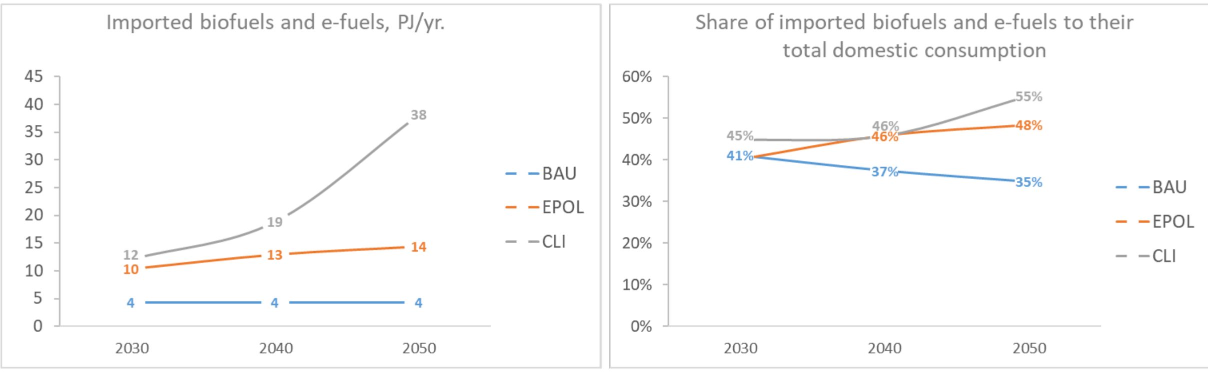


Figure 4.6: *Imported biofuels (liquids or gases) and e-fuels (left) and their share in the total domestic consumption of biofuels and e-fuels (right)*

4.2.2 Transition enablers, opportunities and challenges

The main challenge of the imported biofuels and e-fuels in the net-zero scenario concerns their availability. Especially in the context of a global effort to achieve the Paris Agreement targets, it can be expected that there would be increased competition for accessing these resources worldwide.

Regarding advanced biofuels, there are multiple challenges to overcome related to an array of infrastructure, environmental, social and political issues. IRENA identifies the following barriers in the deployment of biofuels worldwide, which hold their wide penetration (IRENA, 2019): public perception, feedstock availability and price, level of blending mandates, level of subsidies, technology risks and process reliability, availability and cost of financing, conversion efficiencies and CAPEX, and regulation stability. The advanced biofuel industry is currently small and fragmented, and its further development needs clear investment signals. The transport sector could trigger investments in their supply, but, as also shown in the current analysis, the decarbonisation of mobility calls for several fuel alternatives simultaneously rather resorting to one encompassing solution.

E-fuels are carbon neutral only when renewable electricity is used, and the source of carbon comes from biomass or direct air capture (Sacchi et al., 2021, Liu et al., 2020). E-fuels are the same as natural gas or oil in their molecular structure, and they can be distributed and use by existing infrastructure. However, their production requires large amounts of electricity. Thus, there is a trade-off between the versatility in using e-fuels with their right scale in the consumption: a small uptake would hamper technology progress in their production, while a large roll-out would increase electricity needs (and carbon capture requirements) on the supply side (EC, 2018). Also, there is a large uncertainty around the production cost of e-fuels and the pace of development of all components needed to produce them. In order to harvest possible returns to scale in their production, an approach is to concentrate the facilities for e-fuels on specific sites with access to significant electricity and gas hubs [1].

4.3 Hydrogen

4.3.1 Consumption of hydrogen

In 2018, the hydrogen consumption in Switzerland amounted to 0.11 PJ (or 431 GWh), of which 85% is consumed in refineries in integrated processes that do not generate external demand (Lehner et al., 2018). By excluding refineries, hydrogen demand in Switzerland today is less than 0.02 PJ (65 GWh).

By 2030, hydrogen use for the supply of low, medium and high-temperature heat emerges in industry in both *EPOL* and *CLI* scenarios (figure 4.7). In the *EPOL* scenario the electricity consumption targets in the end-use, in combination with the improvement in the performance of the fuel cell technology, drives the uptake of hydrogen in industry. In the *CLI* scenario, deployment of hydrogen is also facilitated by the increasing carbon prices and the reinforcement of the emission trading scheme that provides incentives for industry to shift towards low-carbon energy carriers to reduce its emissions. Because of the technical challenges related to the direct burning of hydrogen (high combustion velocity, low radiation heat transfer, corrosion and brittleness in boilers), the major application in hydrogen for process heat is in fuel cells. Molten carbonate fuel cells and solid oxide fuel cells can supply heat that reaches a temperature of 1000^{o}C (Bauer et al., 2017).

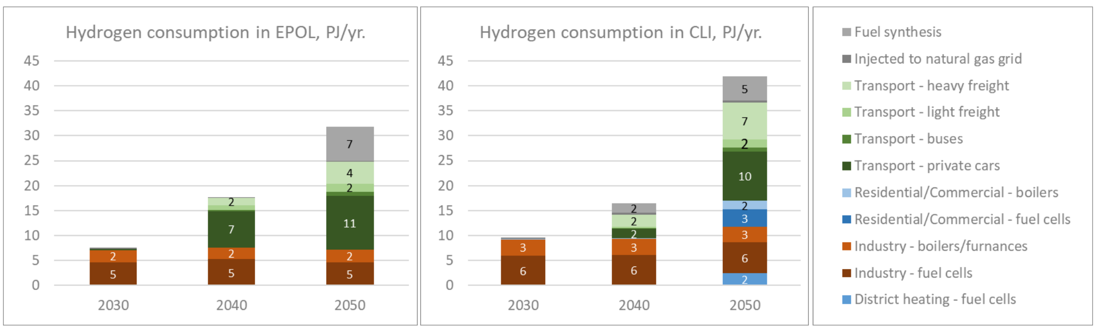


Figure 4.7: *Hydrogen consumption in the different end-uses in the EPOL and CLI scenarios*

While industry can be a first mover in the use of hydrogen as an energy carrier in the Swiss energy system, the scaling up of the domestic consumption is primarily based on the transport sector in both

[1] See for example https://www.siemens-energy.com/global/en/news/magazine/2020/universal-e-fuel-hubs.html

EPOL and *CLI* scenarios. If the cost of fuel cell stacks will be reduced to the levels envisaged by the manufacturing industry, then the fuel cell vehicles can become competitive to the battery-electric ones in the private transport, and to the internal combustion and hybrid engines in the freight transport. In the *EPOL* scenario, the use of hydrogen in the mobility sector is mainly driven by the overall energy and electricity consumption targets in the end-use sectors, and to a lesser extent by the vehicle emissions standards. This is because, in *EPOL*, hydrogen supports energy efficiency improvements in the demand sectors and limits their electricity consumption, contributing in this way to the achievement of the overall efficiency objectives of the scenario.

In *CLI*, however, it is the enforcement of stringent vehicle emissions targets in the second half of the projection period together with the overarching objective of achieving net-zero emissions by 2050 that drives the uptake of hydrogen in almost all transport modes, and, in particular, in those that are hard to electrify via battery-electric vehicles, such as the heavy-freight and long-distance road transport. These outcomes suggest that stringent climate policy is an important enabler of hydrogen penetration in the Swiss energy system. Hydrogen also emerges when electrification of the demand is restricted or not possible, in order to reach ambitious efficiency targets.

District heating from stationary fuel cells also emerges beyond 2040 in the *CLI* scenario. The concept builds on micro-grids that can provide electricity and heat to building blocks and communities[2]. Fuel cells can be scaled-up to serve large residential, office and industrial building complexes, benefitting from the advantage of high electrical efficiencies. Their application in district heating has benefits compared to the application in single houses or buildings where the penetration of fuel cell CHPs is hindered by their high upfront costs and complexity of their integration compared to alternative heating options.

On top of the direct use of hydrogen in industrial, commercial, district heating and mobile applications, hydrogen is also used to produce synthetic methane and synthetic oil products. As shown in figure 4.7 in both *EPOL* and *CLI* scenarios, hydrogen is used for the production of synthetic gas (methanation) and synthetic liquids (Fischer-Tropsch), which are then consumed in heating sectors, road transport and domestic aviation. The source of carbon is CO_2 that is captured from the production of electricity, hydrogen, industrial processes, and direct air capture. In the *EPOL* scenario, the production of synthetic fuels emerges in 2050, while in *CLI*, it starts a decade earlier. In both scenarios, a major enabler of their production is the provision of flexibility to the electricity system and the decarbonisation of the other end-use sectors using the existing installations/applications. While in *EPOL* liquids have the lion's share in the production of synthetic fuels (mainly gasoline), in *CLI* hydrogen methanation emerges as well at substantial shares, also by using carbon from biogenic sources. This difference is mainly attributable to the end-use sector developments, as in *CLI* the transport sector shifts away from fossil fuels while synthetic gases are still needed in the stationary sectors. It should be noted that the analysis excludes the possibility to use synthetic fuels in international aviation, which is a sector with potential for scaling-up their consumption (McKinsey, 2020). The domestic production of synthetic fuels faces strong competition from imported zero-carbon e-fuels (see also section 4.2).

Thus, hydrogen in the end-use sectors penetrates both in direct applications (e.g. in hydrogen-fuelled boilers and vehicles), as well as indirectly via electricity and heat produced by fuel cells and synthetic

[2]See for example the FC-District Project https://cordis.europa.eu/project/id/260105/reporting,theLEMENEProjecthttp://www.lempaalanenergia.fi/content/en/1/20126/LEMENE.htmlandtheELECTROUprojecthttps://www.fch.europa.eu/project/mw-fuel-cell-micro-grid-and-district-heating-king\T1\textquoterights-cross

fuels. In the *CLI* scenario, the direct consumption of hydrogen accounts for about 5% of the total final energy consumption in 2050. When also the domestically produced e-fuels from hydrogen are accounted for, then the (indirect) share of hydrogen in final energy consumption increases to 8%. And, when the electricity and heat produced from hydrogen fuel cells are also accounted for, then the (indirect) share of hydrogen in total final energy consumption increases to more than 10%. The relatively small share of hydrogen should be seen in the context of the higher efficiency that fuel cells achieve in meeting the electricity, heat and mobility demands compared to boilers and conventional cars.

4.3.2 Production of hydrogen

In the *EPOL* scenario, the hydrogen demand is mostly met by SMR/ATR until 2040, which is the incumbent technology today. By 2050, electrolysis also penetrates at a large scale, driven by the increased uptake of renewables and improvement in its performance (cost and efficiency). In the *CLI* scenario, hydrogen appears in the Swiss energy system by the time when carbon prices are high, and large emissions reductions are needed to achieve carbon neutrality by 2050. Hence, fossil-based technologies to produce hydrogen without CCS can only be considered as bridging options, until CCS matures or the costs of electrolysis declines.

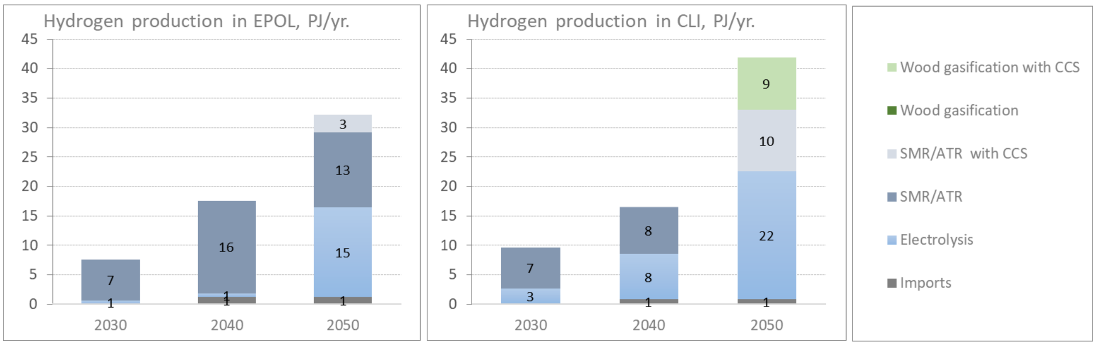


Figure 4.8: *Hydrogen production by technology in the EPOL and CLI scenarios*

As shown in figure 4.8, in 2050, when deep reductions in CO_2 emissions are needed, producing fossil-based hydrogen without CCS is not an economically viable option. SMR/ATR loses shares in favour of electrolysis and wood gasification with CCS. Any SMR/ATR plants that remain in operation need to be equipped with CCS in the last decade of the projection horizon, and if possible, to use biogenic gas as a feedstock. However, biomethane is limited, and there is strong competition for the resource in other sectors where gas cannot be easily replaced (e.g. industrial processes). In the current analysis, less than 10% of the hydrogen produced with SMR/ATR in 2050 is based on biomethane. This also implies that when net-zero emissions in 2050 are to be achieved, large-scale penetration of SMR/ATR relies on the future availability of CCS. Otherwise, stranded assets can be generated in the long-run.

Electrolysis has a dual role in the Swiss energy system. It represents a scalable low-carbon option for hydrogen production and at the same time helps in the daily and seasonal balance of the electricity system. It can convert excess renewable electricity to hydrogen, which then can be stored at daily, weekly and seasonal timescales (see also next section). In both *EPOL* and *CLI* scenarios, the main source of electricity in electrolysers is hydropower (mainly run-of-river), as the bulk of the electricity produced in solar photovoltaics is mainly consumed and balanced locally. Electricity from solar is used in electrolysis only when other demand-side and flexibility options are not available or cannot be deployed on a larger scale. Electrolysis using electricity from distributed solar photovoltaics mainly occurs in summer, and especially in summer weekends, see also (Panos et al., 2019a). Since electrolysers use electricity from the medium to upper voltage levels, they also face the overhead from grid connection costs and water.

One of the most promising options for producing hydrogen when carbon prices are high is through biomass gasification with CCS. However, the technology is currently rather immature, which is a barrier of its early penetration. In the long-run, i.e. after 2040, when it is assumed that the technology has reached commercialisation level, it represents a cost-effective decarbonisation option that helps in offsetting remaining emissions in other sectors. A major barrier that hinders its scalability is the availability of wood and the competition for the resource from other sectors in the energy system.

4.3.3 Power-to-X

The transformation of the Swiss electricity sector towards increased shares of solar PV in Switzerland, accentuates the need for balancing the system at different timescales: daily, weekly and seasonal. In this regard, hydrogen produced from renewable electricity can increase the energy system's flexibility to integrate high shares of variable renewable energy. As shown in figure 4.9, about a quarter of the produced hydrogen from electricity in the *CLI* scenario is stored and seasonally shifted from summer to winter in 2050, in order to balance the system.

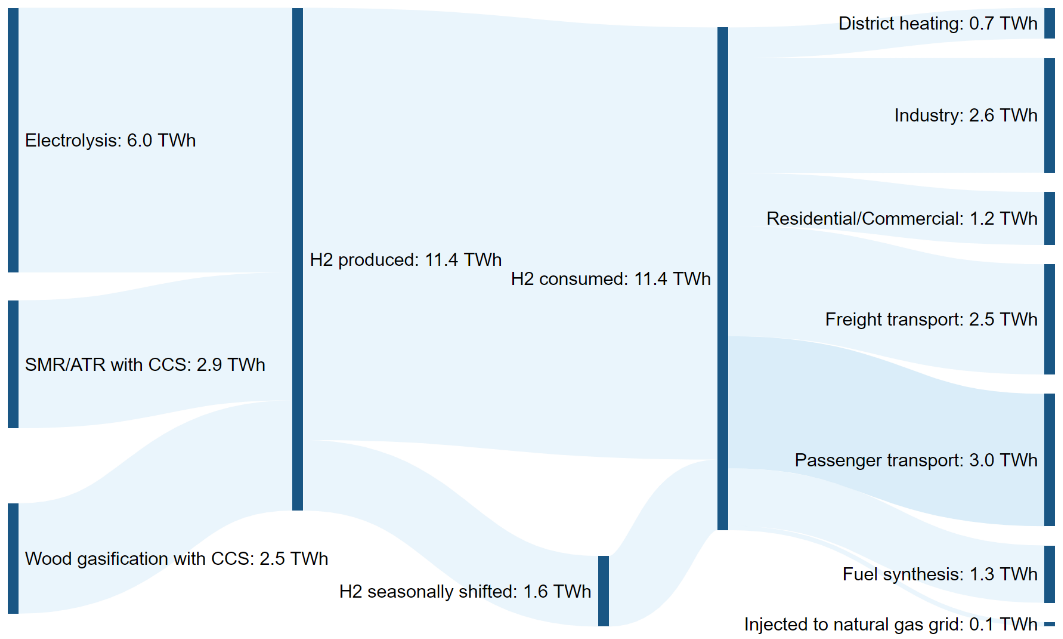


Figure 4.9: *Production and demand for hydrogen and its role in the seasonal balancing and sector coupling in the Swiss energy system in the CLI scenario in 2050*

Figure 4.10 shows the cumulative investments, both in physical and monetary terms, to the P2X and hydrogen-related technologies from 2030 to 2050. The cumulative capital outlays to electrolysis account about half of the investment expenditures in hydrogen production technologies. The cumulative investment expenditures for hydrogen distribution and storage are more than twice those for hydrogen production. When also including the investments for the distribution and equipment in hydrogen fuel stations, then the total investment in hydrogen distribution, storage and vehicle fuelling infrastructure is more than 4.5 times higher than the investment in hydrogen production.

In the total CAPEX for hydrogen distribution and storage infrastructure (also by including fuel service stations), pipelines have the highest share with more than 60%. Fuel service stations, by accounting only for the stations' equipment and not for pipelines and trucks delivering hydrogen to them, account for 25%. Another 10% is directed to storage of hydrogen and the rest to hydrogen distribution with trucks. The delivery of hydrogen in the mobility sectors dominates the transmission, distribution and storage costs as it accounts for more than 90% of the total capital outlays in hydrogen distribution infrastructure, indicating the importance of the sector for the penetration of hydrogen.

The lion's share in the expenditures in hydrogen technologies is on the demand side, which is almost two-thirds of the total amount spent between 2030 and 2050 in hydrogen-related technologies. Among the demand technologies, the fuel cell stacks in vehicles alone absorb more than 90% of the total investment expenditures in hydrogen demand technologies. The rest 10% is mainly allocated to stationary fuel cells.

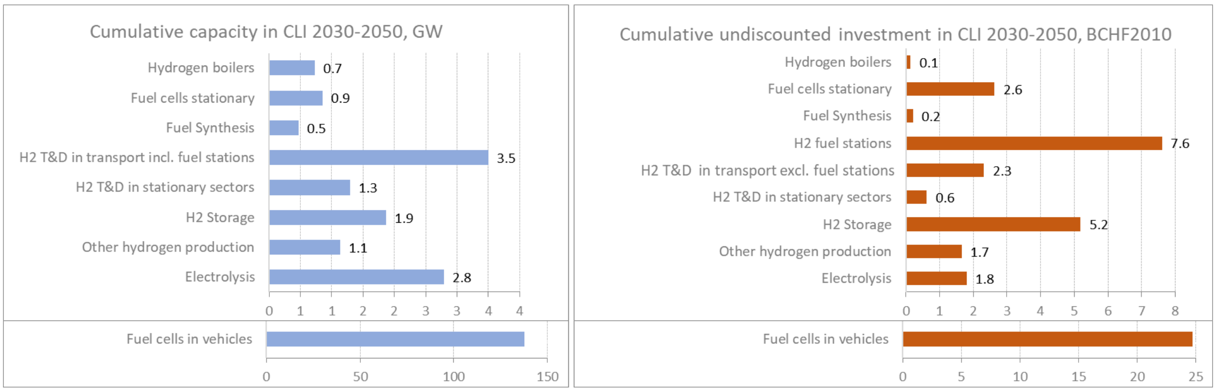


Figure 4.10: *Cumulative installed capacity (left) and cumulative investments in H_2-related technologies (right). The capacity referrers to GW_{H_2} for production, storage and distribution technologies, to GW_{el} for stationary and mobile fuel cells and GW_{th} for fuel synthesis. The investments in mobile fuel cells refer to the total car cost minus the glider cost*

4.3.4 Transition enablers, opportunities and challenges

4.3.4.1 Hydrogen supply and demand

The renewable and low carbon-based hydrogen is an energy carrier of growing importance in a climate-neutral and low air pollution Swiss economy in 2050. A strong climate policy accelerates its deployment. However, the future success and timing of the hydrogen economy are highly dependent on technological developments and targeted measures. Industry can be the first mover for hydrogen applications until 2030, but transport scales up hydrogen uptake in the post-2030 period. The automotive applications constitute a key segment for the future of fuel cells, lead improvements that can spill over to other applications, and carry forward infrastructure development. Hydrogen applications in buildings face high upfront costs and strong competition with existing infrastructures. District heating microgrids based on fuel cell CHP can be an option to provide hydrogen-based heat in residential and industrial complexes.

In a long-term perspective hydrogen supply progressively shifts from natural gas-based steam methane reforming (SMR/ATR), which is deployed first, to renewable hydrogen (electrolysis, wood gasification and biogenic SMR/ATR with CO_2 capture). SMR/ATR units need to be equipped with CO_2 capture and storage by 2050 and natural gas as feedstock needs to be partly replaced by biomethane, especially when deep negative emissions are needed. For the scaling-up of the hydrogen production from solid biomass, there are challenges related to biomass availability and the competition for this resource with other sectors in the energy system seeking for carbon-neutral energy sources.

The mid-term horizon until 2030/40 is crucial for the wider deployment of hydrogen in the long term. As investment cycles in the clean energy sector run for about 25 years, and the time needed for new energy technologies to penetrate existing markets is long, boosting demand and supply of hydrogen requires various forms of support to help stimulating commercial demand for cleaner hydrogen.

During the transition phase of the hydrogen infrastructure development, policy support should not lead to stranded assets. To foster investors' innovation and confidence, policy needs to provide stable long-term signals (such as rigid climate goals), creating demand for hydrogen while mitigating the investment risks. The creation of hydrogen demand can be facilitated by stringent emission and efficiency standards for vehicles and buildings or market-based mechanisms such as fossil fuel taxation. Industrial clusters may offer good opportunities for low-carbon hydrogen deployment and could be stimulated by a reinforcement of the emission trading scheme and carbon intensity reduction goals.

4.3.4.2 Power-to-X pathways

Power-to-X technologies become an important building element in the transition of the energy system in future, but it is not yet economically viable to invest in them at a wide scale. There is a need for a clear regulatory framework in terms of objectives and criteria for Power-to-X projects to be eligible for appropriate funding and incentives to bridge the economic gap between these technologies' actual costs and current market value of the services provided (Kober et al., 2019). For example, grid charges for the Power-to-X technologies could reflect their value to the electricity system by avoiding investment in power grids (GIE, 2019). Besides, more R&D funding should target the development of Power-to-X technologies to achieve competitive production costs (IEA, 2020). A further reduction of the production costs can be achieved by placing Power-to-X technologies near low-cost electricity generation sites, gas hubs, CO_2 sources and consumption centres for Power-to-X products.

The analysis with STEM indicates that important for the successful market integration of Power-to-X pathways is the ability to combine revenues from different markets. These include not only sales of heat, hydrogen and synthetic fuels, but also revenues from services in ancillary markets and possible trade of CO_2 certificates (Kober et al., 2019). The implementation of stringent climate change mitigation policies and the exploitation of new renewable energy can increase the contribution of Power-to-X technologies to a cost-efficient, low-carbon and reliable energy supply in Switzerland.

As pointed by (GIE, 2019, Van Nuffel et al., 2018), the realisation of sector coupling via Power-to-X would require coordination of electricity, gas and hydrogen grids. So far, the regulatory and market framework for gas and electricity does not consider communication schemes between operators of distribution networks for different energy carriers. In the next decades, this has to be improved to better balance supply and demand of energy. To this end, the planning activities for strengthening networks need to consider interdependency between the power and gas sectors, and, in the long-run, also between the hydrogen sector. There is a wide literature identifying the main barriers hindering Power-to-X technology deployment (see for example (GIE, 2019, Kober et al., 2019, Van Nuffel et al., 2018)). These can be grouped to the following categories: a) market design barriers that do not recognise the value of the products of Power-to-X to the energy system in this new role under sector coupling; b) regulatory barriers that include the conditions of usage and access of networks and infrastructures as well fiscal and taxation issues; c) technical barriers that include the definition of technical standards on a number of operational issues among Switzerland and its neighbouring countries; d) governance barriers that impede the planning and collaboration across different parts of the energy sector that need to work together in sector coupling.

Possible solutions to overcome barriers in the market design include, among others (GIE, 2019): a) fostering liquidity of electricity, gas and hydrogen markets in the short term by re-examining the balancing timeframes; b) internalising externalities, including carbon prices, to provide long-term signals for Power-to-X products; c) introducing market mechanisms, such as renewable certificates of origin also for Power-to-X products, to mitigate high upfront costs and increase investment's viability.

Regulatory barriers can be lifted by introducing new network codes for sector coupling that specify technical and operational details (Van Nuffel et al., 2018). For example, Italy allows the gas TSOs to have more short-term network capacity and to include more short-term products (GIE, 2019). Network charges for storage and other activities related to sector coupling via Power-to-X can be differentiated, and infrastructure access tariffs can be redesigned to account for the provision of flexibility to the energy system at different time- and spatial scales, and also considering the avoidance of grid congestion and additional investment. Such tariffs and network charges could incentivise the use of Power-to-X system at least in short- to medium-term until the technology matures (Kober et al., 2019). If renewable energy is not financially competitive it will be difficult for sector coupling to progress without regulatory intervention.

Technical barriers call for additional research in understanding and capabilities of existing gas networks (GIE, 2019). Examples include the need to define the most suitable blending limits of hydrogen into the natural gas grid by accounting for the hydrogen tolerance of end-user appliances, or to define the extent of a possible re-purposing of the existing gas network. In addition, there is a lack of cross-qualified human resources. For instance, in Germany, chief engineers in DSOs already need to have a dual qualification both in gas and electricity networks (GIE, 2019).

Taxation could also be more flexible. For instance, it could classify storage as a separate element in the energy system, distinct from end-users. In Denmark, for example, storage is not subject to tax as it is considered an energy supply process (GIE, 2019). Harmonisation of national taxation schemes related to Power-to-X products and ancillary markets services are also required across neighbouring countries (GIE, 2019), if trade of these products and services is involved, to avoid double taxation or subsidy (e.g. if the country of origin subsidises supply and the destination country end-use).

Governance related approaches include the coordination in the infrastructure planning for both electricity and gas networks to avoid the creation of adverse incentives and narrow sectoral approaches. Or, investment approval of Power-to-X projects could be subject to a cost-benefit analysis comparing options across sectors as opposed to options within sectors. Close work between local electricity and gas DSOs would create value and allow them to operate in both sectors (GIE, 2019).

The energy transition to net-zero challenges the role of natural gas in the Swiss energy system. Decarbonised synthetic gaseous fuels (e-gases, biomethane and hydrogen), provide clean energy to industry and buildings without loss of utility. The deployment of Power-to-X can contribute to prolonging the life and use of existing natural gas infrastructure to distribute synthetic gases. The interconnection and integration of energy supply and demand sectors, and their joint adaptation to energy production and consumption patterns, are the basis for the best possible use of available resources and avoidance of stranded assets.

Chapter 5

Electricity production, consumption and storage

Electrification becomes an increasingly important element in the future Swiss energy system. Even in the *BAU* scenario, the electricity share in final energy consumption increases, reflecting the current trends. The implementation of efficiency measures in *EPOL* does not hinder the increased electrification of the demand, while in *CLI* under stringent climate policy, the higher electrification of the demand contributes to decarbonising the end-uses. While electricity becomes a dominant energy carrier in the future, the electricity generation structure differs from today.

5.1 Demand

Electricity demand increases significantly from today in all scenarios compared to 2015 levels (figure 5.1), with transport seeing the most spectacular development of electricity use.

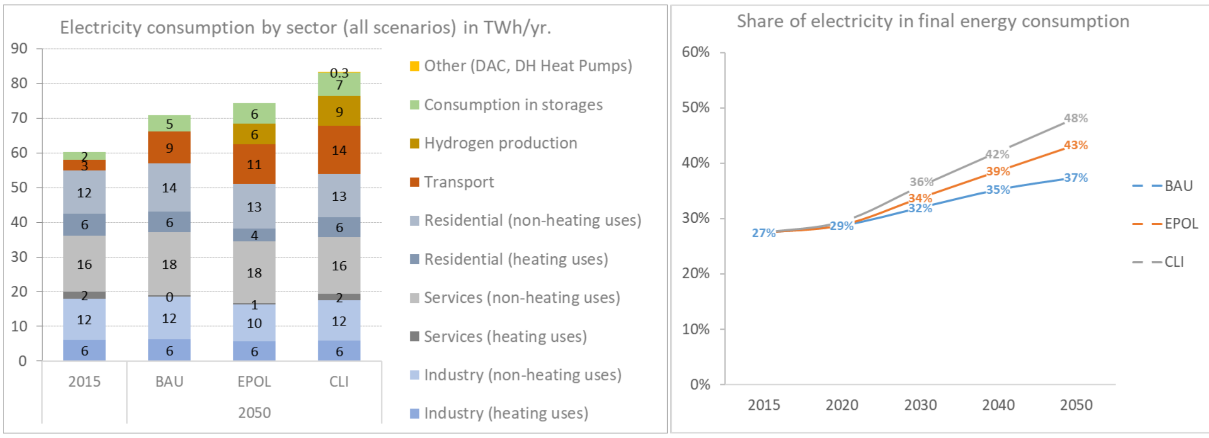


Figure 5.1: *Overview of the electricity consumption, excluding T&D losses, (left) and electrification of the final energy consumption, including environmental heat and by excluding international aviation (right)*

In *EPOL* and *CLI* scenarios, new sectors for electricity consumption emerge, such as the production of hydrogen and synthetic fuels, as well as the consumption of electricity in Direct Air Capture and large scale heat pumps for district heating (that use waste water as a heat source). At the same time, in *EPOL* and *CLI* scenarios, there is a substantial increase in the consumption in storages as a result of the large deployment of variable renewable energy. In contrast, industry, services and residential sectors hardly increase their electricity consumption in 2050 from 2015 levels, driven by the strong deployment of building renovation and other energy conservation measures, as well as technology switch to more efficient electrical equipment. Despite the saturation of electricity consumption in the stationary end-uses of electricity, the electrification of the final energy consumption increases from 2020 to 2050 driven by the developments in the transport sector.

From 2020 to 2040, electricity consumption shows a moderate increase in the three core scenarios, and in the range of the observed trends, as efficiency gains offset the growth of electricity in the stationary sectors. During this period, the increase in electricity consumption is mainly driven through the growing market share of electric vehicles in the passenger mobility sectors. In the *CLI* scenario, and to a smaller extent in *EPOL* too, the effect of the electrification of the transport sector becomes more prominent during the decade between 2040 and 2050, by when the use of electricity for decarbonising the transport sector further increases and drives the overall electrification of the demand.

In *CLI*, not only the battery and plugin electric vehicles are the main drivers for the increase in electricity consumption in Switzerland by 2050, but also the fuel cell vehicles to the extent that the hydrogen they consume is produced from electrolysis. If accounting also for the electricity needed to produce the hydrogen consumed in the transport sector, then transport is responsible for almost three-quarters in the incremental electricity consumption between 2015 and 2050. The significant share of the transport sector in the additional electricity supply required in the next years, also suggests that the deployment of efficiency measures in the stationary sectors would be necessary for a more rational use of electricity. The coordination of these efficiency measures across the stationary end-use sectors is essential to avoid a further increase in electricity production needs in Switzerland, in order to achieve the net-zero ambition.

5.2 Supply

Following the developments in consumption, the electricity supply increases in all the three scenarios throughout the projection period (figure 5.2).

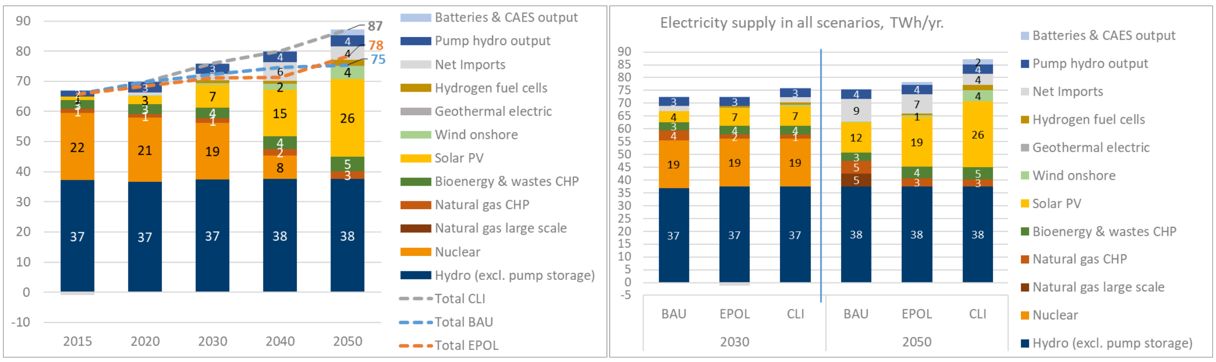


Figure 5.2: *Trajectory of the electricity supply and its mix in the CLI scenario (left), and comparison of the electricity production mix in 2050 across the three core scenarios (right)*

The largest growth in electricity supply is observed in the *CLI* scenario, whereby not accounting for output from pump hydro and other storages the total electricity supply is around 80 TWh in 2050. The electricity supply in *CLI* starts to follow an exponential increase even from 2030, as the electrification of mobility accelerates.

The *EPOL* scenario displays a trajectory of a modest increase in electricity supply until the mid-2030s, driven by the efficiency and electricity consumption targets indicated in the Swiss Energy Strategy 2050. However, the penetration of electrolysis in hydrogen production (also for the provision of hydrogen in the transport sector) that occurs after 2040 in *EPOL* induces a strong growth in electricity needs in the last decade of the projection horizon.

In the *BAU* scenario, the total electricity supply increases to higher levels than in *EPOL* until 2040. However, it plateaus after the nuclear phase-out, as electrification of the demand, and particularly the electrification of transport, is not accelerating, while in stationary sectors there is a switch to efficient electric equipment. Hence, in the last decade of the projection period, the electricity generation in the *BAU* scenario remains the lowest among the three core scenarios.

Regarding the electricity generation mix, the additional electricity demand is mostly satisfied by production using Swiss domestic resources, primarily solar, bioenergy and wind in all scenarios. The nuclear power plants are assumed to have a lifetime of 60 years, except for Mühleberg. Hence, the last nuclear reactor is decommissioned by the mid-2040s. In this context, non-hydro renewable electricity sees its share in the electricity generation substantially increasing in 2050 in all scenarios, reaching 45% in *CLI* and 37% in *EPOL*, compared to the 6% in 2015. Solar PV represents the lion's share in non-hydro renewable electricity supply and experiences an accelerated deployment in all scenarios over the next decades. Wind turbines mainly penetrate the *CLI* scenario as the ambition to achieve net-zero emissions in Switzerland by 2050 would require the exploitation of almost all available renewable energy sources.

The electricity generation from bioenergy, including biogas, biomethane and wood, as well as from wastes, remains at the levels of 2015 in the *BAU* scenario and sees a slight expansion in *EPOL* and *CLI* scenarios. Wastes remain the main source of electricity generation from biogenic sources. Wood in cogeneration increases in all scenarios from the levels of today. In 2050, it doubles in *BAU* and becomes five times higher in *EPOL* and *CLI* from 2015. Still, its contribution to electricity supply is less than 2 TWh in 2050. In *CLI*, there is competition for wood across several sectors, including district heating, stationary sectors (also via pellets), and hydrogen production, besides the electricity sector.

Electricity from deep geothermal remains a challenge because of its limited social acceptance, high production costs compared to the rest of the renewable options, and especially when compared to solar PV (Bauer et al., 2017), as well as low efficiency. In the *CLI* scenario, deep geothermal applications for electricity production are unlikely to occur by 2050. However, the use of deep geothermal energy for district heating emerges in this scenario from 2040 (see also section 6.1).

Hydropower remains the main renewable resource in Switzerland. Despite its limited expansion, reflecting stricter water management regulations and taxes, as well as climate change impacts on the availability of the resource, the share of hydropower in the future electricity supply mix constantly remains above 50% throughout the projection period in all scenarios.

Electricity imports also fill the gap in the supply after the nuclear phase-out in all scenarios and more pronounced in *BAU*, where the deployment of renewable energy remains at lower levels compared to *EPOL* and *CLI*. Large scale gas generation only occurs in *BAU*, but to a relatively limited extent of one to two power plants. In the *EPOL* and *CLI* scenarios, there is no large scale gas-based generation, as the implemented renewable and climate policies do not favour a cost-effective deployment of large gas turbines.

The overall net installed electricity capacities substantially grow from 2015 levels in all the three scenarios because of the large scale penetration of solar PV (figure 5.3). Such a massive growth will represent an investment challenge, but also an opportunity for the rejuvenation of the power generation infrastructure and the development of economic activity and supply chains in Switzerland. The deployment of renewables is, therefore, even more visible in the net installed capacities. The installed solar PV power increases by 12 times in the *BAU* scenario and more than 20 times in *EPOL* and *CLI* scenarios from 2015 to 2050. In the *CLI* scenario, the massive deployment of solar power suggests a doubling of the installed capacity every ten years, which represents a formidable challenge to overcome. One has to keep in mind that the typical lifetime of a PV plant is much shorter than the ones of large hydropower plants or nuclear power plants which implies that regular re-investments are needed to maintain such high levels of installed PV capacities. By 2050, in the *CLI* scenario, there is also a substantial deployment of electricity storage and wind turbines.

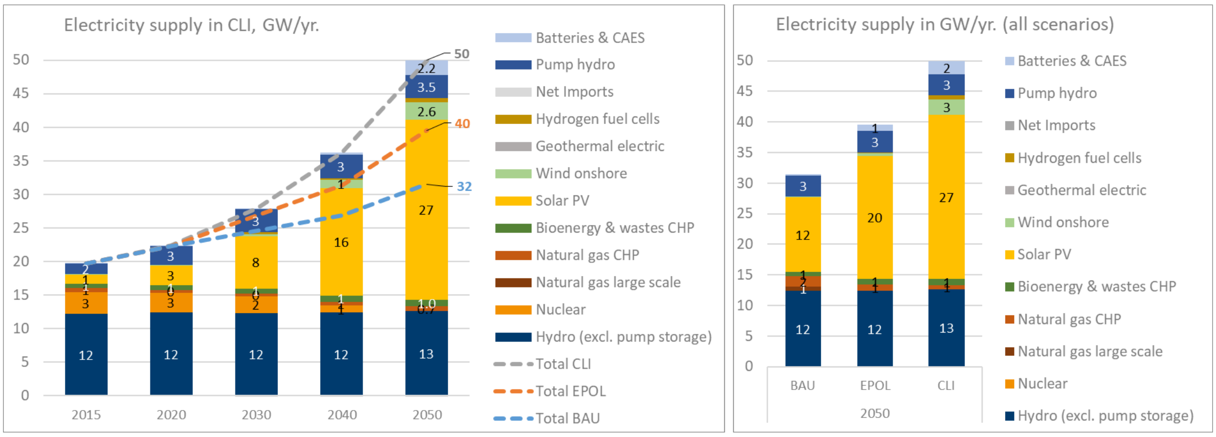


Figure 5.3: *Trajectory of the electricity supply capacities, excluding the cross-border inter-connectors, in the CLI scenario (left), and comparison in 2050 across the three core scenarios (right)*

As a result of the changes described above, the electricity generation sector in Switzerland retains its low carbon footprint in both *EPOL* and *CLI* scenarios. As described in section 7.1.5, the sector also delivers negative emissions in the *CLI* scenario, which results in a negative carbon intensity of the electricity production by 2050. Only in the *BAU* scenario, the carbon footprint of the electricity generation sector increases in 2050 from today, because of the penetration of natural gas-based generation to fill the supply gap after the phase-out of nuclear power.

Cogeneration

Cogeneration increases its share in the electricity supply in the future Swiss energy system in all scenarios, particularly in *CLI*. Besides the increased electricity needs in the end-use sectors (and mainly in industry) a second driver for cogeneration is the expansion of district heating (see section 6). The electricity production from CHP plants accelerates in the next decade and doubles in 2030 compared to 2015. In the post-2030 period, there is a deceleration in the growth of the electricity production from CHP plants or even a saturation (in the *BAU* scenario). The three core scenarios show different trends concerning the sectors in which this expansion takes place, and in the fuel mix (figure 5.4).

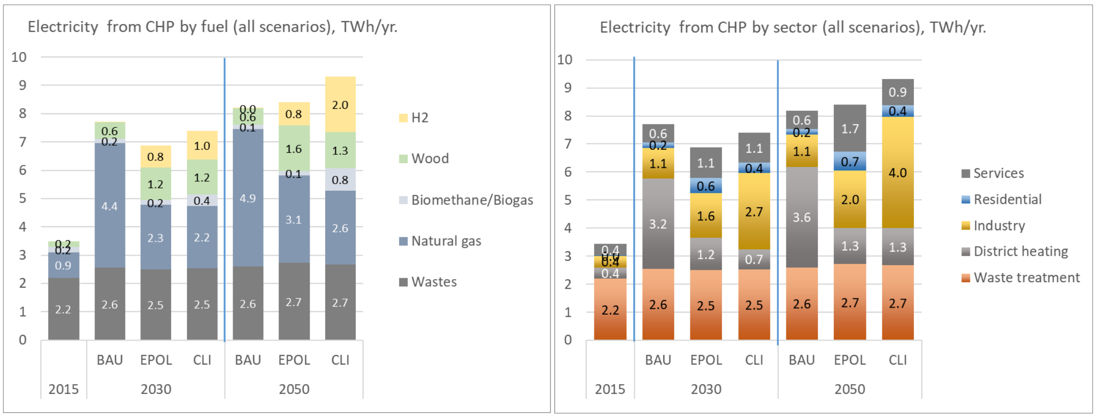


Figure 5.4: *Electricity generation from CHP plants by fuel and sector. For wastes, the figure also includes the ones characterised as "electric-only" in the statistics from the Swiss Federal Office for Energy (Kaufmann and Eicher+pauli, 2019)*

In the *EPOL* scenario, and more pronounced in *CLI*, industry drives the penetration of CHP plants in the electricity supply in the next decades. This is attributable to the efficiency gains that can be achieved by cogeneration of electricity and heat. In contrast, in the *BAU* scenario, the expansion of the district heating is the main enabler for the increased penetration of CHP together with the need to partially fill the gap in the electricity supply after the nuclear phase-out, given that new renewables, solar PV and wind, contribute to a much lesser extent in this scenario compared to *EPOL* and *CLI*. In contrast, in *EPOL* and *CLI* scenarios, the penetration of CHP substantially increases after 2030, also because of the uptake of cogeneration in residential and services sectors. Thus, the saturation in the expansion of CHP plants seen in the *BAU* scenario does not occur in *EPOL* and *CLI* after 2030.

Achieving the net-zero ambition requires not only the higher penetration of CHP plants in the stationary end-use sectors, but also a shift from natural gas to bioenergy, including wastes, and hydrogen. By 2050, in *CLI*, the share of bioenergy and hydrogen to the total electricity supply from cogeneration reaches almost 60%, when accounting the half of the waste used in incinerators as renewable and the rest as non-renewable energy.

Moreover, the flexible operation of CHP plants is necessary to integrate large shares of non-hydro renewable power in the Swiss energy system by 2050. CHP plants need to follow the electricity load while satisfying the heat demand. Therefore, the deployment of heat storage is a cost-effective flexibility option (see also section 5.4.1.2). The penetration of CHP plants in the future Swiss system depends, therefore, on a number of factors, such as the stringency of efficiency and climate targets, the gas price, the availability of bioenergy resources and other zero-carbon fuels, the need for balancing services, and the relative competition with heat pumps (in buildings) and other renewable sources for electricity supply (Panos and Kannan, 2016).

5.3 Seasonal and hourly dispatch profiles

In the *CLI* scenario, the electricity supply peaks in summer, driven by the availability of the solar resource and the high penetration of solar PV, while the electricity demand peaks in winter (figure 5.5). The shape of the electricity load profile in 2050 does not have the characteristic peaks in the morning and afternoon hours, which are seen today, but it is mostly bell-shaped around noon by when the solar PV production is at its highest levels. This means that the electricity consumption adapts to the new supply patterns and shifts mainly to the noon hours. This is facilitated by the coordinated deployment of a number of flexibility options that decouple the electricity consumption from the provision of the energy service demand, such as storages, smart charging and discharging of electric vehicles, as well as by demand-side management (see also section 5.4).

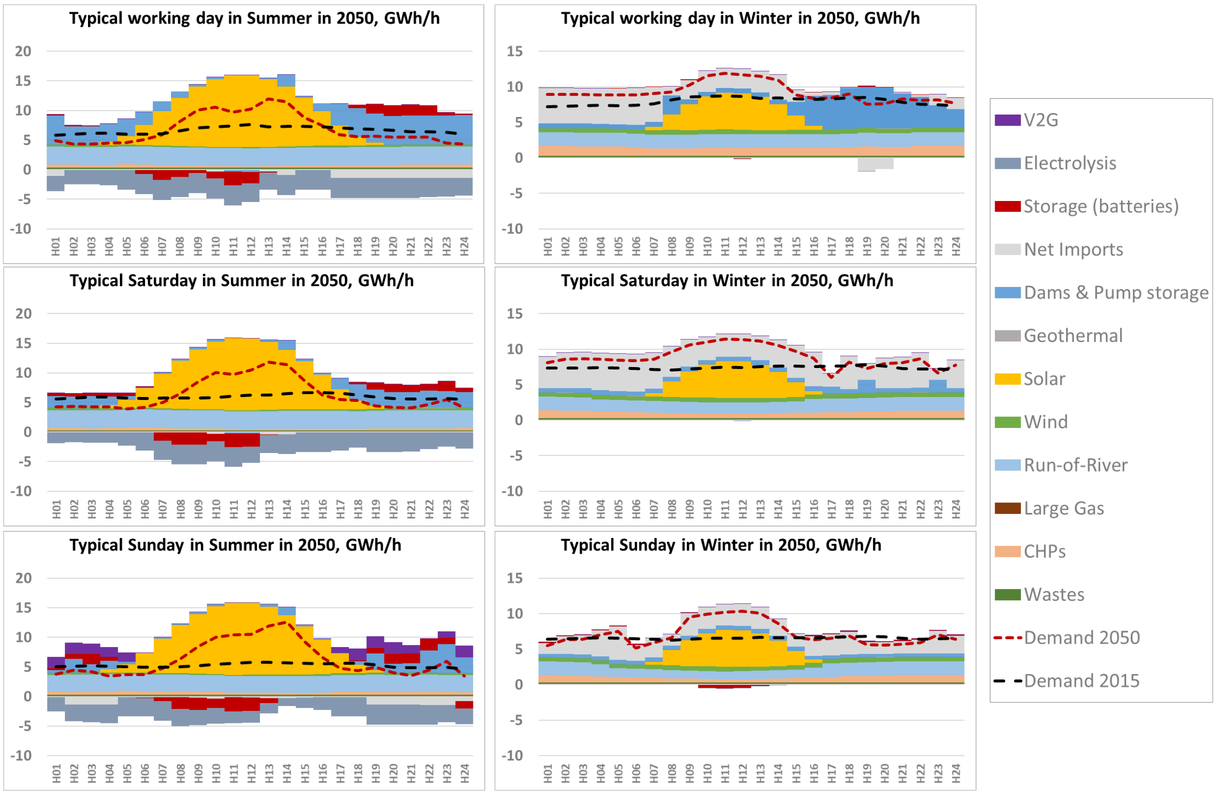


Figure 5.5: *Hourly dispatch profile for average days and hours in STEM in the CLI scenario for the summer and winter seasons of the year 2050*

The dispatch profile of wastes follows is similar to the one observed today, as these plants operate mostly as baseload. The run of river hydropower is seasonally driven, with higher production occurring during the summer. The latter implies that due to the increased solar PV generation, there is excess electricity supply which is mostly consumed in batteries and electrolysers for hydrogen production.

The large scale hydropower offers significant flexibility to the energy system. In summer, electricity from dispatchable hydropower is mainly produced during the hours in which the production from solar PV is zero, i.e. in the early morning and afternoon/night hours. Hydropower contributes to exported electricity in summer during the afternoon hours to the neighbouring countries. In contrast, during winter, the production from large-scale dispatchable hydropower is limited by resource availability, and it mainly occurs during the afternoon hours in working days.

The high share of electricity production from solar in *EPOL* and *CLI* scenarios induces a seasonal imbalance in the electricity system in 2050, which is accentuated after the nuclear phase-out, and which is more pronounced in *CLI* than in *EPOL* (figure 5.6). The current pattern of electricity imports in winter and electricity exports in summer is maintained in all scenarios, notwithstanding the lower exports in *CLI* and *EPOL* compared to *BAU*. The deployment of solar PV in *CLI* to reach the net-zero emissions target by 2050 reduces the import dependency in spring, when assuming a high level of imported electricity prices (particularly during the peak hours), in contrast to *BAU* and *EPOL*.

Thus, in overall, there are less electricity imports in *CLI* than in *BAU* and *EPOL*. However, the high share of solar PV in electricity generation in summer in *CLI* leads to excess supply which is managed through the deployment of electrolysis, storages and demand-side management. In the *CLI* scenario, the gap in the electricity supply and consumption in winter is about 6 TWh, which is covered by imports. At the same time, the excess supply in summer is about 8.5 TWh, of which about 1 TWh is domestically managed by pump hydro and battery storage, and the rest is mainly seasonally shifted via electrolysis as shown in section 4.3.3.

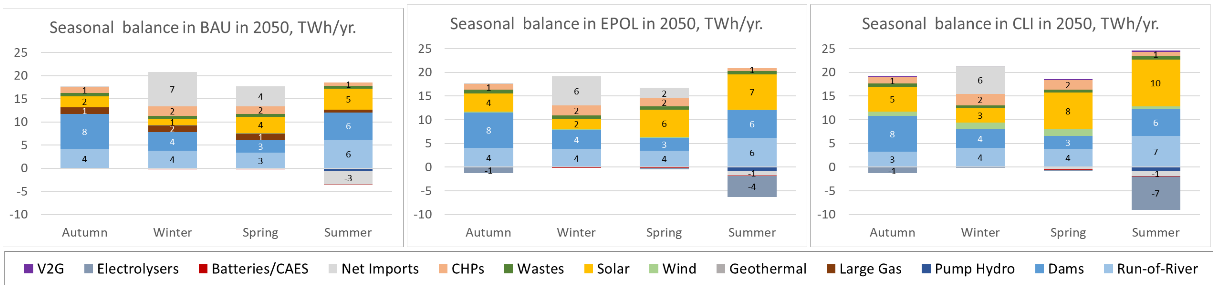


Figure 5.6: *Seasonal electricity supply balance in the three scenarios in 2050*

5.4 Flexibility options

Achieving the net-zero emissions target in 2050 requires a large deployment of non-hydro variable renewable generation, which reaches 45% in the total domestic electricity supply. Because of the significant uptake of solar PV, large seasonal imbalances in the electricity system occur both in the daily and seasonal cycles in the *CLI* scenario in 2050. These imbalances require the deployment of flexibility options at different time scales and different grid levels from high voltage to low voltage, to cost-effectively integrate the new renewables in the Swiss electricity supply. The main flexibility means deployed in the *CLI* scenario are pump hydrostorage, stationary batteries, smart charging (Grid-to-Vehicle) and discharging (Vehicle-to-Grid) of electric cars, buffering services via Power-to-X and sector coupling, as well as demand-side response in the stationary sectors to decouple electricity consumption from the time of the energy service provision.

5.4.1 Storages

5.4.1.1 Electricity storage

In the *CLI* scenario, the structure of the electricity generation shifts from the high voltage in 2015 to the lower grid levels by 2050, as the nuclear power plants are phased out, and the new capacity additions are mainly photovoltaic and CHP systems (figure 5.7). The transition towards a more decentralised and variable power system implies that the energy system will need to be much more intelligent (through digitalisation) and flexible.

The shift towards decentralised generation enables "prosumage" (energy production + consumption + storage), which is facilitated by the costs reduction and performance improvement of distributed electricity supply options and storage. Following the phase-out of the support schemes after 2030, and driven by the increased competitiveness of the solar PV systems, self-consumption is gradually increasing over time and also supporting charging of electric vehicles. As a result, about 90% of the electricity generated in decentralised units is consumed (or even traded) within the distribution grid, while about 10% is feedback to the transmission grid in 2050. Over the time, and facilitated by technological progress and digitalisation, "prosumage" that maximises self-consumption is replaced by more market and system integrated strategies, which also provide flexibility to the system, such as ancillary services and vehicle-to-grid, supported by aggregation of capacities for small-sized prosumers.

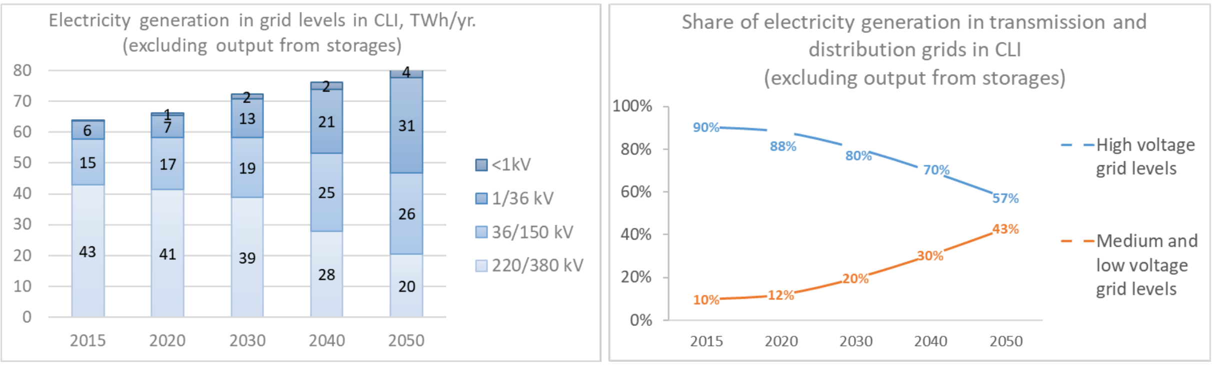


Figure 5.7: *Structure of the electricity generation per voltage level in the CLI scenario, excluding the output from storages*

The above developments imply that the bulk of the distributed generation is mostly balanced at the medium and low voltage levels, rather than relying on large storages at the high voltage grid. In this context, stationary batteries become a crucial component of the operation of the energy system. After 2030, by when the penetration of new variable renewables accelerates, there is a large deployment of stationary batteries, as a cost-efficient option to accommodate the imbalances in supply and mitigate electricity demand peaks. Co-location of batteries with solar and wind generators allows system owners to more predictably manage the power supplied to the grid by combining renewable generator and battery systems. In this regard, pump hydro storage connected to the transmission grid complements the balancing of the electricity system, and it correlates mostly to the cross-border international trade and (cross-border) price arbitrage. As a utility-scale option, pump hydro storage plants provide flexibility to the transmission grid and contribute to the provision of ancillary services, the demand for which increases in 2050 compared to the levels of 2015 (see also section 5.4.2). Existing pump hydro storage power plants remain the least-cost solution for storage services at time scales higher than those provided by the batteries.

However, due to the increased decentralised generation, self-consumption and "prosumage" at the lower grid levels, the construction of new sites for pump hydro storage beyond the already planned investments, e.g. Nant de Drance in Wallis, is unlikely to be economically attractive in (figure 5.8). Balancing the decentralised electricity from solar PV with batteries at the medium and lower grid levels avoids bringing excess electricity to upper grid levels that entails transmission and transformation losses and grid costs. Another factor that hinders the investment in pump hydro storage is that the phase-out of nuclear electricity generation removes from the system about 20 TWh/yr. of low-cost electricity at the high voltage grid levels, which could potentially be a source for pump storage, and this amount is not replaced with equivalent large scale power plants in the high voltage grid. In contrast, the deployment of wind turbines connected to high voltage levels is only one-fifth of the nuclear electricity that is decommissioned. In this context, the hydro pump storage mainly operates with electricity from cross-border trade and electricity from dams, large scale run of river plants, and wind turbines connected to the upper grid levels. As a result, the utilisation of the pump storage remains in 2050 at today's levels, without showing a substantial increase in the operating hours.

Batteries are deployed in all grid levels and present a significant share in new storage capacity additions until 2050. The batteries in the high voltage levels complement pump storage in balancing the transmission grid, especially during the hours when pump storage is not available, either because it is participating in the ancillary markets or it cannot provide the energy storage service due to, e.g. water management restrictions. The medium voltage batteries balance large scale solar PV systems, small run of river hydropower, small wind farms, and CHP units. The batteries in the low voltage levels balance the smaller installations of solar PV panels at buildings. The utilisation of batteries differs according to the grid level they are connected and their application, with the batteries at the upper grid levels being utilised almost twice the time of the batteries in the lower voltage grid levels.

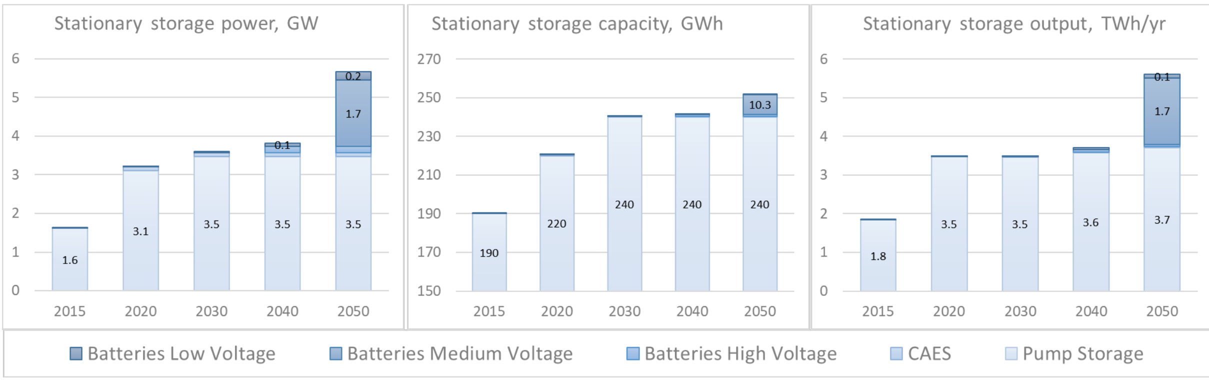


Figure 5.8: *Deployment of stationary electric storage in the CLI scenario in terms of power, storage capacity and output from storages*

Regarding Compressed Air Energy Storage (CAES), we assume that it does not expand beyond the plant in Ticino. The reason for this assumption is that the deployment of CAES is site-specific. To the best of our knowledge to the time of the study, there was a lack regarding a detailed evaluation of suitable sites and the related costs.

5.4.1.2 Thermal storage

Thermal energy storage becomes an important technology in the future energy system of Switzerland and in the context of achieving net-zero emissions by 2050 (figure 5.9). In the *CLI* scenario, the penetration of thermal energy storage is crucial to integrate large shares of solar space and water heating by decoupling the energy service provision from resource consumption. Thermal storage also supports the flexible operation of CHP plants in the electricity supply, by enabling electricity load-following operation in order to be able to balance the electricity system and to integrate large shares of renewable electricity. In this regard, the overall thermal energy storage needs increase over time and for both high and low temperatures. Concerning the timescale of the thermal energy storage, there is an expansion of the short-term storage and a deceleration in the growth of the seasonal thermal storage. This development is mainly attributable to the electrification of the heating system, as flexibility measures are deployed to cope with seasonal imbalances in the electricity supply and demand, which mitigate to some extent the need for additional seasonal balancing measures for the (electrified) heating system.

From the energy market perspective, three main forms of thermal energy storage occur in the future Swiss energy system: local storage attached to the operation of a solar PV, CHP power plant or other industrial processes, local community energy storage, and virtual community energy storage. The community energy storage is also grid-based, independently if there is a coherence between the community and the specific physical storage territory. In the case of the virtual energy storage a collection of participants form a virtual community, typically through intermediaries. The liberalisation and restructuring of the energy sector can provide enabling conditions for virtual community-scale energy storage. Sensible (i.e. water tanks) and latent (i.e. phase change materials – PCM) heat storage is used for residential and commercial applications, while thermochemical storage (TCS) is mainly used for industrial applications.

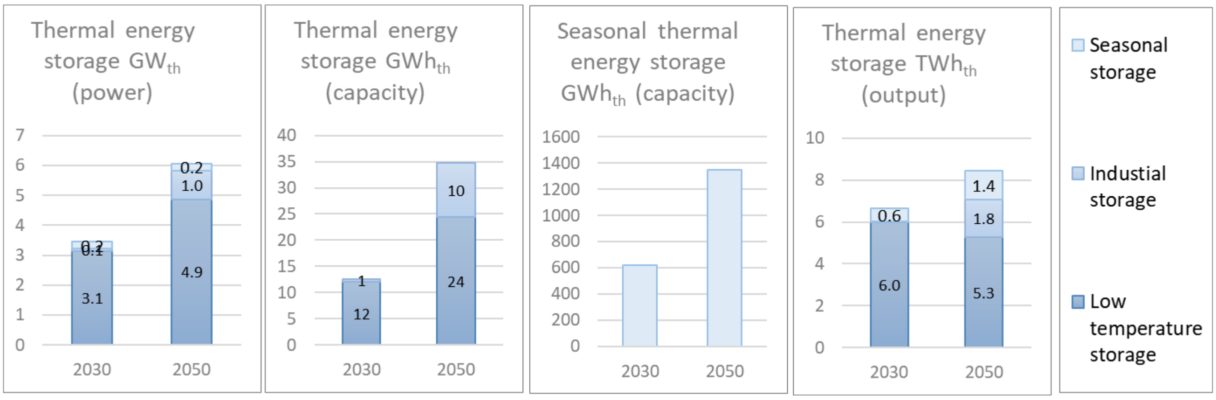


Figure 5.9: *Deployment of thermal energy storage in the CLI scenario at different temperatures and time scales from intraday to seasonal storage*

Thermal storage brings along economic and non-economic values, such as increased self-consumption, grid relief through peak savings, emergency services for critical infrastructures, energy security and resilience. However, thermal energy storage technology faces some barriers to market entry, and the cost is a key issue among them. One of the major constraints is the low construction rate of new buildings since it is more cost-efficient to integrate thermal storage during the construction of the building instead of installing it afterwards (IRENA, 2013).

5.4.2 Ancillary markets

As the electricity system becomes more whether-dependent, the imbalances in supply are amplified by the increasing penetration of solar PV and wind turbines from 2015 to 2050. As a result, the need for ancillary services is higher in 2050 compared to 2015 levels. Hydropower and pump storage remain the major providers of operating reserves[1] (figure 5.10).

New business models are also emerging in the next decades, in which utilities act as smart system integrators that operate flexible distributed electricity generation units as virtual power plants, such as batteries and CHP plants equipped with heat storage systems and/or flexible heat extraction. These virtual power plants contribute to meeting the needs for operational reserves towards 2050.

[1]It should be noted that STEM considers the amount of the capacity that is available to the ancillary services markets, which can be called when it is needed, and not the capacity that is actually called upon the activation of the reserve.

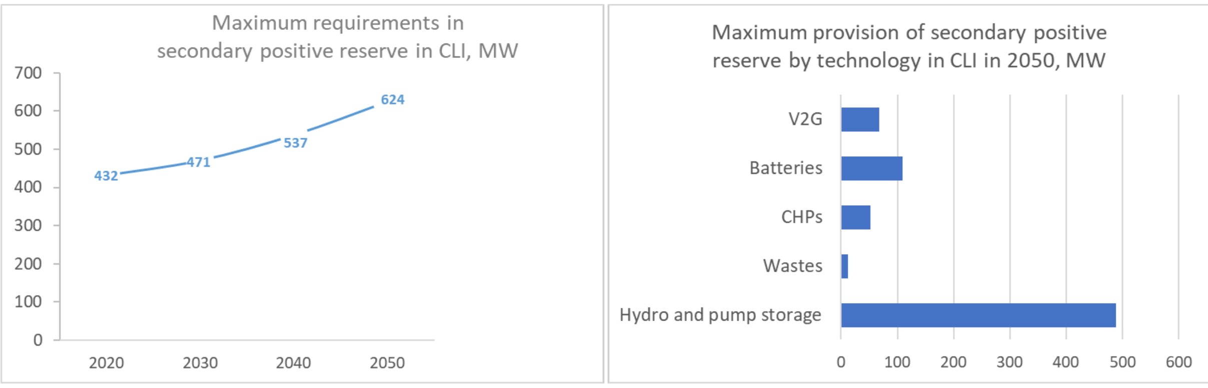


Figure 5.10: *Demand for secondary positive reserve in the CLI scenario (left) and maximum provision of the secondary positive reserve by technology in the CLI scenario (right), in 2050. The estimation of reserve demand in 2020 is model result. The numbers in the right chart do not add*

Hydropower mainly provides reserves from the early morning until afternoon hours (figure 5.11). During the peak hours in the afternoon, the provision of the reserve from hydropower is reduced due to the need to participate in the electricity market to supply the demand (either domestic in winter, or abroad in summer). Pump hydropower storage and large scale batteries in the high and medium voltage levels are available almost on a 24h basis for reserve provision. A new option for reserves that mainly emerges after 2040 is the Vehicle-to-Grid that is supported by the introduction of electric vehicles with discharging functions that enable bidirectional power transmissions between EVs and the grid, EVs and other electronic devices, as well as between two EVs.

It should be noted that the charts in figure 5.11 should be read as the capacity which is ready to provide a reserve. If the reserve is activated, then the provision of reserves starts with the unit providing the lowest bid and progressively proceeds to the units with higher bids until the demand for the reserve is met. However, STEM does not model the activation of the reserve. Therefore the capacities shown in the figure are not necessary entirely used when the reserve is activated, as this depends on the actual (real-time) demand for reserve.

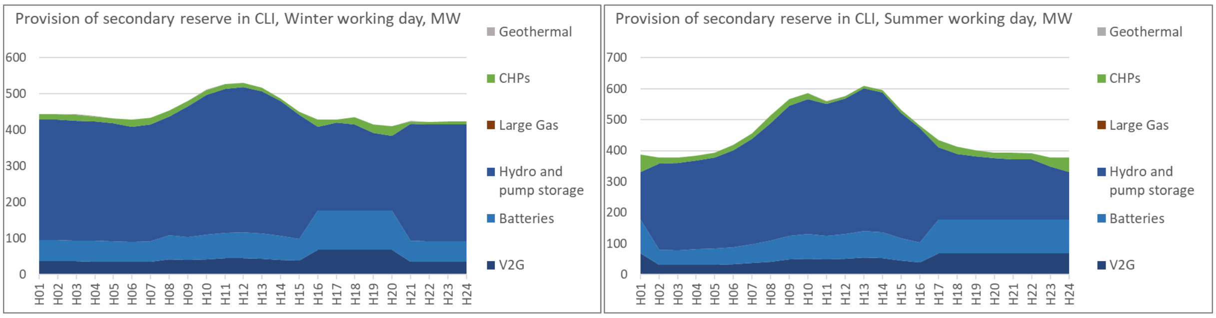


Figure 5.11: *Contribution per technology in the provision of secondary positive reserve in the CLI scenario in 2050, across different average hours and days of STEM*

5.4.3 Cross-border trade

The transformation towards a low-carbon and renewable-based electricity system in Switzerland and Europe requires extensions of the transmission grid. However, the construction of new lines is progressing very slowly in Europe (ENTSO-E, 2015). Cross-border infrastructure projects are often facing significant delays related to public acceptance issues, followed by technical issues, dependency on other projects, authorisation procedures and terrain issues. In the *CLI* scenario, as stated in section 2, we assume an expansion of the cross-border capacities between Switzerland and its neighbouring countries aligned with the assumptions of ENTSO-E TYNDP 2018 (Marcucci et al., 2020).

Cross-border trade delivers three key benefits to the Swiss energy system. At first, the more market parties have the option to make use of cross-border trade, the lower the costs of the energy transition for energy users are. The second is that the more electricity supply in Europe becomes weather dependent, the more often differences in generation costs across the EU occur, which creates a constant change in demanded directions of trade benefiting the parties with access to the locations where generation costs are the lowest. And the third benefit is the effect on flexibility. The more power systems are connected to each other, the more options become available or adapt their generation and load to realise network balance, which has a downward effect on the electricity prices. Finally, a more integrated market makes individual market parties less indispensable and, hence, their ability to behave strategically is reduced (Panos and Densing, 2019). Scenario analyses with STEM have shown that under a restriction of the cross-border trade capacities, the energy transition costs for the Swiss consumer are very high compared to the cases with no trade limits (Fuchs et al., 2017).

However, the magnitude of the imported fuels and electricity and their nature, often raises specific energy security and other wider geopolitical issues. Energy efficiency and conservation, as well as technology switching and circular economy, help in limiting the demand. Moreover, in combination with the switch to domestically produced low carbon energy carriers, the above measures can reduce energy imports when import prices are high. This is particularly the case of the *CLI* and *EPOL* scenarios, where the deployment of large scale efficiency measures, the increased electricity from local energy resources, and the high import prices (especially in peak hours) result in less net imports of electricity compared to *BAU*, despite the significant electrification of the demand. Also, especially in the *EPOL* scenario, the combined implementation of efficiency measures and renewable targets can also enable net exports of electricity in the near-term, by when nuclear power has not been entirely phased-out. Figure 5.12 presents the trajectory of the electricity net imports in the three scenarios, which also depend on the assumptions about the trajectories of the electricity import costs and cross-border capacities (see also section 2.4).

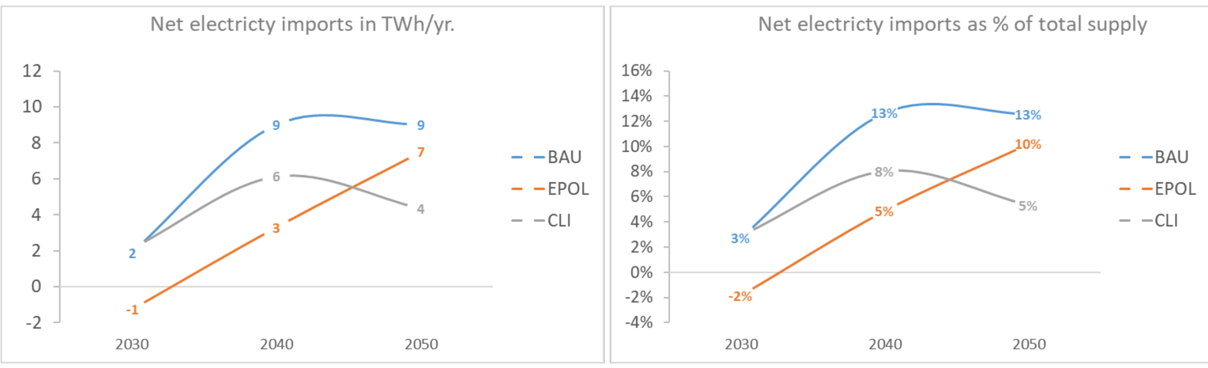


Figure 5.12: *Net imports of electricity in TWh/yr. (left) and as a share in total electricity supply (right)*

Like the current situation, in all the three core scenarios, the cross-border trade fills the electricity supply gap in winter, especially after the nuclear phase-out. The cross-border trade pattern in an average working day during winter and summer is shown in figure 5.13.

During the winter, the electricity net-imports occur in all scenarios in the early morning and the noon hours. In the afternoon, storages mostly discharge and hence mitigate the need for imports and enable electricity exports from hydropower, particularly at those hours when cross-border electricity imports prices are high. During summer, the net imports in both *EPOL* and *CLI* scenarios are close to zero. In the *BAU* scenario, the net-imports of electricity follow more or less the pattern observed today, in which exports of electricity occur in the early morning and afternoon hours. The intra-day variations of the cross-border trade are smoother in *CLI* than in *BAU* due to the deployment of other flexibility options that contribute to the balancing of the electricity system.

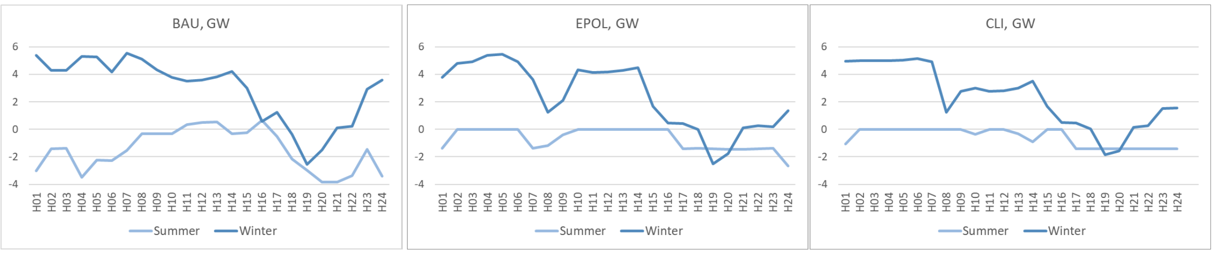


Figure 5.13: *Profile of net imports of electricity on an average working day in summer and winter in 2050. Imports are displayed as positive and exports as negative values*

5.4.4 Grid-to-Vehicle (G2V) and Vehicle-to-Grid (V2G)

Compared with conventional demand response options and technologies, electric vehicles (EVs) are potentially better able to adjust charging and discharging times due to their relatively long parking times (Liu et al., 2016). During this time, by when they do not provide the mobility service, EVs are potentially free to deliver balancing services to the grid via smart charging and discharging. Hence, if EVs are deployed at a large scale, they could become an important resource of flexibility.

In theory, there are noticeable differences between flexibility provided by electric vehicles and conventional demand response resources. The conventional demand responses require consumers to adjust electricity consumption behaviours by decoupling it from the provision of the energy service, which represents a (behavioural) constraint in their deployment. In contrast, as EV charging and driving do not occur simultaneously, adjusting the charging times while the vehicle is parked would not typically affect EV owners' daily patterns. However, it entails a technical challenge because extensive cycling of the EV batteries could accelerate their degradation. The latter is also taken into account in the analysis with STEM, since extensive cycling induces battery replacement costs in the model.

In the *CLI* scenario, the increased electrification of mobility facilitates not only the decarbonisation of the transport sector, but it also results in substantial power flows between the electricity and transport systems. As shown in figure 5.14, the storage capacity of the batteries of the electric vehicles is exceeding by far the capacity of the stationary batteries (compare figure 5.8), and it can be argued that it is comparable with hydro pump storage. The largest share in available storage capacity is on private cars, due to the large size of the fleet. However, these batteries are much smaller in size than busses and trucks, and efficient integration of their energy storage services in the grid would require coordination among several thousands of car owners.

Moreover, the cost-efficient integration of the electric vehicles in the Swiss energy system would also require coordination between the electricity needs in transport and the rest of the end-use sectors. In addition, it would require coordination with the rest of the flexibility options deployed in the energy

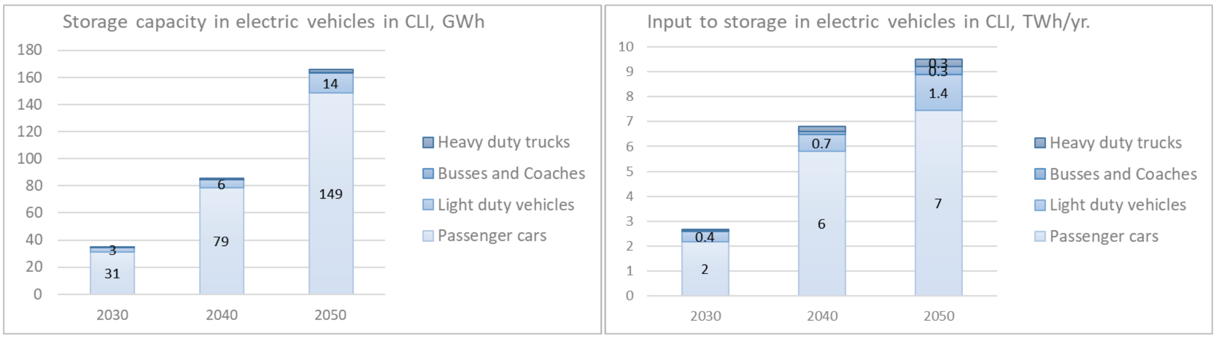


Figure 5.14: *Electricity storage in electric vehicles (left) and electricity consumed for charging the electric vehicles (right), in the CLI scenario. The figure excludes trams, trolleys and other road transport such as military vehicles, etc.*

system, such as the stationary batteries. In general, EV owners would shift charging to the cheaper hours, although there would also be owners inelastic to price signals.

As shown in figure 5.15, the charging of the private electric cars mainly peaks during the noon hours in 2050, across all seasons. This pattern coincides with the assumed driving profile, as in the noon hours, there is a significant reduction of the driving activity compared to the afternoon hours. It is also triggered from the positive correlation between the hours with good availability of the solar resource and low needs for driving, which in turn can enable smart charging of EVs at lower costs.

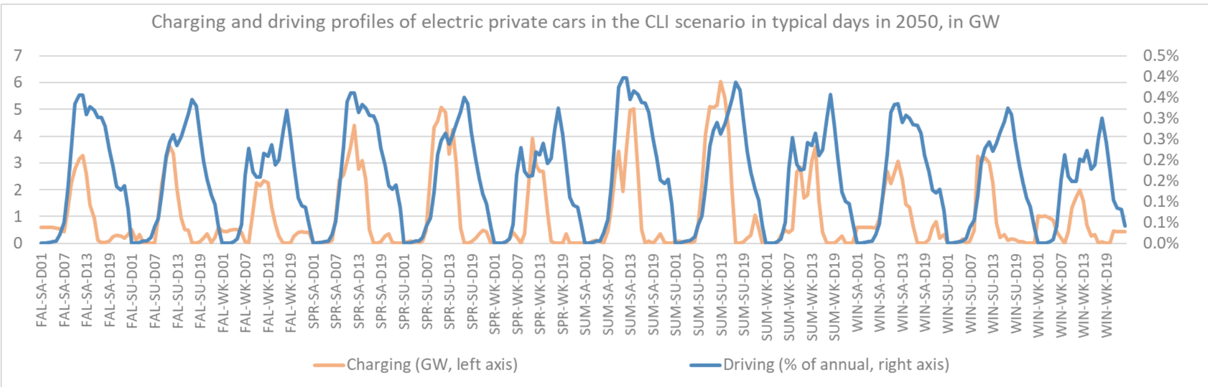


Figure 5.15: *Charging and driving profiles of private electric cars in different average days in the CLI scenario in 2050 (WK=working day, SU=Sunday, SA=Saturday, FAL=autumn, WIN=winter, SUM=summer, SPR=spring, D01-D24=hours)*

Looking at the individual seasons, the overall charging requirements are generally lower in autumn and winter than summer and spring because of the assumed lower mobility demand in these seasons (Mathys and Justen, 2016). In summer, the charging power peaks in Sunday's noon hours, where there is excess solar electricity, and the cars need to be also fully charged for the week ahead. During the working days in summer, and mainly before the noon hours, there is a decrease in the required charging power. This is attributable not only to the lower driving activity in the next hours that mitigates the need for charging but also to cost-effective coordination of the EV charging with stationary batteries that are charged with excess electricity from solar PV during these hours to provide electricity in the night hours. This coordinated action between the flexibility from EV and electricity storage provides a quick response generation to the electricity grid.

Next to the smart charging, electric vehicles could also play a role as distributed energy storage to provide services to the power grid while there are parked. This service is facilitated by the development of EV-grid bidirectional communication protocols and standards. To be able to provide such a Vehicle-to-Grid (V2G) service, electric vehicles need to have three required elements: a power connection to the grid, control (or logical) connection necessary for communication with grid operators, and precision metering on-board the vehicle. The electricity provided by V2G can be competitively used for ancillary services (see also section 5.4.2), and to some extent, it can be also sold to the energy market, notwithstanding the small amount of energy output and the relatively high production costs compared to other supply options. Facilitated by digitalisation that enables smart integration of electric vehicles into the energy system, EVs can serve as distributed generators with the advantage that they can switch to supply power back to the grid within milliseconds and much faster than conventional generators. In addition, given that the EVs mainly exchange electricity with the distribution grid level, using EV batteries to provide G2V and V2G services could minimise the overall transmission losses and costs compared to using centralised large scale storage, e.g. large batteries or pump storage plants. Via economies of scale, today's high upfront costs that constitute these balancing services of the electric vehicles unattractive can be reduced as the number of electric vehicles increases over time.

As shown in figure 5.16, the provision of power from V2G is also coordinated with the deployment of other flexibility options. It mainly occurs in summer and spring seasons where the availability of excess electricity is higher than in winter and autumn. Hence, at that time, the cost of the energy discharged by EVs is lower, because they have been charged with excess solar electricity at noon (as also shown in figure 5.15). Moreover, due to the higher contribution of variable renewable electricity from solar in spring and summer, the system imbalances are also larger during these two seasons, increasing the need for additional flexibility measures.

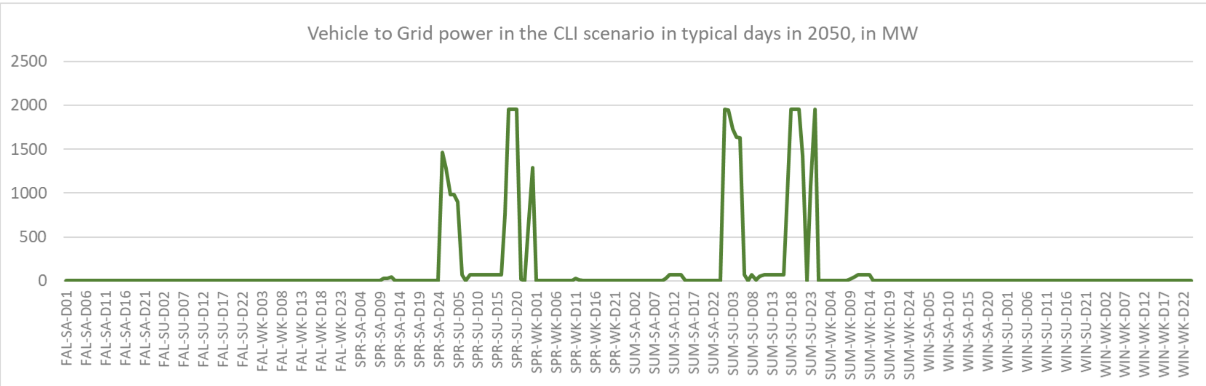


Figure 5.16: *Power provided from Vehicle-to-Grid in average days in the CLI scenario in 2050 (WK=working day, SU=Sunday, SA=Saturday, FAL=autumn, WIN=winter, SUM=summer, SPR=spring, D01-D24=hours)*

As with the smart charging, the smart discharging of the electric vehicles needs to be coordinated with the rest of the options deployed to balance the electricity system. For instance, EVs that are parked during the afternoon hours can be discharged during this time, and this power can be used to provide electricity to the distribution grid. The highest provision of V2G power occurs during the night hours of weekends. This is because there is higher availability of low cost (or even zero cost excess) electricity during the noon hours on weekends. Hence, it is cost-effective to use this electricity through V2G schemes, by charging the cars during the noon hours on weekends and discharging them during the afternoon and night hours. On average, in the *CLI* scenario, about 7% of the electric vehicles in 2050, contribute to V2G schemes.

5.4.5 Demand-side management and flexibility options in the stationary sectors

Demand-side management and flexibility in the stationary sectors are becoming increasingly important options in the future Swiss energy system. In the analysis with STEM, two types of demand flexibility are examined: the decoupling of water and space heating from electricity consumption via electric heaters and heat pumps with thermal storage, and demand-side response regarding electric-specific uses such as appliances in households and electric-based processes in industrial and commercial sectors. However, the potential of demand-side management in the stationary sectors cannot be easily captured and quantified as it is dependent on the individual situation of the area observed.

5.4.5.1 Demand-side management in water and space heating supply

Figure 5.17 shows the amount of heat shifted on an intraday basis for hot water and space heating, as well as the equivalent electricity consumption after the adjustment for the efficiency. The thermal storage capacity to support this operation is included in the numbers reported in figure 5.9. The shifts mainly occur in the residential sector, as the amount of space and water heating that can be managed is significantly higher than in industrial and commercial applications. The amount of the electricity that it is shifted in the *CLI* scenario for the provision of hot water and space heating is equivalent to 11% of the total electricity consumption for heating purposes in the residential sector in 2050.

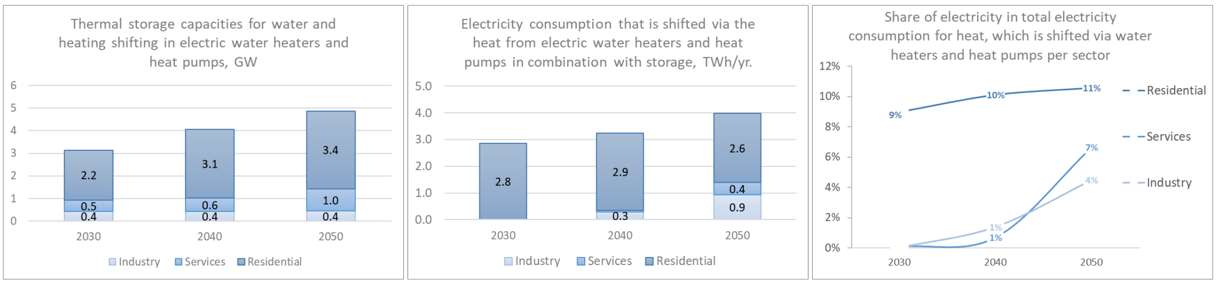
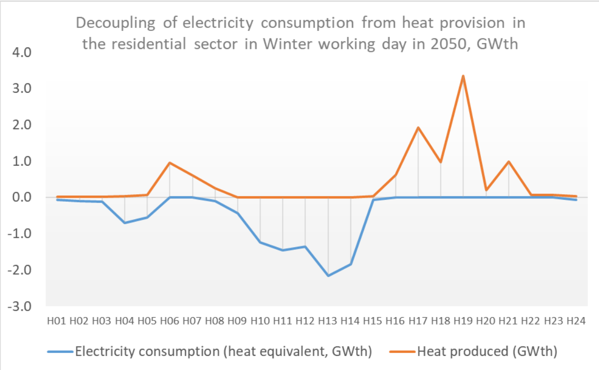


Figure 5.17: *Heat shifted via the decoupling of electricity consumption from heat provision in water and space heating (left), and the corresponding amount of shifted electricity after adjusting for the heat production efficiency in the CLI scenario (middle). The chart's right-hand side presents the share of the electricity shifted in the total electricity consumption for space, water, and process heating in each sector. The saturation in the amount of shifted electricity seen in the residential sector in the last decade is attributable to the efficiency improvements in the provision of water and space heating*

Typically, electricity consumption occurs when the prices are low, such as during the noon hours or the early morning hours. The produced heat is stored, and then it is released within a typical window of max 5-7 hours, by when the electricity prices are high again, such as the afternoon hours. Figure 5.18 presents the typical pattern of the management of heating and electricity loads via shifting with the use of electric water heaters and heat pumps in the *CLI* scenario in a winter working day and a winter holiday in 2050.



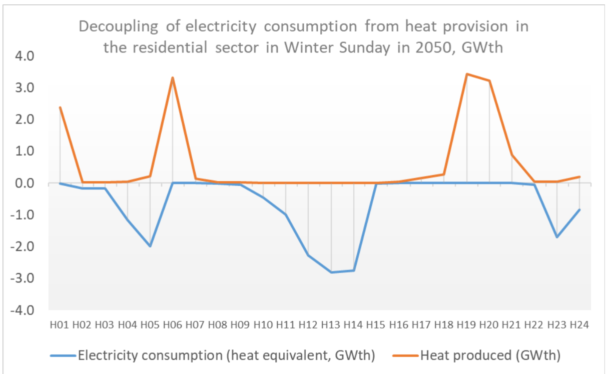
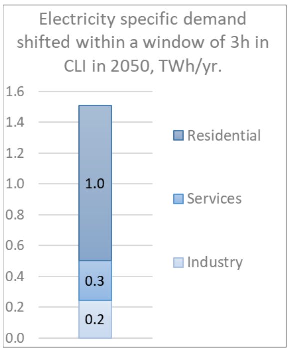


Figure 5.18: *Decoupling of heat supply from electricity consumption in water and space heating in winter working day (left) and winter Sunday (right) in the CLI scenario. The figure refers to the amount of heat shifted, as electricity consumption has been adjusted for the conversion efficiency*

5.4.5.2 Demand-side management in other electric uses in the stationary sectors

Demand response is another form of demand-side management associated with the changes in electric usage by end-use consumers from their normal consumption patterns in response to changes in electricity price over time. A number of uses of electricity such as cooking and washing in residential, as well in the commercial sectors and industry (e.g. metals and chemicals sectors), can be shifted in time to benefit from lower electricity prices and decouple the provision of the energy service from the consumption of electricity. A recent study in Switzerland has estimated the sociotechnical potential of such demand response schemes about 311-344 MW for households, 112-304 MW in the services sectors and 124-290 MW in industry (Vossebein et al., 2019).



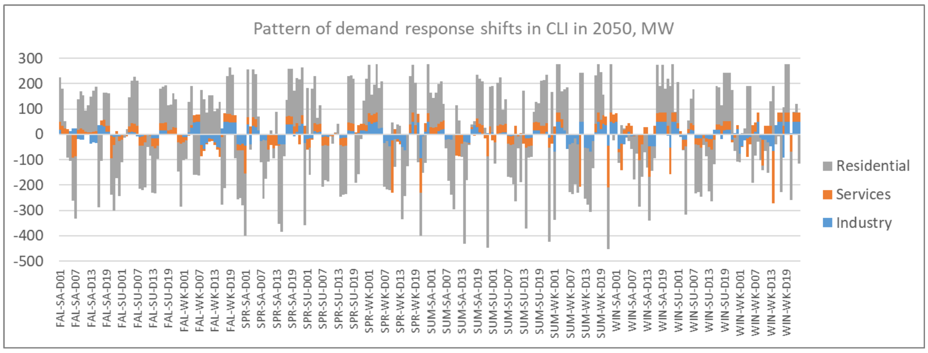


Figure 5.19: *Electricity shifted via demand response that enables a change in the consumption patterns for electric uses in the residential, services and industry (left), as well as the demand response intraday patterns (right) in average days (WK=working day, SU=Sunday, SA=Saturday, FAL=autumn, WIN=winter, SUM=summer, SPR=spring, D01-D24=hours). Negative values mean reduction of demand and positive values increase of the demand. The figure is relative to the demand response of 2015*

In the *CLI* scenario, the demand response on electric stationary end-uses becomes of increasing importance after the nuclear phase-out and following the high deployment of variable renewable electricity. As shown in figure 5.19, about 1.5 TWh of electricity for electric specific stationary uses are shifted by changing consumption patterns to benefit from reduced prices in 2050 (figures refer to shifts additionally to the ones already observed in 2015). The largest potential for shifts is shown in the residential sector, followed by services and industry. A maximum of about 400 MW of electricity demand is shifted in the residential sector, 220 MW in services and 110 MW in industry in 2050.

5.5 Transition enablers, challenges and opportunities

The analysis shows that the most important single driver for a decarbonised energy system is the growing role of electricity, both in final energy demand and supply of e-fuels and hydrogen. The incremental needs in electricity supply are mostly met by solar and wind. Thus, there is a shift from an electricity production that follows demand to a largely weather-driven production, which in turn imposes challenges in technology and regulatory fields (EC, 2018).

The installed power generation capacity doubles between 2015 and 2050. Given that solar PV has the lion's share in the future capacity additions, spatial planning and new building construction regulations to support this expansion could be an important challenge. In order to be able to almost double the installed capacity of solar PV in each decade from today until 2050, engaging citizens and local authorities would also be essential. The regulatory framework to facilitate the further development of electricity supply and consumption infrastructure will be needed to be based on cooperation across Transmission System Operators and Distribution System Operators, as well as the opening of the market in the most cost-effective manner.

A more decentralised and variable power system implies a need for more flexibility. Better interconnections in all grid levels, more energy storage, faster-reacting grids, deeper demand response and flexible generation units would need to be on the focus of research and innovation in the future. In this regard, a more intelligent and digitalised power sector is needed (IEA, 2017).

In the future energy and power systems, there will be opportunities for centralised and decentralised storage, including storage options via hydrogen and e-fuels. There will also likely be opportunities for flexible consumers (individual ones if representing large demand or those collectively offering their capacities through aggregators), who pursue demand side management, "prosumage", grid-to-vehicle and vehicle-to-grid schemes, supported by distributed storages. Hence, electricity storage can occur in sectors other than power itself, for instance, in buildings and transport sectors. As there are multiple options for storing and converting both electricity and heat in the future energy system, and at the same time sector coupling emerges and becomes stronger towards 2050, an integrated approach is required regarding access to relevant infrastructures. It is crucial that sectors do not work in isolation, particularly for mobility, buildings, and power sectors.

In the mobility sector, the efficient integration of Grid-to-Vehicle and Vehicle-to-Grid provides a number of advantages to the power system, as EVs can act as distributed generators with fast response times, suitable for both demand response and provision of ancillary services (Liu et al., 2018). However, such an operation of electric vehicles would require service providers and grid companies to directly deal with the end-users in bidirectional power purchases, which will involve two-way financial flows. Moreover, the pricing of such services from EVs would be a challenge, in order to incentivise and aggregate sufficient numbers of electric vehicles to provide reliable system services with the reliability at scale on a par with other generators.

In the stationary sectors, demand-side management (DSM) emerges that mitigates peak loads, improves the operation of transmission grid by avoiding congestion and reduces the need for grid reinforcements (Strbac, 2008). DSM also balances excess production from solar and wind electricity and, hence, it improves the overall system performance. Besides the balancing of electricity loads, also the heat loads would need to be cost-effectively managed in the future distributed power system, in order to enable the decoupling of electricity consumption from the provision of heat from electric water heaters and heat pumps. However, there are also challenges associated with DSM. Its implementation requires a significant deployment of ICT options, more clarity regarding the business case for DSM, and appropriate regulatory framework to optimise its benefits that often accrue to different participants (e.g. industry, consumers, utilities, system operators) (Strbac, 2008). DSM solutions tend to increase the complexity of the system operation compared to the traditional solutions, and confidence in their use needs to be developed, as it is expected that in the (near) future DSM will become more cost-efficient than current system balancing options.

While the current typical daily electricity consumption profile has two distinct peaks (one in the morning hours and one in the early evening hours), it becomes bell-shaped towards 2050. As demand adjusts to the supply conditions, the absence of the two peaks in the load curve is due to increased electricity use for charging storage in all sectors for electricity, heating and mobility uses and for Power-to-Gas. This change poses challenges for utilities, which need to improve and advance their current forecasting models to account for demand response and electric vehicles charging behaviour. Some of the challenges include: a) complexity in quantifying the factors responsible for electricity demand; b) data availability regarding consumers' reaction to different price signals; c) emergence of mixed consumer groups, some of which have smart meters and some traditional meters; and d) management of the big data sets that are generated by smart meters (Panos et al., 2019a).

Chapter 6

District Heating

6.1 Supply and demand

Today, waste incineration plants provide the largest amount of district heating to the Swiss energy system, followed by gas CHP plants and heat plants. The largest consumers are the residential and industrial sectors. Figure 6.1 presents the developments in both supply and consumption of district heating in the three core scenarios. A prevailing trend in all scenarios is that the district heating expands in the next decades. However, there is a saturation in its growth due to the deployment of efficiency measures and increased on-site consumption of heat from cogeneration plants (see also section 3.2). In *EPOL* and *CLI* scenarios, the share of heat consumption from district heating in total final energy consumption increases in all sectors over time, and it is higher than its share in the *BAU* scenario over the period of 2020-2050.

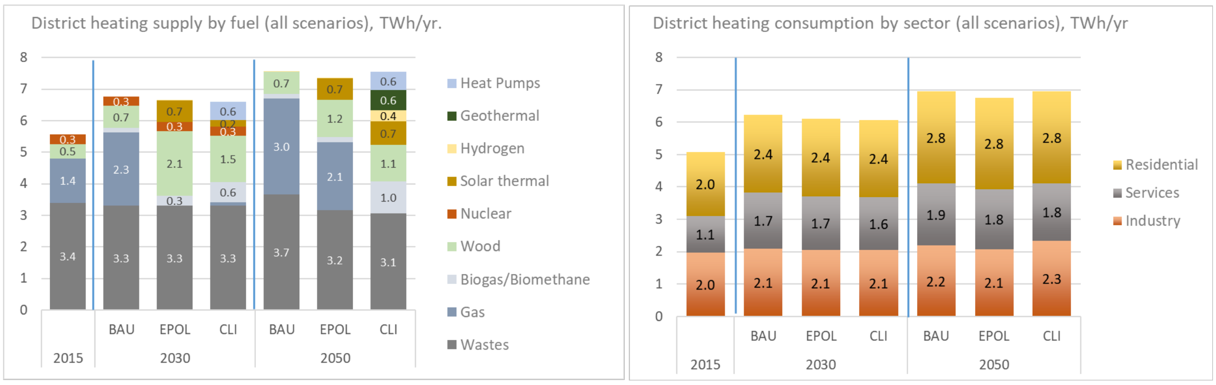


Figure 6.1: *District heating production fuel mix (left) and consumption by sector (right) in the three core scenarios; "geothermal" refers to deep geothermal, "heat pumps" refer to heat pumps using heat from waste water, "solar thermal" refers to solar thermal district heating networks*

The district heating supply in *EPOL* and *CLI* scenarios moves away from gas by 2030, with wood and solar-based district heating emerging in larger scales. In the post-2030 period, new zero-carbon energy carriers such as geothermal heat, heat from waste water heat pumps (see (Gutzwiller et al., 2008) for an assessment of their potential), and hydrogen from renewable and low-carbon electricity gain share in the fuel mix in district heating supply in the *CLI* scenario. In fact, in the *CLI* scenario, the district heating is carbon-free after 2040. In contrast, in the *EPOL* scenario, there is a come-back of gas-based district heating in the last decade of the projection period. This is because in *EPOL* gas-based cogeneration increases in the last two decades to meet the efficiency targets and fill the electricity supply gap due to the phase-out of existing nuclear capacities, since there is more limited deployment of renewables (compared to *CLI*) because of the absence of strong climate policy.

The residential sector has the largest share in the district heating demand in all scenarios, followed by industry. Thus, the prevailing trend observed today also remains in the future. The residential sector increases its share in district heating consumption in all scenarios, and especially in *CLI*. The expansion of district heating in *CLI* is essential to integrate new renewable energy by mitigating upfront costs for the end-consumers. In the *EPOL* scenario, the increase in the uptake of district heating in the residential sector constitutes a cost-effective option to harvest efficiency gains in water and space heating. By adding district heating to buildings, it is possible to utilise surplus heat from power plants, industry, and waste incineration, while also using more renewable energy, including large-scale solar thermal and geothermal. The consumption of district heating in industry slightly expands from the levels of today in all scenarios. This is mainly due to the increased penetration of cogeneration and on-site heat consumption, which prevent further deployment of district heating in industry. This is mainly the case in the *CLI* scenario, where the heat produced and consumed on-site is the highest among the core scenarios.

6.2 Transition enablers, challenges and opportunities

District heating can flexibly integrate different renewable energy sources. Also, it offers the possibility to use local heat resources, which otherwise would be unused due to technical, spatial or economic constraints. Moreover, district heating allows linking CHP plants and heat pumps with thermal storage facilities (Quiquerez et al., 2017). To this end, the transition to net-zero emissions in 2050 entails an essential role for the district heating network operators, as future district heating is largely based on renewable energy sources such as bioenergy, solar and geothermal. The district networks are also transformed with the integration of storages, which is required to address building automation, prosumers' involvement, and smart integration of energy systems (Hast et al., 2018).

Energy savings in the stationary sectors and demand response schemes entail the risk of reducing energy density in the network and consequently increasing the operational and investment costs of district heating. The analysis shows that although the expansion of the district heating continues until 2050, the utilisation of the network is being reduced (but still covering capital and operating costs).

In addition, local conditions and specific features, as well as strategies or decisions made at the municipal level could affect the role of district heating in the future energy system (Chittum and Østergaard, 2014). When the district heating networks are viewed as similar to electricity and gas networks and are embedded in an overall plan across multiple infrastructures, then local planning policies can be carefully designed, while at national scale coordination and alignment between owners, neighbouring infrastructures, supply chain actors, and customers can be achieved. Such a coordinated action between local and national planning can lift barriers related to the expansion of the district networks, such as: a) inconsistencies in the pricing of heat from district heating, where transparency is essential, b) financial appraisal and technical feasibility; c) need for high-quality consultancy support; d) possibility to sell electricity from CHP plants (especially if these are gas-fired); and e) need for contract mechanisms and standardised contracts between providers and consumers (BRE, 2013).

Chapter 7

CO_2 emissions trajectories, and carbon capture, utilisation and storage

Carbon Capture and Storage is a mitigation option that is applicable for large-scale stationary plants, mainly in the upstream, energy conversion, and industry sectors. With CCS connected to fossil or waste plants in the energy conversion sector, or to plants in industry, one can reduce emissions to a bit above zero and with bioenergy with carbon capture and storage (BECCS) and direct air capture carbon capture with storage (DACCS) below zero. The achievement of the net-zero emissions target in 2050 would require the deployment of negative emission technologies (NETs) to offset emissions from the energy system that cannot be reduced to zero, mainly from industry. If emissions from agriculture, other than fuel combustion, are to be offset by the energy system too, then the need for NETs becomes even higher. However, in the current analysis, we do not include agriculture emissions, other than the fuel combustion in the sector. Hence, the requirements for carbon capture, utilisation, and storage reported in this chapter refer to emissions from the energy system (fuel combustion) and industrial processes only.

In the analysed scenarios, the only technological options envisaged to capture CO_2 are the capture of carbon from the combustion of biomass/wastes (BECCS), fossil fuels, DACCS and process-related emissions, such as in the cement industry. The captured carbon is directly stored underground, or utilised, or even transported and stored outside Switzerland. We do not consider options such as afforestation and reforestation, biochar production, enhance weathering and soil carbon sequestration. Afforestation and reforestation can lead to a reverse effect and release CO_2 by exposure to natural damages (Beuttler et al., 2019). Biochar from pyrolysis, contrary to bioenergy, does not supply by itself energy for the rest of the economy, while pyrolysis being itself energy consuming and competing for the biomass resource with the energy system. The synthetic gases produced from pyrolysis are mostly H_2, CO and CO_2, while the bio-oil tends to become viscous due to ageing. Soil carbon sequestration can also be a reversible process because the carbon in soil is continuously decomposed. Enhanced weathering refers to crushed minerals that bind CO_2 chemically and then can be stored in products, in the soil. However, to implement this option large amounts of heavy rock need to be collected, crushed into a fine powder and transported, which make this option to have a steep price tag, higher or equal to DACCS (Strefler et al., 2018), on top of possible environmental risks and the fact that it is an energy-intesive process without producing energy for the rest of the economy. A comprehensive review and potentials for the different carbon dioxide removal options in Switzerland is given in (Beuttler et al., 2019).

7.1 CO_2 emissions from the energy system and industrial processes

The CO_2 emissions from fuel combustion and industrial processes, excluding international aviation, peak in all scenarios in 2010. Achieving net-zero emissions in 2050 requires additional reductions in the cumulative CO_2 emissions budget over the period from 2015 to 2050 of about 500 Mt CO_2 in the *CLI* scenario relative to *BAU*. The residential, services and transport sectors are decarbonised, while the remaining emissions in the energy system in 2050 are from industry and industrial processes.

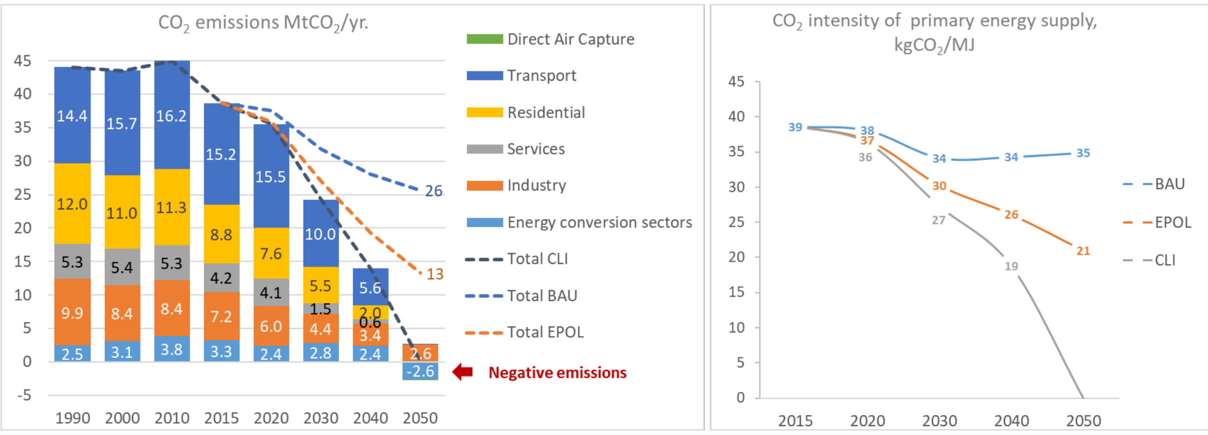


Figure 7.1: *CO_2 emissions from fuel combustion and industrial processes excluding international aviation (left), and carbon intensity of the primary energy supply (right). The emissions in industry also include emissions from fuel combustion in on-site CHP plants and industrial processes. The emissions in services and residential sectors include emissions from fuel combustion in on-site CHP plants too. The emissions in energy conversion sectors refer to emissions from waste incinerators, district heating plants, hydrogen production facilities and other biofuel and synthetic fuel production installations*

In the *CLI* scenario, negative emission technologies based on BECCS are deployed in the energy conversion sectors for the production of electricity, hydrogen and biogenic gases and liquids. DACCS is deployed mostly after the deployment of BECCS. Its role in delivering negative emissions may increase in the years after 2050, to maintain the overall CO_2 budget within the limit needed for achieving the Paris Agreement goals, if BECCS cannot be further scaled up due to limited domestic biomass resources. In the *CLI* scenario, the total CO_2 emissions captured are about 8.6 Mt CO_2/yr. in 2050, of which about 4 Mt CO_2/yr., or about the half of the total captured emissions, are considered as negative emissions, i.e. are captured by BECCS and DACCS. BECCS for hydrogen production accounts for about 40% of the negative emissions. About one-third of the negative emissions are from waste incineration plants with CCS, referring to the renewable part of the waste (50% of the total waste used). BECCS for biofuel production (syngas) and DACCS capture altogether another 0.3 $MtCO_2$/yr. in 2050.

In terms of average CO_2 emissions per capita, the *EPOL* scenario achieves about 1.3 t CO_2 in 2050, which is compatible with the already communicated target for 2050 in UNFCCC in 2017[1] , before its revision in 2020 that includes the Paris Agreement pledges [2]. In this regard, the trajectory of the *EPOL* scenario can be considered that is on a track of the climate target of a maximum 2^{o}C increase in the global average temperature compared to the pre-industrial levels by the end of the century.

[1] See https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Switzerland%20First/15%2002%2027_INDC%20Contribution%20of%20Switzerland.pdf

[2] See https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Switzerland%20First/Switzerland_Full%20NDC%20Communication%202021-2030%20incl%20ICTU.pdf

7.1.1 Industry

The results for industry reveal a decline of the CO_2 emissions from fuel combustion and industrial processes in all the three scenarios. In the *BAU* scenario, the emissions reductions follow the current trends in energy consumption and structure of the industrial activity. In the *EPOL* scenario, the emissions reductions are driven by the overarching energy efficiency targets, as well as by the linear emission reduction factor of the ETS. In *CLI*, the stringent climate policy to meet the net-zero emissions in 2050 drives a further reduction in emissions compared to *EPOL*. As industrial processes are relying on gas, there is still CO_2 emitted in industry in both *EPOL* and *CLI* scenarios (see figure 7.2). Carbon capture in industry mainly occurs in CHP waste plants, in large-scale industrial natural gas CHP plants, and in plants connected to industrial processes, e.g., for cement production.

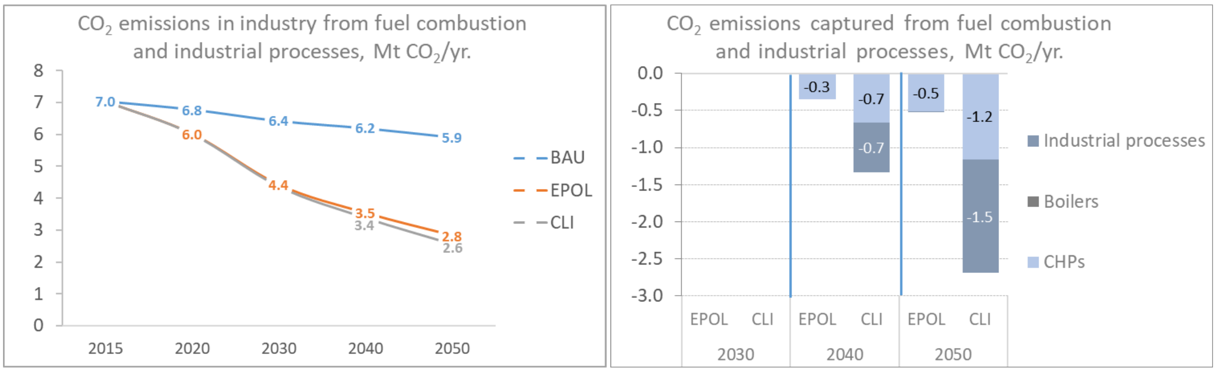


Figure 7.2: *Left: CO_2 emissions from fuel combustion and energy processes in industry after capture, including on-site cogeneration. Right: CO_2 emissions captured in industry by source*

Figure 7.3 shows the decomposition of the CO_2 emissions in *EPOL* and *CLI* scenarios, by major source. Even though the two scenarios deliver a similar range of emissions reductions, in *EPOL* this is mainly due to the reduction of fossil fuel combustion in boilers and on-site CHP plants. In contrast, emissions from industrial processes remain a significant part of the overall emissions in industry in 2050 — if not fundamental changes in the production processes' structure are assumed.

In *CLI*, the reduction in emissions is achieved with CCS in industrial processes and with the decarbonisation of the industrial heat. Because cogeneration in *CLI* increases over time (see also section 3.2), there is a smaller decrease in the emissions from CHP plants in *CLI* compared to *EPOL*. The large CHP plants in *CLI* are equipped with carbon capture to further reduce the CO_2 emissions in industry.

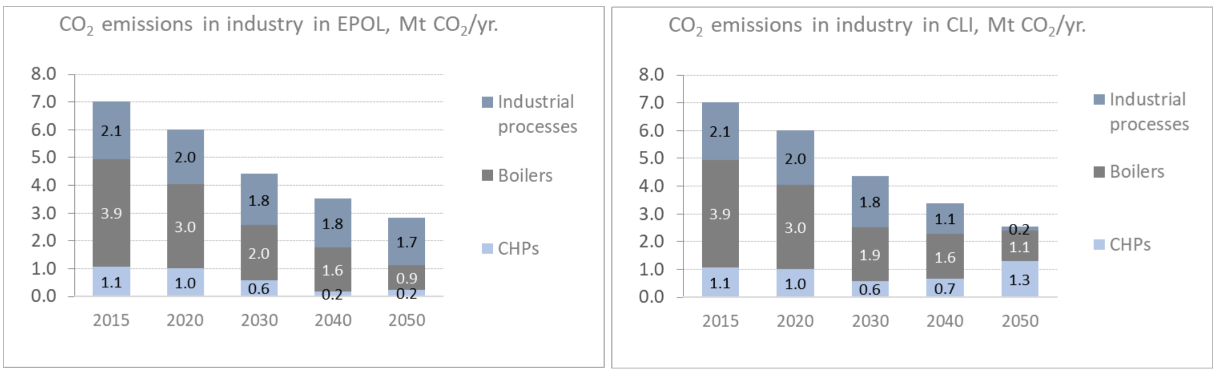


Figure 7.3: *Decomposition of the CO_2 emissions in industry by source in the EPOL (left) and CLI (right)*

7.1.2 Services

As shown in figure 7.4, in services, commercial and agriculture sectors, the CO_2 emissions decline in all scenarios in 2050 from the levels of 2015. The drivers of the reduction in emissions are different among the scenarios. In *BAU*, the lower carbon intensity of the sector is attributable to the continuation of current trends in demand and technological progress. In the *EPOL* scenario, the main factor pushing decarbonisation is the enforcement of stringent efficiency targets that leads to a switch in heat pumps and implementation of renovation and energy conservation measures. In the *CLI* scenario, the stringent climate change mitigation policy enables a more radical reduction in emissions compared to the rest of the two scenarios.

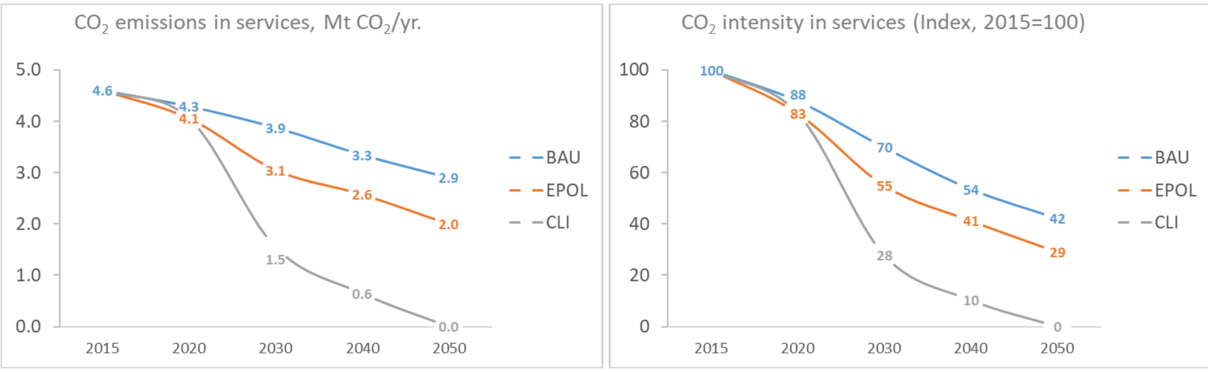


Figure 7.4: *CO_2 emissions in services and agriculture (left), and CO_2 intensity in terms of a unit of CO_2 emitted per unit of economic output (right)*

In this regard, the *CLI* scenario goes beyond the emissions standards foreseen in the revised CO_2 Act (SFOEN, 2020b), even from 2030. For instance, the average amount of CO_2 emitted per square meter in *CLI* scenario is about 8.5 kg CO_2/sqm in 2030 and 3.3 kg CO_2/sqm in 2040. For comparison, in *EPOL* scenario, the average specific CO_2 emissions per square meter are 16.8 kg in 2030, 13.4 kg in 2040, and about 10.0 kg in 2050. This result suggests that *EPOL* lags almost two decades in the emission reduction effort in the services sector, compared to *CLI*. The *BAU* scenario constantly remains above 14 kg CO_2 per square meter until 2050. When the trajectory of *BAU* is compared to *CLI*, then the *BAU* scenario is about two decades behind *CLI* in the mitigation effort.

The above outcome indicates the pace of transformation that the services sector need to achieve, so that the Swiss energy system, as a whole, reaches net-zero emissions by 2050. The critical decade in delivering the required emission reductions is between 2020 and 2030, in order to avoid lock-in carbon-intensive infrastructure. The transformation of the sector towards low-carbon energy consumption relies on a large roll-out of heat pumps in the next decade, accompanied by an accelerated renovation in the last two decades.

The overall carbon intensity of the services sectors, in terms of a unit of emissions emitted per unit of economic output produced, declines over time, as shown in figure 7.4. While in *BAU* and *EPOL* scenarios the improvement in carbon intensity is almost linear over time (i.e. at a constant rate), in the *CLI* scenario it is exponential, underpinning the effort which is needed already in the first decade starting from today.

7.1.3 Residential

The residential sector is moving towards less carbon-intensive space and water heating, even in the *BAU* scenario (see figure 7.5). The replacement of ageing equipment with more efficient one, as well as the demolition of existing buildings and the construction of new ones based on increasingly stringent building energy and efficiency standards over time (see also section 2.4), reduce the emissions in the *BAU* scenario by 4 Mt CO_2 between 2050 and 2020. In *EPOL*, the implementation of energy efficiency targets delivers 1 Mt CO_2 additional reduction in 2050, from the levels of *BAU*. Achieving the net-zero emissions ambition in the *CLI* scenario would require full decarbonisation of the residential sector by 2050.

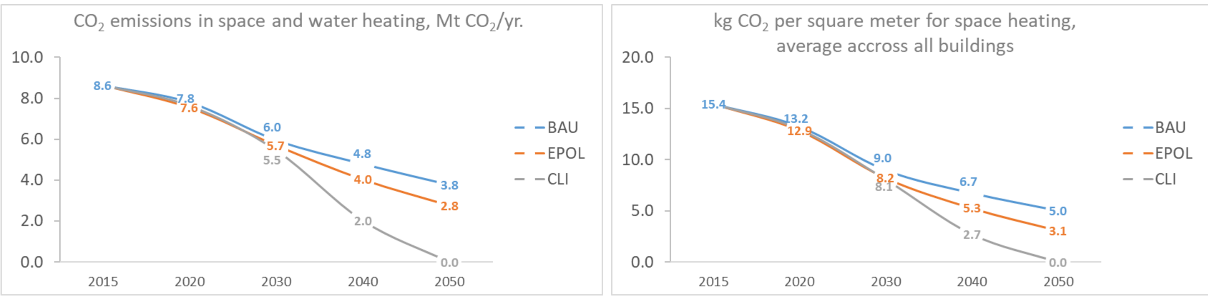


Figure 7.5: *CO_2 emissions for space and water heating, and average kg CO_2 per square meter*

If the residential buildings are to be fully decarbonised towards 2050, this would require that the average CO_2 emissions per square meter drop by more than one-third in 2030 from 2015 (figure 7.6). In existing buildings, the CO_2 emissions per square meter reach 13 kg in 2030 and 5 kg in 2040, before they go to zero in 2050. New buildings need to be near-to-zero emissions even by 2030 to facilitate the decarbonisation of the sector in 2050 and avoid carbon-intensive lock-in effects in heating (not only oil-based heating but also natural gas boilers and heat pumps as well).

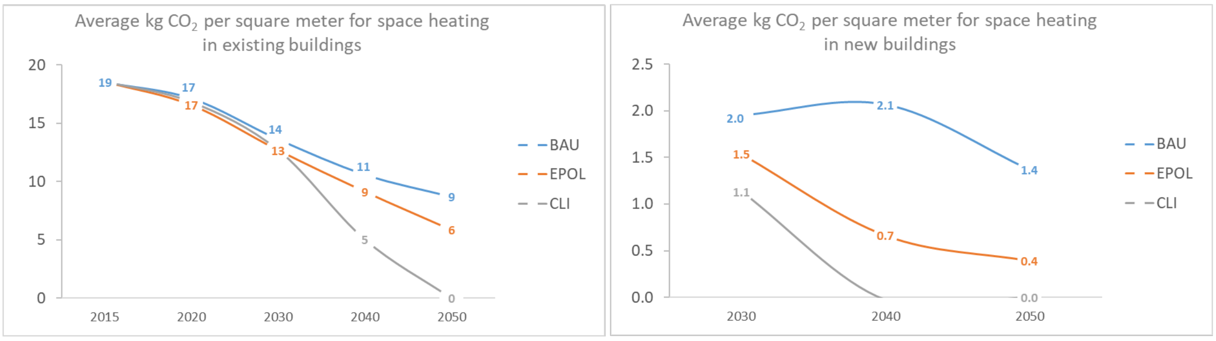


Figure 7.6: *CO_2 emissions for space and water heating, and average kg CO_2 per square meter*

The emissions reduction trajectories shown in figure 7.6 can be considered as very steep. If these trajectories are not achieved, and there are still remaining emissions in the residential buildings by 2050, then these emissions will require additional reductions in the other sectors of the energy system in order to offset them, mainly in industry and conversion sectors that both can deploy CCS and DACCS options. Such an increased development of CCS imposes the challenge of storing the captured carbon dioxide within the Swiss territory, and, in the case that this limited, access to international CO_2 storage sites will be required, or the implementation of CCS projects abroad will be necessary to offset emissions, also in accordance with the Article 6 of the Paris Agreement.

7.1.4 Transport

In the transport sector, the increased competitiveness of electric vehicles induces a shift to low- and zero-emission drivetrains, already in the *BAU* scenario (figure 7.7). Hence, in the long-term, the emissions from the mobility sector are projected to significantly decline from their existing levels, despite the growth of the demand and the expansion of the vehicle stock. Following these trends, in the *BAU* scenario the emissions from transport decline by more than 50% in 2050 from 2015. The implementation of vehicle emissions standards in the *EPOL* scenario induces an additional reduction of roughly 4.4 Mt CO_2 in 2050 compared to the levels seen in *BAU*. Achieving the net-zero emissions ambition by 2050 (*CLI* scenario) would imply that the transport sector is decarbonised by then. The residual emissions shown in figure 7.7 are from direct combustion of synthetic Power-to-Liquids (PtL) from renewable sources, for which their carbon content has been offset in their production via carbon capture and storage.

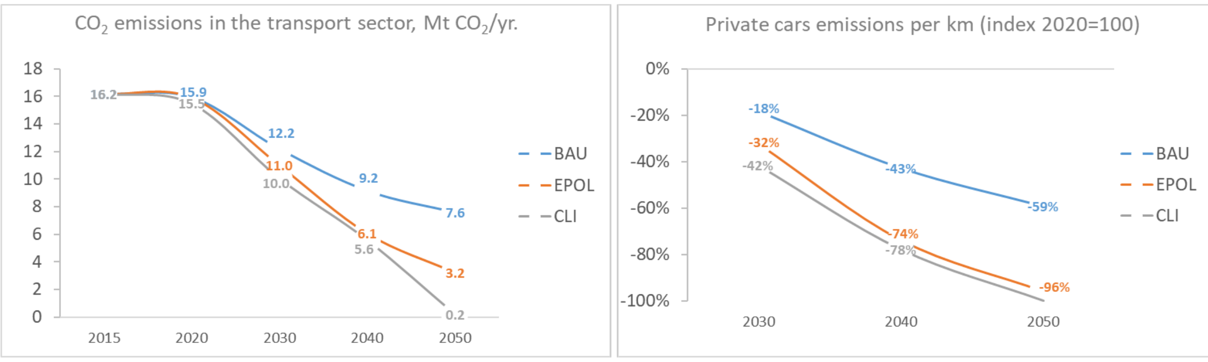


Figure 7.7: *CO_2 emissions in the transport sector, excluding international aviation (left), and average specific emissions per km for private cars (right). In both charts, it is assumed zero direct emissions from biofuels as well as imported e-fuels from renewable electricity sources. The direct emissions from the combustion of domestically produced synthetic e-fuels are accounted in this figure, and they are offset when accounting for the emissions in the energy conversion sector*

The largest transformation in the mobility sector is seen in the private cars sector. As shown in figure 7.7, the specific emissions per km travelled decline by almost 60% in the *BAU* scenario in 2050 compared to 2020 levels, while in the *EPOL* scenario decline by 97% over the same period. In the *CLI* scenario, the specific emissions per km in 2050 are near zero.

In the *EPOL* scenario, the emissions standards for the new vehicle registrations are the main pillars for the developments in the private cars sector throughout the whole projection period. The model results show that the specific emissions per kilometre from new cars in *EPOL* never go beyond the imposed emissions targets, as deeper emission reductions are not on the focus in this scenario. However, in the *CLI* scenario, the vehicle emissions standards drive the decarbonisation of the transport sector mainly until 2040. In the last decade, the overarching ambition to achieve net-zero emissions in 2050 accelerates the penetration of zero-carbon vehicles, not only in the private cars sector but also in the rest of the road transport sectors as well. In this regard, the average specific emissions per kilometre for new vehicles go below the imposed emissions standards.

7.1.5 Electricity production

The power sector in Switzerland faces the challenge to maintain the almost carbon-free electricity production after the phase-out of the nuclear power plants and at the same time provide secure and reliable electricity to the Swiss consumers. Whether or not the power sector avoids a carbon-intensive production largely depends on the developments in the demand side and on the climate policy ambitions.

In the *BAU* scenario, the absence of clear and long-term carbon pricing signals results in significantly higher emissions in the power generation in 2050 than in 2015. In the *EPOL* scenario, the renewable targets, as well as the strong efficiency measures to reduce the electricity consumption, support a trajectory that leads to about a 40% reduction in the emissions from electricity generation in 2050 compared to 2015 levels. Achieving the net-zero emissions in the Swiss energy system in 2050 in the *CLI* scenario would require that the electricity sector is fully decarbonised and reaches net negative direct emissions by then (figure 7.8). The achievement of net-zero emissions in electricity generation would require the implementation of CCS in waste treatment and large wood-fired power and heat plants.

It should be noted that the emissions from on-site CHP plants in industry, services and residential sectors are considered in the end-use sectors. As emissions for electricity production we include emissions from medium-to-upper grid levels fossil plants for district heating and electricity.

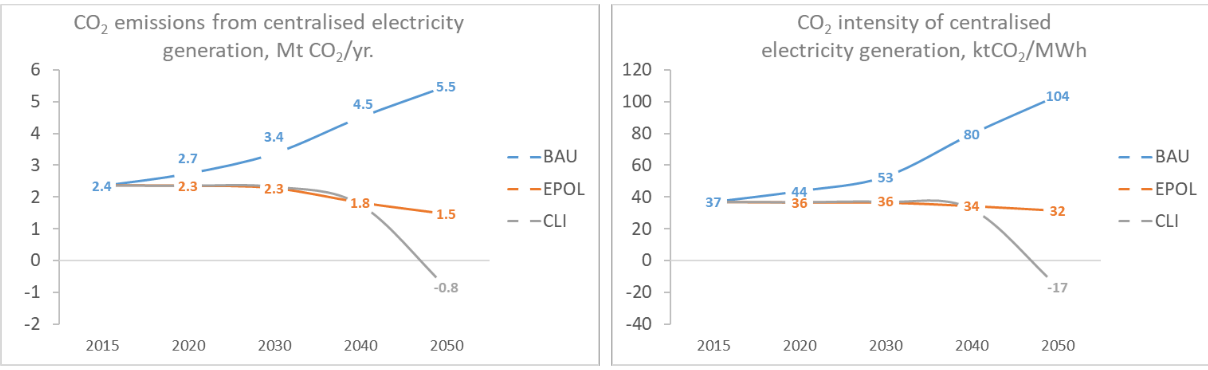


Figure 7.8: *CO_2 emissions in the electricity sector, excluding emissions from fuel combustion in on-site CHP plants in industrial, commercial and residential sectors (left), and carbon intensity of the electricity production (right)*

Following the above developments, the carbon intensity of the electricity production triples in the *BAU* scenario in 2050 compared to 2015 levels, as large scale gas-based generation penetrates in the electricity supply. In *EPOL* and *CLI* scenarios, the carbon intensity is following a similar trajectory in both scenarios until 2040. In the decade from 2040 to 2050, it becomes negative in the *CLI* scenario, while it remains stable in the *EPOL* scenario.

7.1.6 Hydrogen production

The hydrogen production sector in Switzerland has three main technology pillars that influence its carbon intensity: electrolysis, gas reforming and biomass gasification. Depending on the level of the ambition, the hydrogen sector can remain carbon-intensive (as in the *EPOL* scenario) or switch to biomass and deliver negative emissions to the Swiss energy system (as in the *CLI* scenario).

As shown in figure 7.9, the hydrogen sector in the *CLI* scenario offsets about 1.5 Mt CO_2 by 2050 that are residual emissions mainly from industrial activities in 2050. This is achieved with carbon capture in gas reforming facilities and the deployment of wood gasification with CCS (BECCS) to deliver negative emissions.

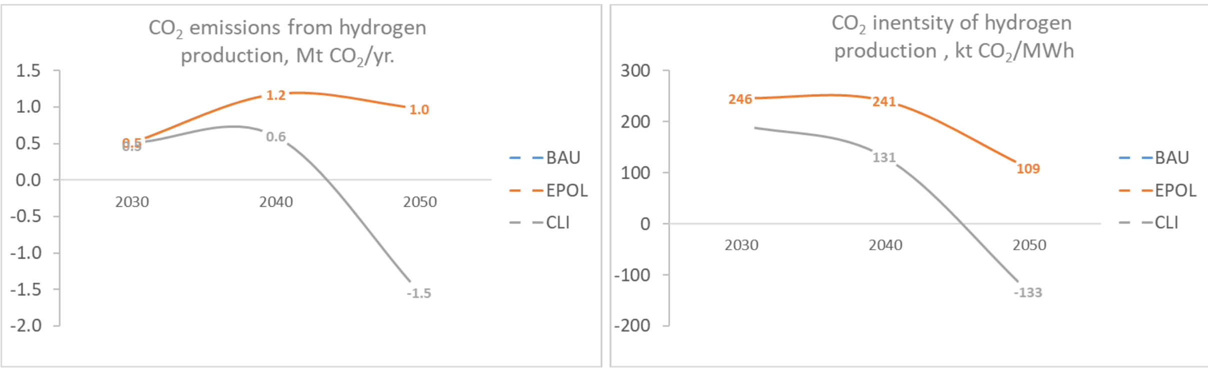


Figure 7.9: *CO_2 emissions in hydrogen production (left) and carbon intensity of the hydrogen production (right)*

7.1.7 Biofuels production

Together with the hydrogen production sector, also the production of domestic biofuels with carbon capture delivers negative emissions to the Swiss energy system. In the *CLI* scenario, there is about 4.3 PJ of biomethane produced by using wood gasification and carbon dioxide removal during the cleaning of the produced syngas (ZEP, 2012) that results in about 0.2 Mt CO_2/yr. negative emissions from this conversion route in 2050.

7.1.8 Direct Air Capture

Direct air capture and storage (DACCS) offsets emissions which are dispersed, such as in the transport sector. It has the advantage of occupying significant less land than BECCS for the same amount of carbon removals, which can be in the order of 1000 times less (e.g. for capturing 100 Mt CO_2 annually BECCS requires 3 to 6 million hectares, while DACCS 4 to 15 thousand hectares). However, DACCS does not deliver energy with carbon removals. On the contrary, it requires significant amounts of energy. In *CLI* scenario DACCS offsets about 0.1 Mt CO_2/yr. in 2050. To capture CO_2 through DACCS technologies, energy input is needed. The overhead in the electricity and heat consumption induced by the operation of DACCS for removing 0.1 Mt CO_2 in 2050 is about 0.6 PJ heat and 0.08 PJ electricity, which is equivalent to the consumption of about 18,000 households in 2050.

7.2 CO_2 storage and utilisation pathways

Achieving net-zero emissions by 2050 requires the deployment of carbon capture to offset emissions from the energy system that cannot be abated otherwise. These include emissions from industrial activities, waste, as well as any remaining emissions from the transport sectors that are hard to be fully decarbonised. In total, from the energy system perspective only and by excluding international aviation, the amount of the CO_2 that needs to be captured is about 8.6 Mt CO_2/yr. in 2050 (figure 7.10). If the energy system is also supposed to offset emissions from agriculture, and if the emissions from agriculture are at least 5 Mt CO_2-eq in 2050 according to (Swiss Federal Office for the Environment, 2020), then more than 12 Mt CO_2/yr. would be needed to be captured by the energy system and removed from the atmosphere[3].

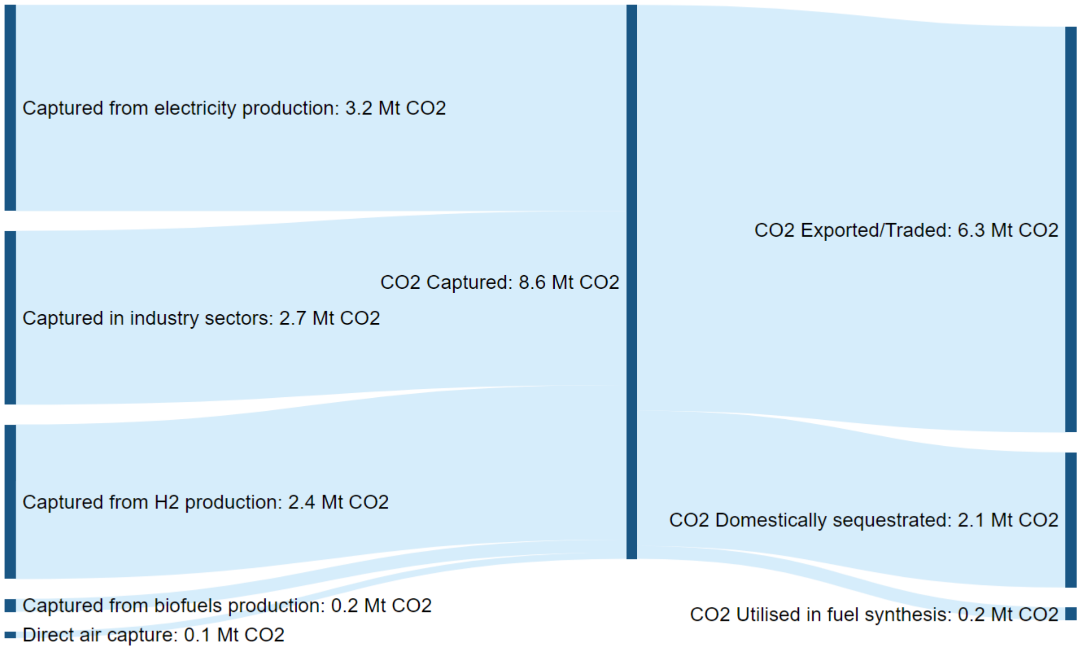


Figure 7.10: *CO_2 emissions captured by source, exported, sequestrated and utilised in the production of the synthetic fuels*

The amount of negative emissions is about half of the total amount of the captured CO_2 emissions in 2050. Beyond 2050, the uptake of negative emission technologies is expected to increase. For instance, the IPCC SR1.5 Report estimates that the global remaining CO_2 budget to restrict the temperature increase below 1.5^{o}C by the end of the century with 66% probability is about 420 Gt CO_2 from 2018 (Masson-Delmotte et al., 2018). By adopting an egalitarian approach across the global population, the remaining Swiss budget is about 420 Mt CO_2 if we assume 10 billion people globally in 2100 and 10 million people in Switzerland. In *CLI*, the cumulative emissions from 2020 to 2050 are about 620 Mt CO_2 which implies that by 2050 there will be a deficit of about 240 Mt CO_2 that is needed to be offset by increased deployment of negative emission technologies to comply with the 1.5^{o}C climate target or which needs to be abated abroad[4]. It follows that emissions reduction trajectories that assume a more delayed action compared to *CLI* trajectory would require even higher reliance on negative emissions technologies after 2050.

Therefore while effective measures to reduce CO_2 emissions are essential to a successful climate policy, the speed of implementation of CC(U)S technologies, and negative emission technologies in particular, is crucial to meet ambitious climate goals. In this regard, an early embedding of carbon dioxide removal approaches, including negative emission technologies, is required in the Swiss climate policy, in order to provide stable long-term signals to investors and stakeholders. The trajectory fol-

[3]STEM in an energy systems model. Including emissions from the non-energy sectors in the assessment requires interfaces with models for agriculture and forestry, which is not in the scope of the SCCER JASM project.

[4]E.g. through crediting foreign emission reductions under Article 6 of the Paris Agreement.

lowed to achieve the net-zero ambition defines the level of the reliance on negative emission technologies in the post-2050 period, as delayed actions can lead to their significant deployment (Rogelj et al., 2019). Key among such signals is adequate CO_2 pricing, coordination with agricultural, energy, spatial planning and transport policy, as well as crediting the negative emission technologies as compensation measures to advance scaling to a marketable size.

CO_2 storage in Switzerland is a challenge, and a connection with other potential European networks is a key requirement if domestic sequestration is of limited potential or not an option at all. According to our scenario assumptions and model results, more than three-quarters of the captured energy and process-related CO_2 emissions need to be exported in the *CLI* scenario, as the domestic sequestration potential is still uncertain for structures suitable for storing large amounts of CO_2 for several years. Following (Diamond et al., 2019), we limit the domestic sequestration potential to around 50 Mt CO_2. CO_2 utilisation pathways via fuel synthesis cannot help in the long term deliver negative emissions needed to achieve the net-zero targets, because they entail the risk that energy demand is still locked-in carbon-intensive infrastructure.

Given the above, Switzerland would eventually rely on transport infrastructure across the EU, and it would need to have access to storage hubs, e.g. in Norway, such as the Northern Lights Project. In this regard, international agreements and participation in projects of common interest that deal with cross border CO_2 storage infrastructure development need to be ensured (also in-line with Article 6 of the Paris Agreement). Not having the option of capturing and storing CO_2 in- and outside Switzerland would have significant implications on the achievement of ambitious Swiss climate goals and the associated costs (see also section 9).

7.3 Transition enablers, opportunities and challenges

Besides many other CO_2 emission reduction measures and CC(U)S connected to waste incineration and industrial processes, the net-zero ambition requires the deployment of negative emission technologies to offset the remaining emissions that are most difficult to abate in transport, in industry and from waste management. Maintaining, or even increasing, the LULUCF sink is essential but might not be sufficient and will itself depend on other developments, for instance, related to changing dietary consumer preferences (Smith et al., 2015). In this respect, carbon dioxide removal technologies should not be disregarded as part of the solution, and at its meeting on 2 September 2020, the Swiss Federal Council approved a report on the importance of negative CO_2 emissions for Switzerland's climate policy[5].

Although all components of the carbon dioxide capture and storage technology are known, and carbon dioxide removal projects have been deployed at an advanced demonstration scale worldwide[6], there are financial barriers related to the cost of capture and storage and social acceptance barriers for onshore domestic storage due to concerns about the integrity of storage facilities and the perceived risk of CO_2 leakage. A better understanding of the impact and potential of NETs is needed among policy makers, research, industry and society. Promising NETs should be further developed and explored, without excluding alternatives from the list of options.

[5] See https://www.newsd.admin.ch/newsd/message/attachments/62703.pdf

[6] See for example https://co2re.co/FacilityData

In Europe, there is a discussion to mitigate these barriers, by planning the offshore storage of CO_2 as below seabed storage, where public acceptance concerns are less of an issue, and by also allowing the capture of CO_2 and its storage to take place at different sites and possibly different countries (EC, 2018). Offshore CO_2 storage has been demonstrated for more than a decade in the Norwegian Sleipner field, and the Northern Lights project implemented by Norway aims at this direction[7]. However, such a cross-border transmission and storage of CO_2 would require to scale up the necessary infrastructure and also to the set-up of a consistent framework to account correctly for emission removals.

If storing carbon dioxide in the Swiss territory is uncertain or limited, then the above options constitute a possible solution: a plant with carbon capture is operating in Switzerland, but the CO_2 emitted is transferred to another European country with offshore storage capacities. However, to realise this option, Switzerland would need to obtain access to those infrastructures soon enough, either through its involvement in co-developing this infrastructure or by establishing international agreements for delivery contracts. At the same time, Switzerland would need to actively participate in establishing the regulatory framework that would enable cross-border transactions of carbon dioxide. A failure in the scaling up of the carbon capture technology in Switzerland due to financial, social acceptance, or storing limitations, would endanger the achievement of the net-zero emissions target and increase the cost of mitigation.

[7] See https://northernlightsccs.com/en/about

Chapter 8

Insights from the assessed variants

Besides the *CLI* core scenario achieving the net-zero emissions ambition by 2050, we have also quantified a number of variants to investigate different aspects along the axes of the energy trilemma, as shown in figure 2.3. Based on the *CLI* scenario, the variants are built gradually, one on the top of the other, by step-wise lifting constraints and introducing new enablers for facilitating the energy transition, as shown in table 8.1. As such, the variants ensure comparability to the core *CLI* scenario, and to some extent among themselves. This chapter highlights the major dynamics of the energy system observed in the variants and focuses on presenting the results of on main indicators.

Table 8.1: *Overview of the assessed variants concerning key constraints and transition enablers*

Name	Limited remaining exploitable sustainable renewable energy potential	Limits on import dependency and in particular in electricity and zero-carbon fuels	Enabling global and local energy markets integration	Increased innovation leading to lower technology costs	No electricity consumption target constraint in EPOL	No sectoral emissions reduction targets beyond 2030	Not achieving net-zero: 80% reduction in CO_2 emissions in 2050
ANTI	X	X					
SECUR		X					
MARKETS			X				
INNOV			X	X			
EPOL-E					X		
CLI100						X	
CLI80						X	X

Each one of the variants tries to provide insights into the following key questions:

- What if the foreseen levels of renewable expansion cannot be realised, and at the same time, if there is limited availability of zero-carbon energy carriers imported from other world regions? How does the emissions mitigation pathway look like in such a case, and which sectoral targets are not met during the transition? (variant *ANTI*)
- Can Switzerland achieve the net-zero ambition by mostly relying on domestic resources, if these resources can be exploited to their maximum technical potential? How does the cost of such a mitigation pathway compare to other alternatives, and what does this mean for energy security? (variant *SECUR*)

- What is the impact on the cost of the transition, if an increased integration between Swiss and global energy markets is achieved? What does this mean for the domestic solutions? (variant *MARKETS*)
- How the speed of the transition, as well as its cost, is affected when a higher level of innovation is achieved worldwide related to the improvement of low-carbon technologies? (variant *INNOV*)
- What if in the Swiss Energy Strategy the indicative target of reducing the average per capita electricity consumption is not implemented? (variant *EPOL-E*)
- What is the impact of enforcing emissions standards for vehicles and buildings, as well as other sectoral targets such as ETS, regarding the cost of the mitigation pathway as well as the technology deployment (and possible infrastructure lock-in)? (variant *CLI100*)
- What is the additional effort required to go from the Cancun Agreements in 2010 of holding the increase in global average temperature below 2^{o}C to the Paris Agreements in 2015 of limiting the global warming well below 2^{o}C by the end of the century compared to the pre-industrial levels? (variant *CLI80*)

Therefore, the variants have been designed around the following main dimensions of the energy transition. The *climate change mitigation* dimension that addresses the level of ambition, the *market integration* dimension that refers to the levels of cooperation of regional, national and international markets, the dimension of *the speed of innovation* that explores the effects of technology performance of emerging technologies in achieving the targets of the energy and climate policies, the dimension of *technology acceptance* that relates to social aspects surrounding the deployment of certain technologies (e.g. CCS), and the dimension of *resource availability* that addresses accessibility to domestic renewable resources.

8.1 Achieving net-zero under low availability of low-carbon domestic and imported resources: variant *ANTI*

The main storyline of the *ANTI* variant is built around fragmented climate change mitigation policies worldwide, which are assumed to result in a stagnation of R&D expenditures in low-carbon technologies, and, consequently, a failure to achieve the promising improvements in the performance of these technologies. Thus, there are higher upfront capital costs for consumers and utilities that ultimately hinder renewable energy expansion. The fragmented global policies constitute an investment environment that does not support the exploitation of the remaining renewable energy potentials to the maximum, as clear long-term price signals are not given to investors. Also, in the context of low international cooperation, the integration between the Swiss and European energy markets is weak, affecting the availability of low-cost imported zero-carbon energy carriers.

ANTI assumes higher investment costs for low-carbon supply and demand technologies, as well as it sets the potentials for bioenergy, wind, solar and geothermal energy to low values (e.g. use of wood for energy is limited slightly above its current levels). The availability of imported biofuels and synthetic fuels, as well as low-cost electricity, is limited as much as possible to achieve the net-zero target, under limited domestic resources. The variant is built around the pessimistic assumptions regarding technology costs, resource potentials and import prices, as these described in (Bauer et al., 2017, Guidati et al., 2020, Marcucci et al., 2020).

8.1.1 Final energy consumption

The low availability of imported zero-carbon energy carriers and the low domestic renewable energy resources limit the decarbonisation options in the end-use sectors. Fuel switching to cleaner energy technologies cannot deliver the emissions reduction attained in *CLI* in the stationary sectors, due to resource scarcity. The stationary sectors, and in particular, the residential and industrial sectors, implement additional renovation and energy conservation measures to reduce energy consumption and, consequently, emissions. Moreover, the energy conservation measures are deployed not only at a larger scale than *CLI*, but also almost a decade earlier.

As a result of the above developments, the total final energy consumption in *ANTI* is much lower than in *CLI* throughout the projection period (figure 8.1). The residential sector drives the energy demand reductions, followed by industry to a lesser extent. In contrast, the services and transport sectors reach similar consumption levels in *ANTI* as in *CLI*.

The fuel mix in the end-use sectors is characterised by lower electricity consumption over the whole period to 2050, compared to the *CLI* scenario. As stated above, this is attributable to the scarcity of renewable resources for electricity production and the limited electricity imports. Notwithstanding the lower electricity consumption in absolute terms, the electrification of the demand remains at the levels seen in the *CLI* scenario since the reduction in the overall final energy consumption in *ANTI* surpasses the reduction in electricity, due to the larger (and accelerated) deployment of energy conservation. The consumption of hydrogen in *ANTI* is also lower than *CLI* because the supply of hydrogen in a context of net-zero emissions depends on the availability of imports, excess electricity and bioenergy. All these three options are not available in *ANTI*, at least in the levels seen in *CLI*.

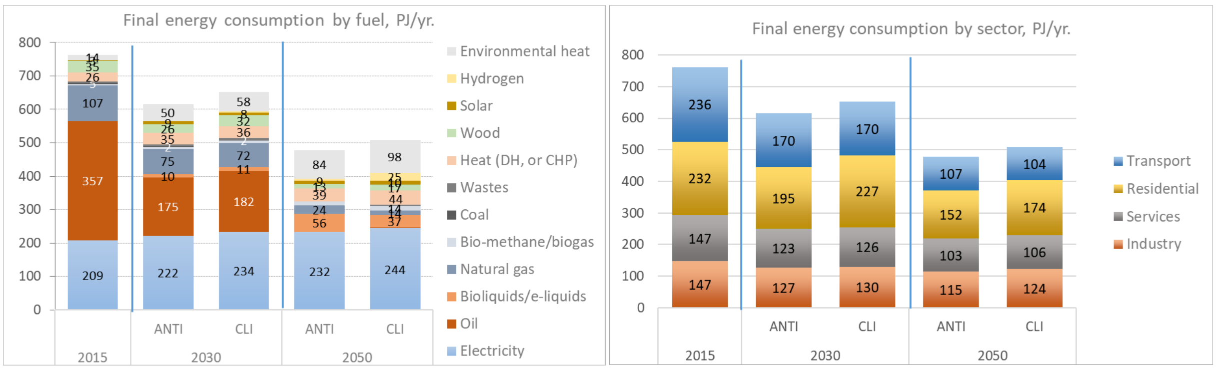


Figure 8.1: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

As shown in figure 8.2, the electricity consumption in the transport sector is sustained to the levels of *CLI*, in contrast to the developments in the stationary sectors. Driven by the limited availability of decarbonisation options for the long-distance transport, as well as the market segment of large size private cars, mobility undergoes a transformation towards electric drivetrains backed up by imported biofuels/synthetic e-fuels, at a slightly accelerated pace than in *CLI*. For instance, in *ANTI*, the segment of the large-size private cars stays at the conventional hybrid technology in 2050. These hybrids are fuelled by imported biofuels/e-fuels, instead of shifting to hydrogen as it is the case in *CLI*.

However, the coordinated action in end-use sectors that guarantees the availability of electricity and imported biofuels/e-fuels in those mobility sectors with limited decarbonisation options is, however, associated with high costs (see section 9.3) that arise from the choice of the most expensive option to decarbonise the long-distance transport and large-size private cars and from the deployment of energy conservation measures in the stationary sectors.

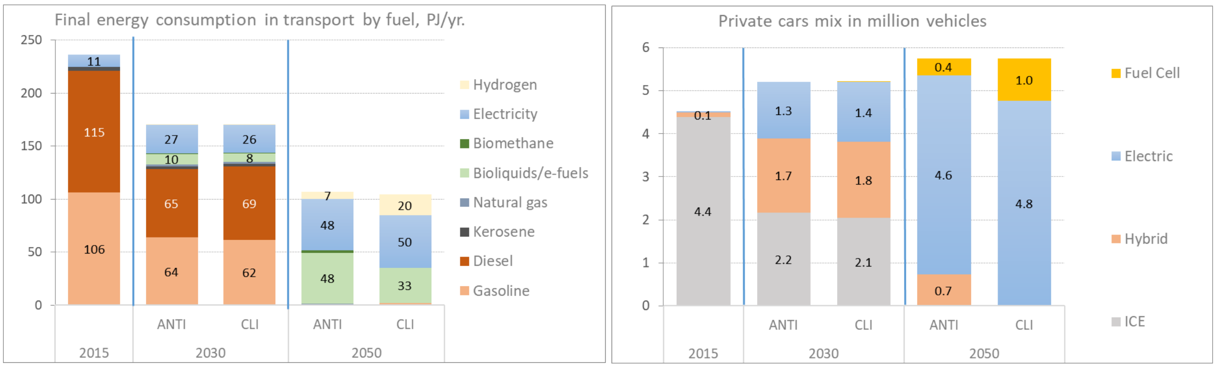


Figure 8.2: *Fuel consumption in the transport sector (left) and private cars fleet (right). In the chart, and also in the similar ones in this section, Plugin Electric Hybrid Vehicles are accounted as Electric as well, while the category Hybrid includes only the conventional hybrids*

8.1.2 Hydrogen production and consumption

As already indicated above, the hydrogen penetration in the Swiss energy system in the *ANTI* variant is much lower than in *CLI*. As shown in the left panel in figure 8.3, under the conditions of *ANTI*, hydrogen is primarily produced via wood gasification with CCS to be able to deliver also negative emissions to the energy system to relief the mitigation pressure of other sectors. This outcome suggests that the uptake of SMR/ATR and electrolysis is mainly enabled to meet the residual demand for hydrogem, after deploying wood gasification with CCS if this option is available.

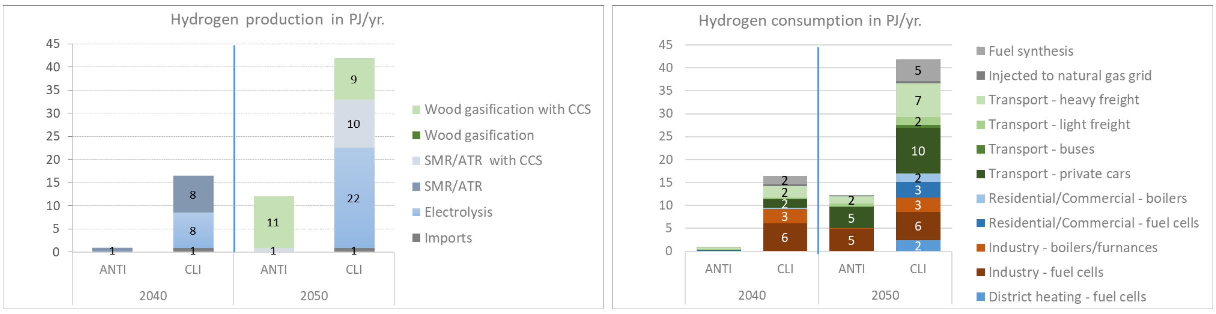


Figure 8.3: *Hydrogen production by technology (left) and hydrogen consumption by sector (right)*

As shown in the right panel of figure 8.3, hydrogen is mainly consumed in industry and mobility sectors. This implies that, under restricted resources to decarbonise energy demand, hydrogen use is prioritised to the sectors with the most limited decarbonisation options or those applications that need gaseous fuels.

As a result of the low deployment of electrolysis in *ANTI*, the role of hydrogen in sector coupling and the deployment of Power-to-X options is more limited compared to *CLI*. In this context, there is no production of synthetic fuels from domestically produced hydrogen or electricity generation from fuel cells in services, residential and in district heating, to enable hydrogen as cost-effective and efficient energy carrier in the end-use sectors.

8.1.3 Electricity production and consumption

The electricity supply in the *ANTI* variant plateaus after 2030 due to the strong deployment of efficiency measures in the stationary sectors. As in the *CLI* scenario, also in *ANTI*, the electricity sector undergoes a transformation towards new renewable energy sources (figure 8.4).

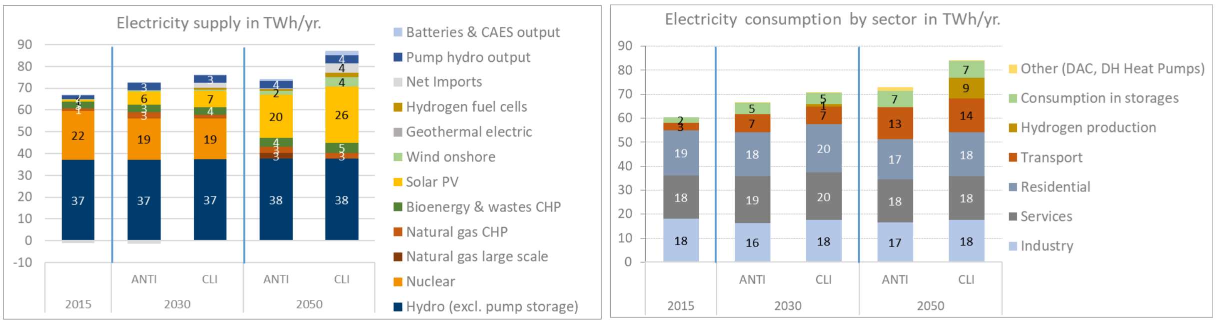


Figure 8.4: *Electricity production by technology (left) and consumption by sector (right)*

However, the penetration of wind and solar photovoltaics in the *ANTI* variant is much lower than in *CLI*, resulting from the less optimistic assumptions for renewable potentials and technology performance. Also, consistent with the assumptions related to the limited cross-border trade of energy carriers, the electricity imports are almost net-zero throughout the projection period. This has a significant impact on the supply mix after the nuclear phase-out, as it increases the supply-demand gap in winter. In this regard, there is a penetration of large-scale gas based-based generation with CCS, about 500 MW in 2050. Finally, the uptake of storages in *ANTI* is lower than in *CLI*, due to the lower penetration of variable renewable energy combined with the strong deployment of energy efficiency measures.

The right panel of figure 8.4 shows an overview of the electricity consumption by sector. In services it remains at the same levels as in the *CLI* scenario, indicating that most of the electricity uses in these sectors are price-inelastic. However, there is less electricity consumption in the residential and industrial sectors than in *CLI*, due to the deployment of increased renovation schemes and energy conservation measures, respectively. This coordinated action guarantees electricity availability in the transport sector, where the electrification of mobility emerges at the same levels as in the *CLI* scenario.

8.1.4 Net imports and import dependency

The level of total net imports in 2050 in the *ANTI* variant is similar with the *CLI* core scenario, as the lower imports of electricity are offset by increased imports of other zero-carbon carriers (biofuels and synthetic e-fuels needed in the mobility and stationary sectors), as well as by imports of natural gas (needed in the power generation sector) (figure 8.5).

In this regard, and given the lower overall energy consumption in *ANTI* compared to *CLI*, the index of the import dependency (measured as the ratio of total net imports to the total primary energy supply) is increased in *ANTI* when it is contrasted to the developments in the *CLI* scenario. Significantly lower levels of import dependency in *ANTI* would challenge – if not endanger – the achievement of the net-zero emissions target in 2050, particular against the background of limited exploitation of domestic sustainable resource potentials.

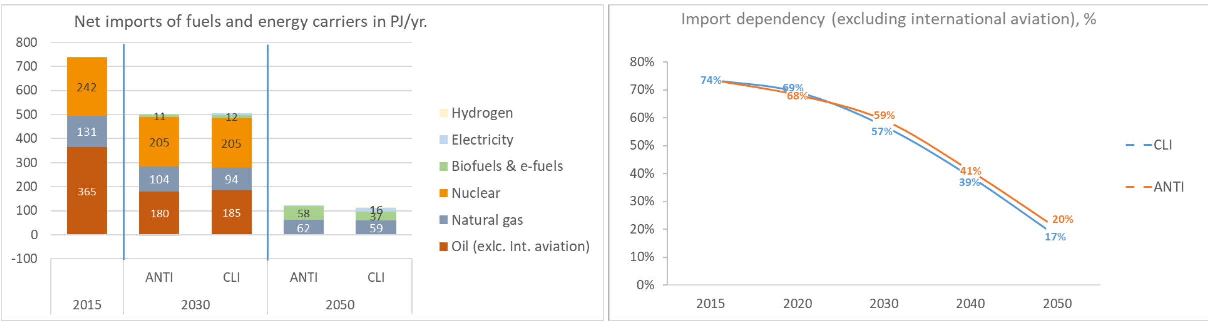


Figure 8.5: *Net imports by fuel and energy carrier (left) and overall import dependency (right). The import dependency is measured as the share of net imports to total primary energy supply*

8.1.5 CO_2 emissions and CC(U)S

The emissions reductions per sector follow the developments of the corresponding energy consumption explained above. Both services and transport sectors are fully decarbonised in this variant. However, there are residual emissions in the residential sector, which means that the standards for net-zero emissions new buildings cannot be met due to limited decarbonisation resources (figure 8.6).

Interesting insights arise when looking at the trajectory followed in *ANTI* in achieving the net-zero emissions target. As shown in (figure 8.6) the emissions from the ETS sectors (industry, energy conversion) are higher than in *CLI* scenario in 2030, which implies that the variant fails to achieve the intermediate ETS targets as the the sectors participating in ETS have limited availability of low-carbon energy carriers. However, in the long-term the conservation measures in industry that are deployed to a larger extent in this variant compared to *CLI*, result in increased emission reductions in this sector. Thus, the long-term ETS targets are met.

Similarly, in the transport sector, the the near-term vehicle emissions standards are challenged, especially in the long-distance public and freight road transport. However, as the sector is fully decarbonised by 2050, the post-2030 standards are met, as the stationary sectors deploy efficiency measures to guarantee availability of electricity to mobility.

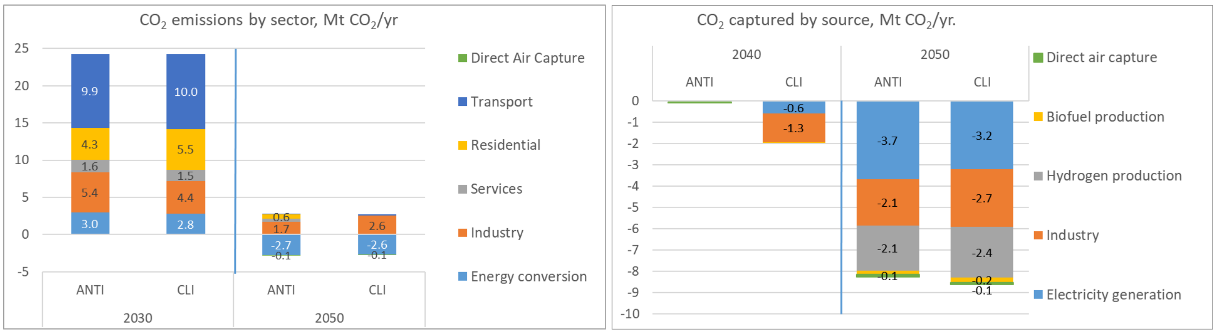


Figure 8.6: *CO_2 emissions and CO_2 captured by sector; on-site CHPs emissions are included in end-uses*

In overall the need for developing CCS and negative emissions technologies is less in *ANTI* than in the *CLI* core scenario. This is mainly because the hydrogen demand can be met without the deployment of SMR/ATR, while the additional energy conservation measures in industry reduce its carbon footprint compared to *CLI*, with the reduction in industrial emissions compensating for the residual emissions in the residential sector.

8.2 Achieving net-zero with energy security as a priority: variant *SECUR*

The *SECUR* variant puts a particular emphasis on reducing import dependency, not only for electricity but also for the rest of the energy carriers. The variant aims at achieving the net-zero ambition with the highest possible reliance on domestic means and resources. To this end, *SECUR* assumes a high social acceptance related to the exploitation of the remaining sustainable renewable potentials in the Swiss territory, and in particular for bioenergy. Given the priority to minimise import dependency, the main actors of the energy system would need to anticipate higher costs of energy to maximise energy security since relying only on domestic resources could be costlier than imports. The *SECUR* variant assumes that reinforcement of domestic infrastructure and grids is socially acceptable and desirable to increase the reliability and reduce congestion in the Swiss energy system. Compared to the *ANTI* variant, the main differences in *SECUR* are the relaxation of the renewable potentials, a more stringent import dependency target, and the further expansion of the domestic grid to relieve congestion. As in the case of *ANTI*, *SECUR* does not foresee an expansion of cross-border transmission capacities beyond the levels of *BAU*.

8.2.1 Final energy consumption

As shown in figure 8.7, the final energy consumption in *SECUR* follows *CLI* until 2030. Still, there are some distinct differences in the last two decades of the projection horizon. In *SECUR*, there is a further reduction in the final energy consumption compared to *CLI*, via the deployment of additional energy conservation measures already by 2030, to cope with the limited availability of the imported fuels and energy carriers. As a result, the total final energy consumption in *SECUR* is at the levels of *ANTI*. However, in contrast to *ANTI* where the energy consumption in transport is sustained to the levels of *CLI*, in *SECUR* also transport delivers energy reductions. As shown in figure 8.7, only the energy consumption in the services sectors in *SECUR* remain at the levels of *CLI*. The fact that both in *ANTI* and *SECUR* variants the consumption in the services sectors sustained in the levels of *CLI* indicates that the demand is largely inelastic and that there is limited potential for additional energy conservation measures in services beyond the levels of *CLI*.

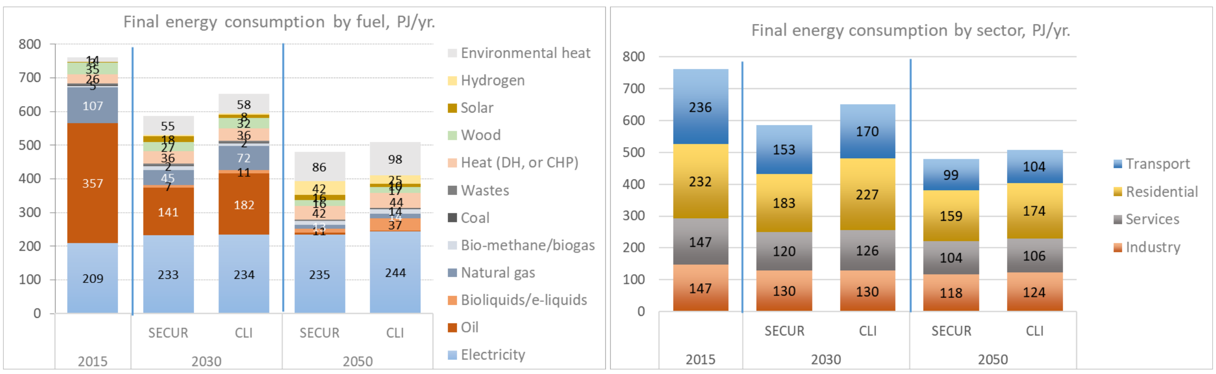


Figure 8.7: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

The fuel mix in the end-use sectors is characterised by lower consumption of electricity over the whole period to 2050, compared to the *CLI* scenario, due to the deployment of efficiency measures in residential and industrial sectors. However, the overall electrification of the demand remains at the levels seen in the *CLI* scenario. Another distinct characteristic of the energy mix in the end-use sectors in

SECUR is the higher penetration of hydrogen at the expense of imported biofuels and e-fuels. Due to the limited availability of imported zero-carbon energy carriers, domestic hydrogen production increases in *SECUR* beyond the levels attained in the *CLI* scenario, in order to fill the gap in the decarbonisation options for the transport sector (see also section 8.2.2).

Hence, the decarbonisation of the transport sector in *SECUR* is mainly based on hydrogen and electrification. The limited imports of zero-carbon biofuels and synthetic e-fuels hinder their uptake in the long-distance transport in the post-2030 period, compared to the developments in the *CLI* scenario (see figure 8.8). As a result, during the last decade of the projection horizon the penetration of fuel cell vehicles is higher in all transport modes than in *CLI*, and particularly in the long-distance public and freight transport.

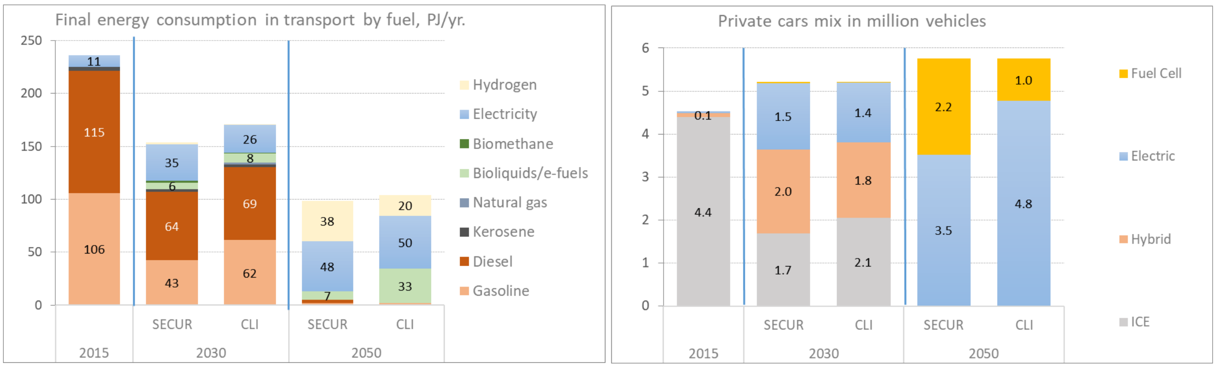


Figure 8.8: *Fuel consumption in the transport sector (left) and private cars fleet (right)*

8.2.2 Hydrogen production and consumption

Hydrogen becomes a key element in the *SECUR* variant, as it can substitute the fossil and biogenic energy carriers needed in gaseous or liquid form in the end-use sectors and in cogeneration. In *SECUR*, hydrogen is directly consumed in mobility and stationary sectors. However, the main application for hydrogen is the production of synthetic fuels, as shown in figure 8.9. About 40% of the produced hydrogen is directed to fuel synthesis. Among the synthetic fuels, gas accounts for more than 90%, with the rest being diesel and gasoline. The main use of synthetic gases is in industry and in cogeneration.

The *SECUR* variant reaches the highest levels of both hydrogen production and domestic production of synthetic fuels among all scenarios and variants assessed, and it illustrates the technical and systemic capabilities of scaling up the hydrogen production using domestic resources under the condition that these resources can be fully exploited. In *SECUR* the production of hydrogen needs to scale up very quickly, compared to the developments in the *CLI* scenario, in order to meet the increased need in zero-carbon fuels in the Swiss energy system. In this regard, *SECUR* is at least a decade ahead compared to *CLI* related to the quantities of hydrogen produced until 2040. By 2050, in *SECUR* the level of hydrogen production is twice the level reached at the *CLI* scenario.

To be able to scale up the hydrogen production, electrolysis becomes a key technology in a context of limited natural gas imports (that are needed to accelerate deployment of SMR/ATR) and domestic wood resources (that are needed to scale up gasification). As in *CLI*, wood gasification also faces competition from the rest of the sectors of the Swiss energy system in accessing the resource. However, by 2050 wood gasification remains at the levels of *CLI*, as it is a key technology for negative emissions.

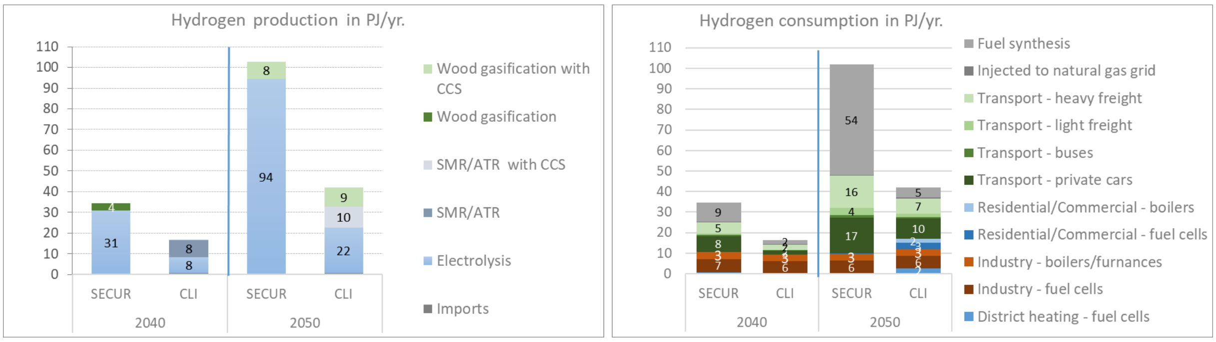


Figure 8.9: *Hydrogen production by technology (left) and consumption by sector (right)*

The electricity used in electrolysis comes from run-of-river hydropower as in the *CLI* scenario, but the large expansion seen in this variant is achieved mainly with solar PV electricity. The latter originates from large industrial facilities that also develop on-site solutions based on electrolysis to meet their needs in hydrogen and synthetic fuels. There is also deployment of solar-dedicated electrolysis. The latter delivers about one-third of the total hydrogen produced by electrolysis (or, around 10 TWh/yr. of hydrogen in 2050). While in the *CLI* scenario, the main technology used is Polymer-Electrolyte-Membrane (PEM) electrolysers, in *SECUR* high temperature electrolysis via Solid Oxide Electrolyser Cells (SOEC) penetrates too, and it becomes the dominant option in 2050 to reap efficiency gains. In this period, SOEC electrolysers alone deliver more than half of the total hydrogen in *SECUR*.

Regarding the use of hydrogen, transport has the lion's share in hydrogen consumption in the end-use sectors followed by industrial applications. However, as it is also the case in *ANTI*, there is very limited direct use of hydrogen in residential and commercial sectors compared to *CLI*. This confirms the argument in *ANTI* that under constrained supply conditions, hydrogen use is prioritised to the sectors with the fewer decarbonisation options. As in the *CLI* scenario, hydrogen also contributes to the seasonal balancing of the Swiss energy system. The seasonal shifts of hydrogen in *SECUR* exceed the ones in the *CLI* scenario, as about 2.3 TWh of hydrogen are seasonally shifted in *SECUR* in 2050 compared to 1.6 TWh in *CLI*. However, the role of hydrogen in balancing the Swiss energy system is even more pronounced in *SECUR*, when accounting the hydrogen transformed to synthetic fuels as contributions to seasonal balancing.

8.2.3 Electricity production and consumption

The electricity production in *SECUR* is characterised by an increased exploitation of the available sustainable renewable potentials (figure 8.10). Compared to *CLI*, accelerated deployment of solar electricity can be observed in *SECUR* already in 2030, by when about one-quarter of the produced electricity from solar PV systems is used in dedicated electrolysers to meet the hydrogen demand. In the post-2030 period, there is a further penetration of solar PV systems in the end-use sectors. Particularly in industry and services, the installed capacity of PV systems exceeds by far their consumption needs, and this signals a strong prosumer scheme (mainly large consumers in industry) where excess electricity is sold for the production of hydrogen and e-fuels. In addition, the use of solar PV systems in dedicated electrolysers reaches about one-third of the total electricity generation from solar in 2050. Deep geothermal and wind energy are also utilised to their maximum potential for electricity generation by 2050. Deep geothermal energy plays a significant role in the *SECUR* variant, as it contributes to about 4% in the total electricity supply and about 20% in the district heating supply.

Moreover, geothermal energy also contributes to the balancing of the energy system, and it fills, to some extent, the seasonal electricity gap. Finally, the use of hydrogen in fuel cells, i.e. Power-to-hydrogen-to-Power schemes, is less in *SECUR* than in *CLI* in 2050, as hydrogen is primarily used in fuel synthesis and for decarbonising the industrial heat and transport, and not for producing electricity and district heat via CHP fuel cells as in *CLI*.

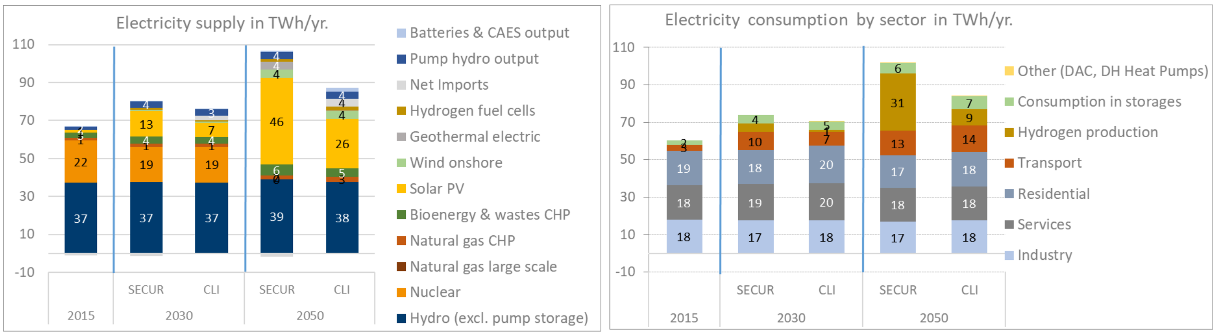


Figure 8.10: *Electricity production by technology (left) and consumption by sector (right)*

The *SECUR* variant achieves the net-zero ambition through an extensive activation of prosumer schemes and sector coupling, with hydrogen as a key element of the transition. All forms and pathways of Power-to-X are realised in this variant, indicating the importance of the Power-to-X and sector coupling technologies in maintaining the energy security and balancing the energy system.

The electricity consumption by sector is shown in figure 8.10. The figure illustrates a slightly lower electricity consumption in industry, residential and transport sectors, compared to the *CLI* scenario, due to the additional energy conservation measures and the shift to hydrogen-based mobility employed in *SECUR*. The overall electricity consumption increases more than two-thirds in 2050 from 2015 levels, because of the increased use of electricity for hydrogen production and e-fuels.

Because much of the balancing of the energy system is performed via electrolysis and synthetic e-fuels, the deployment of electric storages (i.e. batteries and pump storage) in *SECUR* is not much higher than in the *CLI* scenario, despite the higher penetration of variable renewable energy sources. As also mentioned above, the uptake of geothermal in electricity production also helps system balancing and mitigates the need for deploying additional storage.

8.2.4 Net imports and import dependency

The net imports in the *SECUR* variant significantly drop in 2050 and are mainly related to remaining imports of biofuels and e-fuels (figure 8.11). While it would be technically feasible to produce the residual imported amounts of zero-carbon fuels via electrolysis domestically, this would require large-scale deployment of ground-mounted solar PV systems, such as on agricultural land areas. In our analysis, we follow a conservative approach and we limit the deployment of ground-mounted solar PV systems.

The import dependency index in *SECUR* constantly remains below the index in *CLI* throughout the projection period. This also signals the technical feasibility of meeting the net-zero ambition target by mainly relying on domestic resources, notwithstanding the higher costs of transition in this case (see section 9.3). The *SECUR* variant also indicates that electrification alone cannot decarbonise the entire energy system. Biofuels and e-fuels are needed for uses where the direct use of electricity is challenging, and under limited availability of imported zero-carbon energy carriers, access to international markets for biofuels/e-fuels needs to be prioritised.

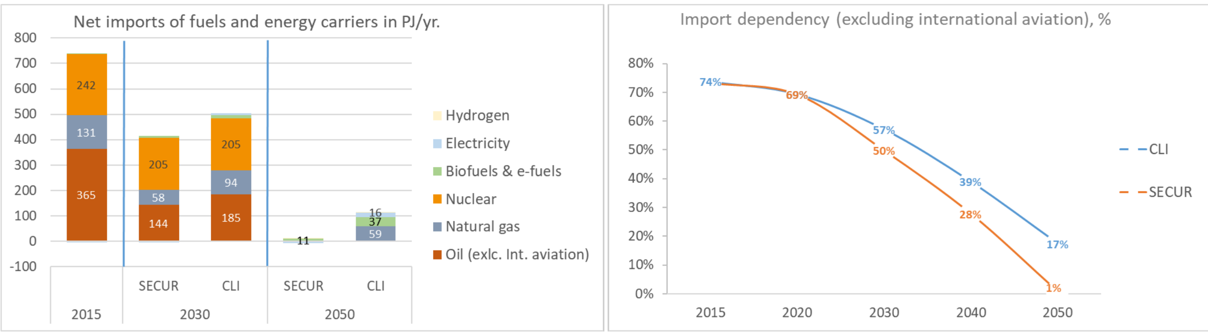


***Figure 8.11:** Net imports by fuel and energy carrier (left) and overall import dependency (right)*

8.2.5 CO_2 emissions and CC(U)S

Figure 8.12 shows the CO_2 emissions trajectory in the *SECUR* variant. As in the *CLI* scenario, the residential, and services are fully decarbonised in *SECUR* by 2050. Some remaining emissions of about 0.4 Mt CO_2 are in the transport sector by then, mainly from trucks, while the emissions from industry remain to the levels of *CLI*. A major difference between *SECUR* and *CLI* concerns the deployment of CC(U)S, where the *SECUR* variant requires about 1.2 Mt CO_2/yr. less carbon capture than *CLI*. In fact, the *SECUR* variant requires less capture from all the assessed variants in the analysis.

Less CO_2 capture is attributable to fewer imports of oil and natural gas that induce shifts to low-carbon choices in the fuel mix of the end-use sectors, accelerate deployment of energy conservation measures and avoid the deployment of SMR/ATR with CCS in hydrogen production. However, as is also discussed in section 9.3, the developments in the *SECUR* variant are associated with significant energy costs increases. Since the energy system in *SECUR* requires less negative emissions compare to *CLI*, DACCS is also much lower in this variant. Finally, in contrast to *ANTI*, the *SECUR* variant achieves all ETS targets, building standards, and vehicle emissions standards imposed in *CLI*.

The analysis of the *SECUR* variant also suggests that the complete phase-out of fossil fuels from the Swiss energy system could significantly reduce the amounts of captured carbon dioxide emissions. Also, to avoid high costs due to the exploitation of expensive domestic resources, availability of imports of zero-carbon energy carriers should be secured.

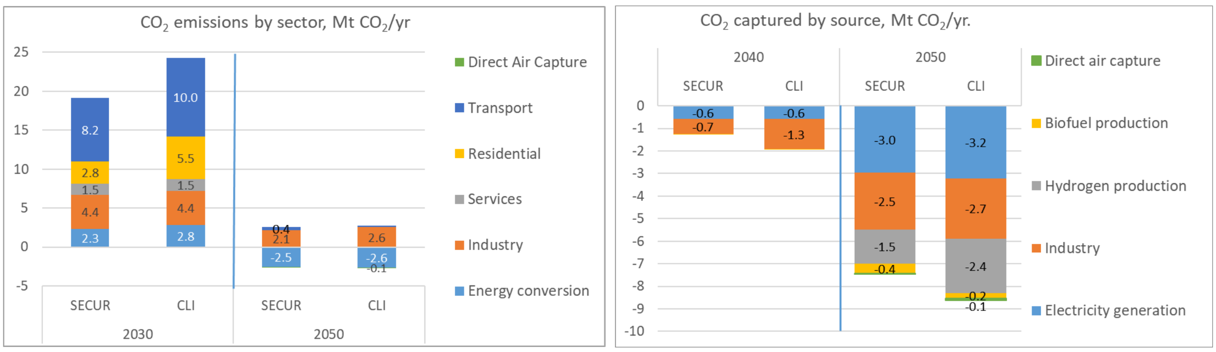


***Figure 8.12:** CO_2 emissions and CO_2 captured by sector; on-site CHP emissions are included in end-uses*

8.3 Achieving net-zero via higher integration of Swiss and international energy markets: variant *MARKETS*

The variant *MARKETS* considers higher global cooperation and integration of the Swiss, European and global energy markets than the *CLI* scenario. It additionally considers a stronger development of local energy markets in Switzerland, which are also coordinated efficiently with the national market. In this regard, there is facilitated access to internationally traded biofuels, synthetic fuels, electricity and hydrogen. The latter also implies that technologies involved in the production of hydrogen and e-fuels, which currently are mostly on the pilot stage, such as wood gasification, receive higher R&D infusions and mature quicker than in the *CLI* scenario. The increased worldwide innovation in hydrogen and Power-to-X technologies spillover in Switzerland. Hence, in the Swiss energy system, stronger "prosumage" schemes emerge, compared to the *CLI* scenario, together with sector coupling via Power-to-X pathways. The integration with international markets and the better coordination of local markets also imply a reinforcement of both the cross-border and domestic grid lines. Compared to the *SECUR* variant, *MARKETS* lifts the import dependency constraint, it assumes lower costs for technologies involved in "prosumage" and Power-to-X, such as decentralised generation, electrolysers, wood gasification for hydrogen, and storages, while it keeps the high renewable potentials and the levels of domestic grid expansion of *SECUR*. In addition, and in contrast to the *ANTI* and *SECUR* variants, the *MARKETS* variant assumes expansion of the cross-border capacities beyond the levels implemented in *CLI*. The variant is based on optimistic assumptions regarding Net Transfer Capacities and technology costs related to Power-to-X pathways reported in (Marcucci et al., 2020).

8.3.1 Final energy consumption

The *MARKETS* variant does not display significant differences in the fuel mix and total final energy consumption by end-use sector compared to the *CLI* scenario (see figure 8.13). The most important difference is the slightly higher electricity consumption in the post-2030 period in *MARKETS* compared to *CLI*, due to the stronger integration of the Swiss and European electricity markets.

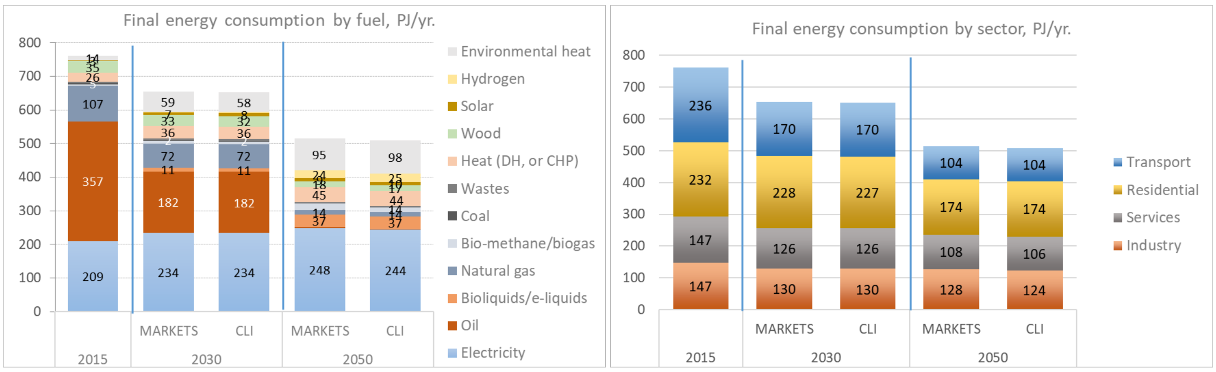


Figure 8.13: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

Because of the good availability of imported zero-carbon energy carriers, the *MARKETS* variant achieves all the sectoral emission targets (e.g. ETS, vehicle and building emissions standards) imposed in *CLI*, and implements all sectoral policies of *CLI*. The developments in the end-use sectors in *MARKETS* are also facilitated via the infrastructure expansion and the better integration of local markets to the national energy market, which in turn results in lower policy costs than in *CLI* (see section 9.3).

In the transport sector, the developments observed in *CLI* also hold in the *MARKETS* variant (figure 8.14). Both scenarios show a similar transition in mobility until 2030. In the post-2030 period, and mainly in the last decade of the projection horizon, there is a slightly higher electrification of the private cars in *MARKETS* compared to *CLI*, as electric vehicles are easier integrated into "prosumage" schemes than fuel cell vehicles. The stronger sector coupling via Power-to-X schemes in *MARKETS* also enables a slightly higher consumption of domestically produced synthetic e-liquids, mainly in the long-distance public and freight road transport.

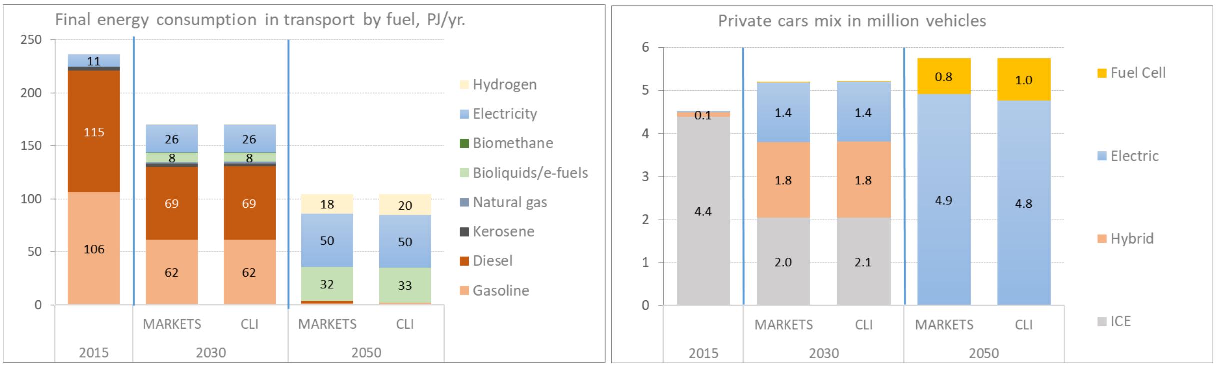


Figure 8.14: *Fuel consumption in the transport sector (left) and private cars fleet (right)*

8.3.2 Hydrogen production and consumption

The better integration of local markets, which is also enabled by Power-to-X pathways, brings an earlier introduction of hydrogen in the Swiss energy system compared to the *CLI* scenario. As shown in figure 8.15, the hydrogen production in *MARKETS* is already higher than in *CLI* in 2040, which relates to increased consumption of hydrogen and synthetic fuels in transport. Better access to international hydrogen markets also enables imports of hydrogen from northern countries (e.g. Norway). By 2050, the overal hydrogen production levels in *MARKETS* remain higher than in *CLI*, with a dominance of electrolysis and CCS. This result suggests that the development of domestic hydrogen production routes remains important even in a context with good availability of imports of hydrogen and e-fuels because the Power-to-X pathway contributes both to seasonal balancing (via electrolysis) and negative emissions (via wood gasification).

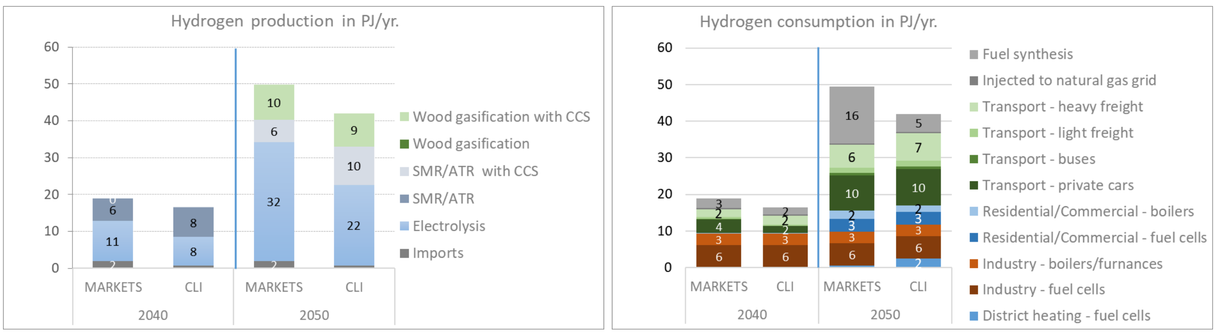


Figure 8.15: *Hydrogen production by technology (left) and consumption by sector (right)*

Regarding electrolysis, the leading technology developed in the *MARKETS* variant is PEM electrolysis, with very limited contributions from high-temperature SOEC electrolysis. As in the case of *SE-*

CUR, also in *MARKETS*, there is a development of electrolysis supplied by dedicated solar PV, which is deployed by 2040. By 2050 it accounts for more than one-third of the total hydrogen produced via electrolysis.

The consumption of hydrogen in the *MARKETS* variant shows a similar pattern in terms of sectors and consumed quantities with the *CLI* scenario. There is an earlier penetration of synthetic fuels production, which is facilitated by the deployment of electrolysis in the domestic hydrogen production and the availability of imported hydrogen. In this regard, the synthetic fuels produced in 2040 are carbon neutral and contribute to the decarbonisation of the mobility sector. By 2050, there is a shift in the production of synthetic fuels from liquids to gaseous fuels, as the mobility sector is further decarbonised with electricity and hydrogen, while the stationary sectors (mainly industry) are in need for zero-carbon gases. In *MARKETS* there is, however, a lower penetration of fuel cells in the district heating than in *CLI*, which is attributable to the development of smaller scale solutions of community-based heating, enabled by local markets: the introduction of fuel cell CHP plants in small local markets faces high upfront costs compared to more conventional solutions based on renewable energy (e.g. biomethane) and heat pumps.

8.3.3 Electricity production and consumption

The *MARKETS* variant puts an emphasis on decentralised generation, local energy markets and "prosumage" schemes, while there is better integration of the Swiss and international energy markets. This has an impact on the structure of the electricity generation (figure 8.16) as centralised options are not favoured. There is a deployment of solar PV systems to higher levels than the ones seen in the *CLI* scenario, throughout the projection period. In *MARKETS* about one-tenth of the electricity production from solar power is directed to dedicated electrolysis, as "prosumage" schemes are stronger in this variant than in *CLI*. The annual net-imports of electricity double in *MARKETS* by 2050, compared to *CLI*, at the expense of wind power, the deployment of which is limited, and it is only marginally higher than the current levels. Nevertheless, the increased deployment of solar PV induces a higher uptake of batteries than *CLI*, although the additional cross-border trade in *MARKETS* also contributes to the balancing of the energy system.

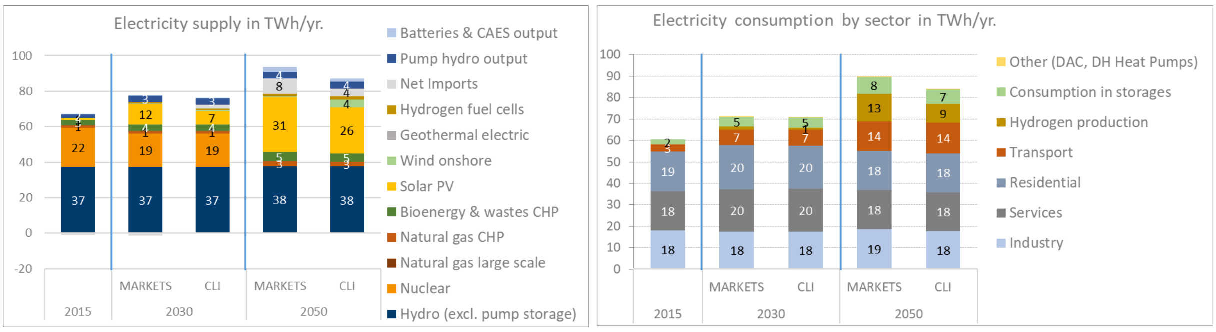


Figure 8.16: *Electricity production by technology (left) and consumption by sector (right)*

As regards the electricity consumption per sector, there are no significant differences with the *CLI* scenario, because in the *MARKETS* variant all the sectoral policies envisaged in the *CLI* scenario are implemented as well, while this variant assumes good availability of low carbon resources. The major source of the additional increase in the electricity demand is the production of hydrogen via electrolysis, and a slightly higher electrification of industry compared to *CLI*.

8.3.4 Net imports and import dependency

Figure 8.17 shows that the import dependency in *MARKETS* is not significantly higher than in *CLI* scenario, while the trend of lower reliance on imported energy over time also prevails.

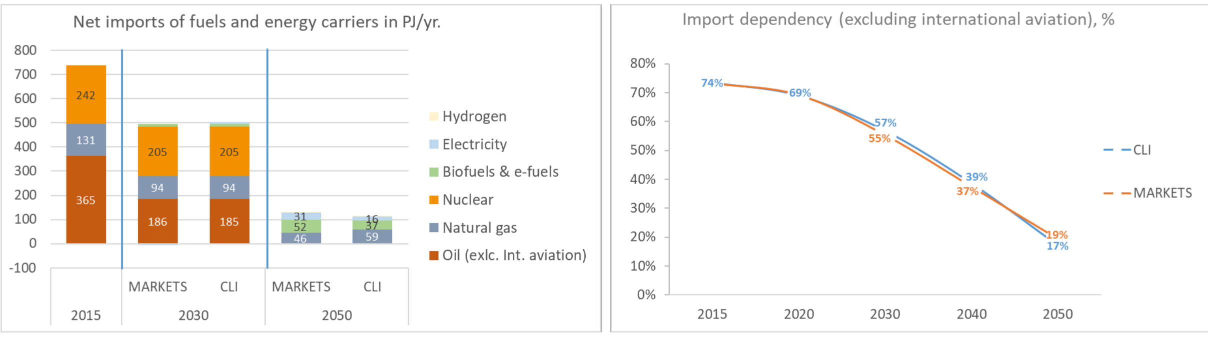


Figure 8.17: *Electricity production by technology (left) and consumption by sector (right)*

The trajectory and composition of the net-imports in *MARKETS* shows similarities with *CLI*. However, *MARKETS* displays lower imports of natural gas than in *CLI* and increased imports of electricity, hydrogen, biofuels and synthetic e-fuels. In the context of a globally coordinated action to mitigate climate change, these energy carriers play an important role worldwide and could be strong competition from other regions. The stronger integration of Swiss and international energy markets leads to a doubling in electricity imports and one-third increase in imported biofuels and e-fuels in 2050, compared to *CLI*. To put these quantities in a perspective, the imported electricity quantities in *MARKETS* in 2050, are twice the maximum electricity imports of the last 15 years, while the imported biofuels/e-fuels are seven times higher than in 2019.

8.3.5 CO_2 emissions and CC(U)S

MARKETS show similar developments in emissions as in *CLI*, following the similarity in energy mix (figure 8.18).This implies that the shift towards more distributed electricity and hydrogen production does not significantly impact the overall emissions as long as it is based on renewable energy.

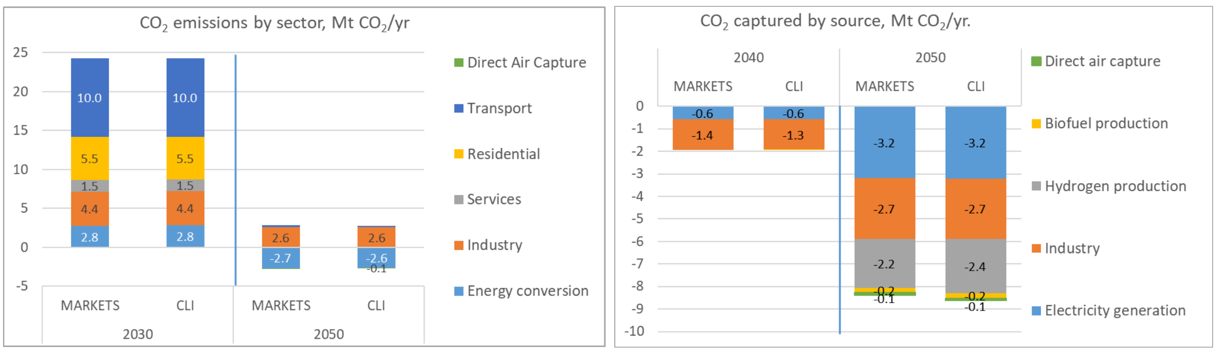


Figure 8.18: *CO_2 emissions and CO_2 captured by sector; on-site CHP emissions are included in end-uses*

8.4 Achieving net-zero under increased innovation: variant *INNOV*

The *INNOV* variant assumes a coordinated global action to reduce the costs of low-carbon technologies via increased R&D expenditures and innovation. Acknowledging the climate change as one of the key future challenges for the society, governments implement ambitious research, innovation and demonstration programmes supported with private co-financing. Sector coupling and Power-to-X options also receive R&D infusions to increase the means of affordable flexibility to the future energy system. The circular economy also reduces the need for materials and brings down the renovation costs and other conservation measures. The variant *INNOV* inherits all the assumptions of *MARKETS*, and it additionally assumes lower capital costs and increased efficiencies for a larger number of renewable, low-carbon and CCS technologies, both in energy supply and demand sectors. In this regard, the *INNOV* variant represents an optimistic development in technological progress and international cooperation to mitigate climate change. The implementation of *INNOV* considers the optimistic cost and efficiency improvements from (Bauer et al., 2019, 2017, Marcucci et al., 2020).

8.4.1 Final energy consumption

The final energy consumption in *INNOV* shows the same trends regarding the energy mix as in the *CLI* scenario, and it is also similar to *MARKETS* (figure 8.19). As in *MARKETS*, also *INNOV* shows a higher electrification of the demand in the post-2030 period, compared to *CLI*. In addition, the total levels of final energy consumption are slightly lower in *INNOV* than *CLI*. The lower energy consumption is attributable to the lower cost of renovation and energy conservation measures (due to circular economy reducing materials' cost), which in turn enable their higher uptake in the end-use sectors, and to the technology improvement of electric and fuel cell vehicles both in terms of ownership costs and performance.

However, the fuel mix in energy consumption in *INNOV* shows a decline in the hydrogen consumption compared to *CLI*, and to *MARKETS*, in 2050. This development is also related to the transport sector, because the improved performance of batteries increases the competitiveness of electric vehicles at the expense of those with fuel cell drivetrains. There is also improvement in the efficiency of fuel cell vehicles as well, that reduces further the hydrogen consumption in those segments where it penetrates.

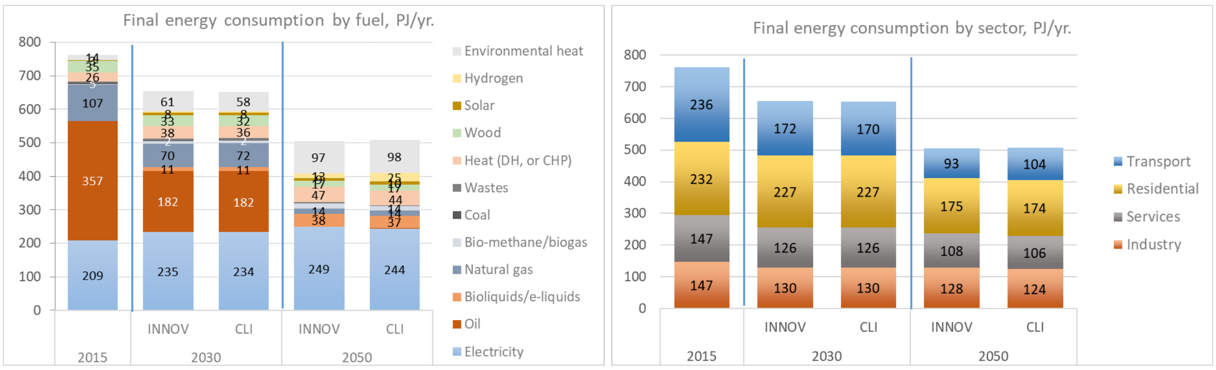


Figure 8.19: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

Already in 2030, the private cars sector displays higher electrification in *INNOV* than in *CLI* (figure 8.20). Until the mid-term period, there is less hybridisation in the transport sector in *INNOV* compared to *CLI*, and more electric and conventional cars. This is driven by the systemic effects of the mitigation, as the lower renovation and energy conservation costs in the stationary sectors enable further emissions reductions in these sectors, which relieve the transport sector to mitigate beyond the vehicle emissions standards. Another driver for less hybridisation of the transport sector in *INNOV* is the technology improvement of battery electric vehicles that accelerates their deployment earlier in the energy system, constituting less need for transition technologies like hybrids.

Despite the higher electrification of the private cars sector, the electricity consumption in transport does not significantly increase in *INNOV* compared to the *CLI* scenario. This is because of the improvement of the efficiency of EVs, which is partly attributable to the improvement of batteries per se, and partly attributable to the improvement of the designs and materials of EVs. For instance, user-centric designs which directly or indirectly impact consumption in a significant way, including visibility, thermal comfort, ergonomics, postural comfort, noise and vibration, etc., or integration of advanced systems and components to optimise occupant comfort and well-being with respect to energy consumption, or, finally, novel materials to improve thermal insulation and hence reduce energy consumption needs. New designs and materials for EVs are currently researched worldwide[1].

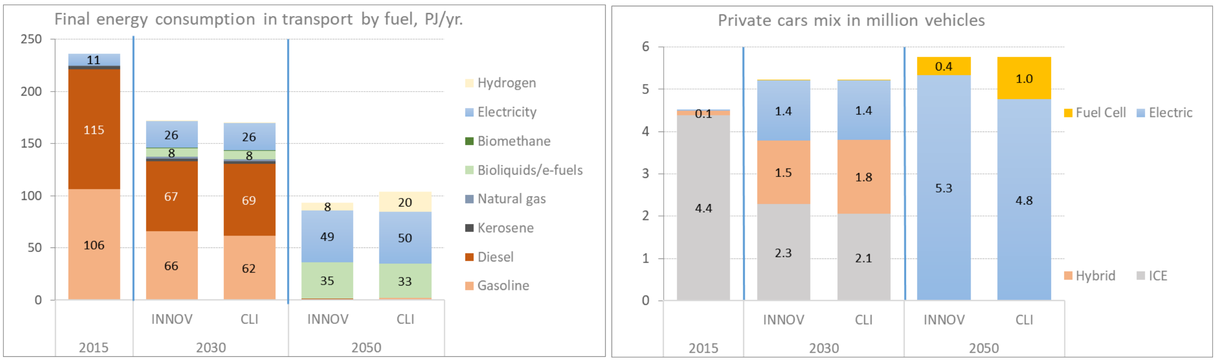


Figure 8.20: *Fuel consumption in the transport sector (left) and private cars fleet (right)*

8.4.2 Hydrogen production and consumption

Similar to *CLI*, domestic hydrogen production in 2050 in the *INNOV* variant is mainly based on electrolysis, SMR/ATR with CCS and wood gasification with (figure 8.21). The uptake of SMR/ATR with CCS is, however, lower than in *CLI* because electrolysis is more cost-effective after achieving further cost reductions in this variant.

The hydrogen demand in *INNOV* is lower than in *CLI* because of the less hydrogen consumption in the transport sector. This is attributable to the improvement of the efficiency of the fuel cell vehicles in the long-distance public and freight transport, and the lower penetration of private fuel cell cars due to higher market shares of electric vehicles. In contrast, the hydrogen consumption in the stationary sectors remains at the levels seen in the *CLI* scenario. In *INNOV* there is also increased use of hydrogen for the production of synthetic gas. This is driven by the cost reduction of the Power-to-X technologies assumed in the variant. The fuel synthesis with hydrogen and captured carbon dioxide starts in *INNOV* in 2040. The seasonal balancing in *INNOV* is mainly achieved via fuel synthesis and to a lesser extent through dedicated hydrogen storage. This is attributable to the lower production

[1]See for example https://cordis.europa.eu/search?q=contenttype%3D%27project%27%20AND%20programme%2Fcode%3D%27GV-05-2017%27&p=1&num=10&srt=/project/contentUpdateDate:decreasing

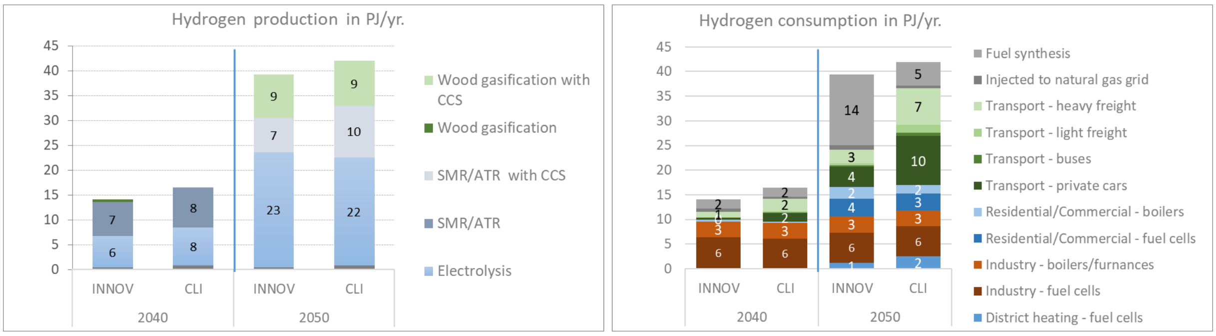


Figure 8.21: *Hydrogen production by technology (left) and consumption by sector (right)*

costs of hydrogen, which result in reduced consumer prices and hampers the economics of (expensive) hydrogen storage vessels. Compared to *MARKETS*, which also place emphasis on Power-to-X schemes, the *INNOV* variant shows similarities in the hydrogen production mix. Regarding the hydrogen consumption, *INNOV* shows a higher penetration of stationary fuel cells, and to the levels seen in *CLI*, which is enabled by the lower investment costs. The hydrogen consumption for fuel synthesis is in *INNOV* similar to the levels seen in *MARKETS*, as both variants assume the same developments in the production cost of e-fuels.

8.4.3 Electricity production and consumption

As in the case of *MARKETS*, *INNOV* also emphasises on decentralised generation, "prosumage" and higher integration of the Swiss and European electricity markets (figure 8.22). Accordingly, the developments seen in the electricity generation technology mix in *INNOV* are similar to those described for the MARKETS variant in 8.3.3. However, since the *INNOV* variant uses less electricity for hydrogen production than *MARKETS*, the deployment of solar PV remains at the levels seen in *CLI*. The electricity net-imports in *INNOV* are twice the net imports of *CLI*, at the expense of electricity generation from wind. The deployment of batteries in *INNOV* is also similar to *CLI*, and, as in the case of *MARKETS*, the increased volume of cross-border trade also contributes to the grid balancing.

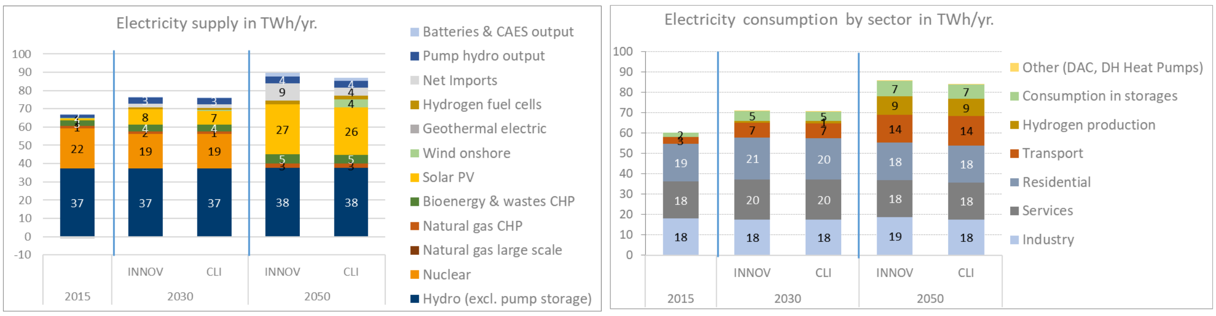


Figure 8.22: *Electricity production by technology (left) and consumption by sector (right)*

Compared to *CLI*, the electricity consumption in the end-use sectors is sustained in *INNOV* throughout the projection period. In combination with the reduction of the non-electric consumption, due to increased deployment of renovation and energy conservation measures, there is higher overall electrification of demand in 2050 than in *CLI*. The largest difference in the electricity consumption between *INNOV CLI* occurs in hydrogen production.

8.4.4 Net imports and import dependency

Regarding the import dependency the *INNOV* variant displays similar trends with *MARKETS*, with a slightly higher import dependency than in *CLI* due to the increased availability of electricity and zero-carbon e-fuels imports (figure 8.23). In contrast to *MARKETS*, where also the mid-term imports of fuels show similarities with *CLI*, in *INNOV* there is less imports of natural gas and higher imports of oil in 2030. This is because of the earlier deployment of energy conservation measures in the end-use sectors, facilitated by the reduction of costs, and the higher uptake of conventional vehicles in transport in *INNOV*, in 2030. In the long-run the net imports in *INNOV* are about 2% less than in *MARKETS*, due to the efficiency improvement of energy technologies, and similar to *CLI*.

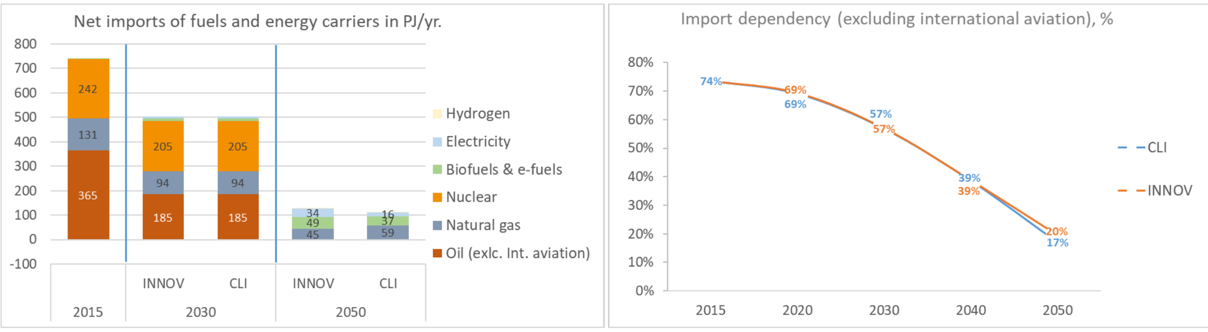


Figure 8.23: *Net imports by fuel and energy carrier (left) and overall import dependency (right)*

8.4.5 CO_2 emissions and CC(U)S

Given the similarity in the developments in the final energy consumption between *INNOV* and *CLI*, the CO_2 emissions in *INNOV* are comparable with those of the *CLI* scenario. Moreover, by comparing figure 8.18 and figure 8.24 it can be argued that the mitigation pathway followed in *INNOV* is very similar to the one in *MARKETS*. However, the requirements in negative emissions in *INNOV* is less than in *MARKETS* and *CLI* scenarios in 2050, due to efficiency gains in energy conversion and consumption (figure 8.24). Finally, the *INNOV* variant meets all sectoral emissions targets of *CLI*.

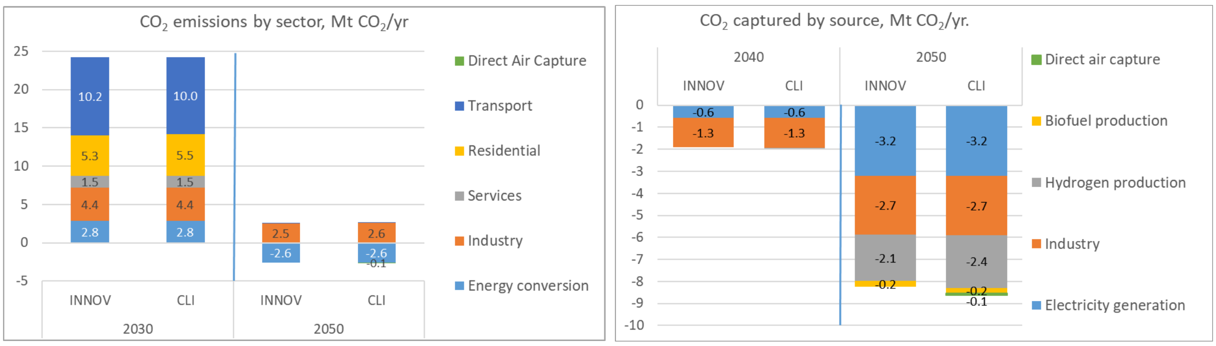


Figure 8.24: *CO_2 emissions and CO_2 captured by sector; on-site CHP emissions are included in end-uses*

8.5 Less stringent energy efficiency and climate targets

8.5.1 Relaxing the electricity consumption per capita target in *EPOL*: variant *EPOL-E*

The *EPOL* scenario implements the indicative target of reducing the average electricity per capita by 13% in 2030 and by 18% in 2050 compared to 2000 levels. This constraint is lifted in the variant *EPOL-E*, which tries to provide insights into the impact of constrained electricity consumption on the achievement of the overall efficiency targets of *EPOL*. All other assumptions and policies included in *EPOL* remain also in the *EPOL-E* variant.

8.5.1.1 Final energy consumption

Lifting the constraint on electricity per capita induces further electrification of the demand, as shown in figure 8.25. In the stationary sectors, there is a higher penetration of heat pumps, mainly in the residential sectors, and less consumption of heat (either produced on-site or supplied by district heating) in the industrial and buildings sectors. In the transport sector, there is a further shift away from oil in favour of electricity.

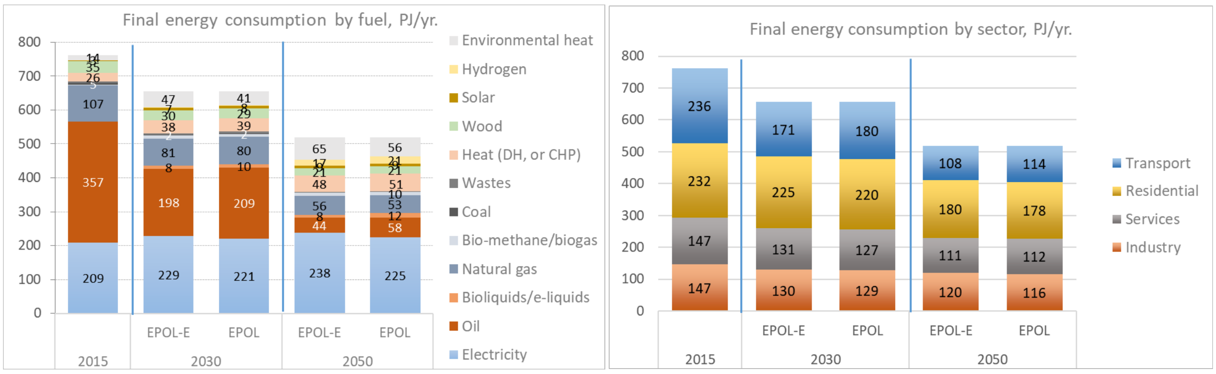


Figure 8.25: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

The total final energy consumption remains at the same level as in *EPOL* to be able to meet the overarching efficiency target of reducing the total average final energy consumption per capita by 43% in 2035 and by 54% in 2050 from 2000 levels.

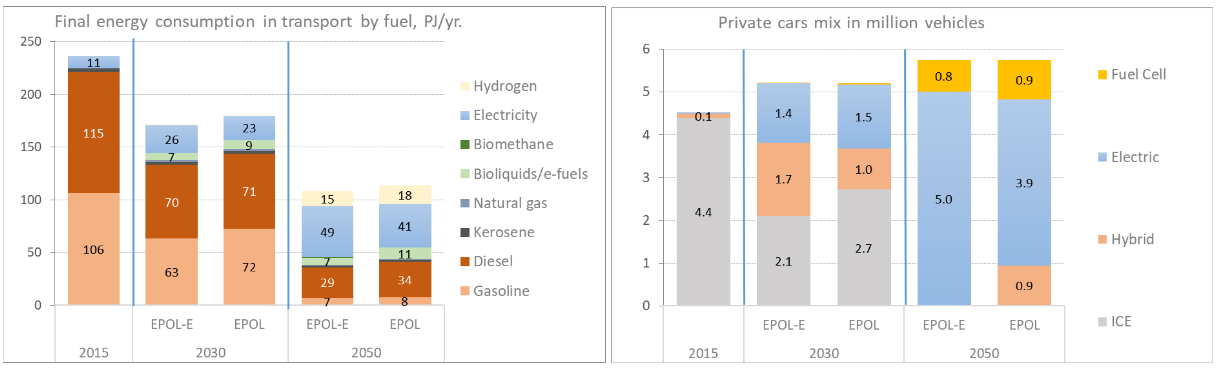


Figure 8.26: *Fuel consumption in the transport sector (left) and private cars fleet (right)*

In transport, there is a higher uptake of electric cars towards the last two decades of the projection period in *EPOL-E* compared to *EPOL* (figure 8.26), at the expense of hybrids and fuel cells. *EPOL-E* achieves an accelerated transition to low carbon mobility. Even in the mid-term period until 2030, the hybridisation in *EPOL-E* is more than 50% higher than in *EPOL*, at the expense of conventional cars. Thus, the transition towards low- and zero-carbon mobility is facilitated by allowing a higher electricity consumption per capita in *EPOL-E* compared to the *EPOL* scenario.

8.5.1.2 Hydrogen production

As already discussed along with the *EPOL* scenario, hydrogen penetrates the energy system as an alternative carrier to electricity to decarbonise the end-use sectors, especially under restrictions in the average electricity consumption per capita. As this constraint is relaxed in *EPOL-E*, resulting in a higher electrification of demand, the consumption of hydrogen declines and the production of hydrogen is much lower than in the core *EPOL* scenario (figure 8.27).

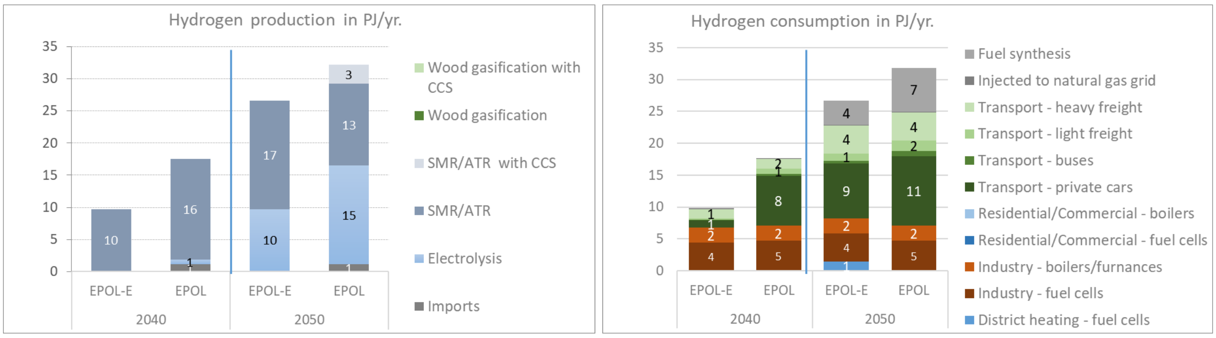


Figure 8.27: *Hydrogen production by technology (left) and consumption by sector (right)*

Regarding the production mix, SMR/ATR dominates the production in 2040, as in *EPOL*. In 2050, there is an increased contribution from electrolysis, but not to the levels seen in the *EPOL* scenario, since the overall hydrogen supply requirements are lower. Moreover, in *EPOL-E* there is no penetration of SMR/ATR with CCS, as the increased electrification of the stationary sectors and transport reduces the need to deploy carbon capture and storage in hydrogen production to partially offset emissions from the end-use sectors. The consumption of hydrogen shows a similar pattern as in *EPOL*, with hydrogen penetrating in all end-use sectors, including fuel synthesis, but at lower levels than in *EPOL*. In *EPOL-E* also hydrogen in district heating fuel cells is emerging, which is not the case in *EPOL*, as a cost-effective option to provide heat in industry and the buildings sector.

8.5.1.3 Electricity production and consumption

The electricity consumption in *EPOL-E* is higher in all end-use sectors than in *EPOL* throughout the projection period, since electricity is a key energy carrier for achieving efficiency gains in the demand sectors. In 2050, there is also increased electricity consumption for producing hydrogen compared to *EPOL*. Thus, the overall electricity supply in *EPOL-E* is about 2 TWh higher than in *EPOL* in 2050 (figure 8.28). The incremental electricity supply in *EPOL-E* in 2050, is met with additional net imports of electricity and increased cogeneration. There is no higher deployment of solar PV or wind in *EPOL-E* than *EPOL* because there is no strong price signal to foster investments in these two renewable options, in the absence of a rigid climate policy in the scenario.

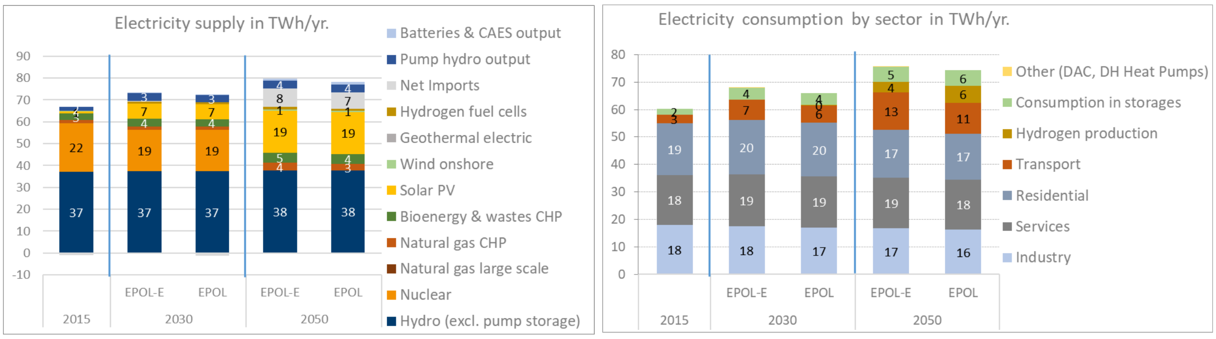


Figure 8.28: *Electricity production by technology (left) and consumption by sector (right)*

8.5.1.4 Net imports and import dependency

The net imports in *EPOL-E* variant remain at lower levels than in *EPOL* throughout the whole projection period. As shown in figure 8.29, due to the higher electrification of the demand, there are fewer requirements for importing fossil fuels compared to the core scenario, and in particular oil products for the transport sector. Moreover, the shift in the transport sector from conventional engines to hybrid and electric drivetrains also reduces the need for imported biofuels and e-fuels in *EPOL-E* compared to *EPOL* in 2050.

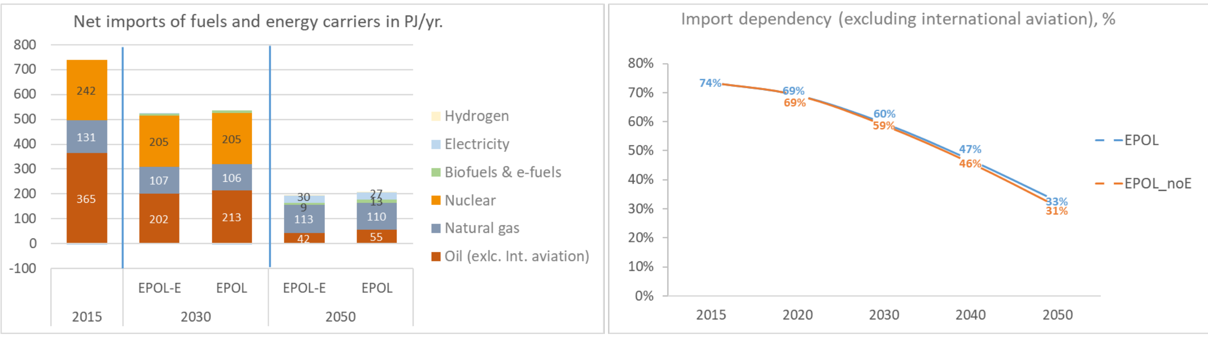


Figure 8.29: *Net imports by fuel and energy carrier (left) and overall import dependency (right)*

The above analysis of the developments in final energy consumption, in the energy conversion and the import dependency, indicates that imposing restrictions in the electricity consumption can lead to inefficiencies in the configuration and operation of the energy system, as well as conflicts with other energy and climate policies. These inefficiencies can result in higher energy system costs (see also section 9.3). Thus, coordinated policy implementation and action is necessary when aiming at ambitious energy and climate targets to enable cost-effective pathways.

8.5.1.5 CO_2 emissions and CC(U)S

The overall CO_2 emissions in *EPOL-E* are lower than in the core *EPOL* scenario due to higher electrification of the demand. The largest difference is shown for services and residential sectors, where the penetration of heat pumps in space and water heating helps in avoiding about 0.6 Mt CO_2/yr. in 2050, when comparing to *EPOL*, while the additional emissions reduction in the transport sector reaches at 0.4 Mt CO_2/yr. over the same period. This climate benefit of removing an additional 1 Mt CO_2/yr. from the Swiss energy system in 2050 is not achieved when a constraint on electricity consumption per capita is imposed (figure 8.30). Regarding CCS, the two scenarios display similar developments, with the only difference being the absence of SMR/ATR with CCS in *EPOL-E*. In the *EPOL* scenario, the SMR/ATR with CCS is mainly deployed to meet the ETS targets and partially offset emissions from the end-use sectors. However, in *EPOL-E* the increased availability of electricity in the end-use sectors facilitates decarbonisation of industry also by deploying additional CO_2 capture (which requires electricity for its operation). In addition, the incremental needs in electricity supply also result in an expansion of the CO_2 capture in the power sector, constituting not cost-effective the deployment of additional gas-based CCS in hydrogen production, so that the ETS sectors in industry and energy conversion meet the assumed linear emissions reduction factor.

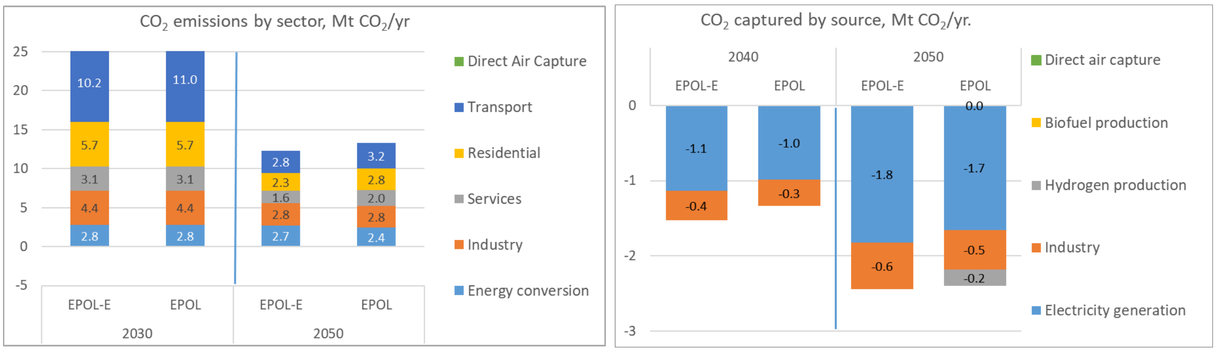


Figure 8.30: *CO_2 emissions and CO_2 captured by sector; on-site CHP emissions are included in end-uses*

8.5.2 Relaxing emission standards and sectoral policies in *CLI*: variant *CLI100*

Inspired by SCCER Efficient Technologies and Systems for Mobility, the *CLI100* variant developed in SCCER JASM relaxes the emissions standards for vehicles in the transport sector to provide additional insights on the impact that such vehicle standards may have in the decarbonisation trajectory of the mobility sector. At the same time, it also assumes relaxed building emissions standards in the residential and services sectors. In this regard, the emissions standards for vehicles, residential and commercial buildings are imposed until 2030 and are then kept constant until 2050. In contrast, as also discussed in section 2.2, in the *CLI* scenario, the standards become more stringent after 2030.

Besides the relaxation of the buildings and vehicles standards, *CLI100* also does not assume a strengthening of the ETS linear factor beyond 2030, in contrast to *CLI*. In this context, the *CLI100* does not implement the entire spectrum of the policies and measures described in the revision of the CO_2 law (SFOEN, 2020b). As the sectoral emissions targets are lifted in this scenario, *CLI100* can be considered to be closer to the *Least Cost* solution, which is obtained when the model is free to take decisions without implementing additional policies except for the overarching CO_2 emissions reduction targets.

8.5.2.1 Final energy consumption

The final energy consumption in *CLI100* shows similar developments as in *CLI* (figure 8.31). The main difference is located at the consumption of natural gas, which is higher in *CLI100* compared to *CLI*, at the expense of hydrogen and on-site heat from distributed CHP plants. This is attributable to the relaxation of the emission standards in buildings and the less stringent emissions reduction requirements in the ETS sectors. By relaxing sectoral emissions targets, the most expensive zero-carbon options, such as hydrogen and heat from distributed CHPs, do not scale up to the levels seen in the *CLI* scenario. Moreover, the overall energy consumption in *CLI100* in the residential and services sectors is higher than in *CLI*. This is because the deployment of energy conservation measures in *CLI100* remains below the levels of *CLI*, as the sectoral emissions reduction targets in buildings are relaxed. At the same time, the consumption in industry is lower in the long-term, because of the less need for CO_2 capture than in *CLI*, since the ETS linear emission reduction factor is not so steep as in the core decarbonisation scenario.

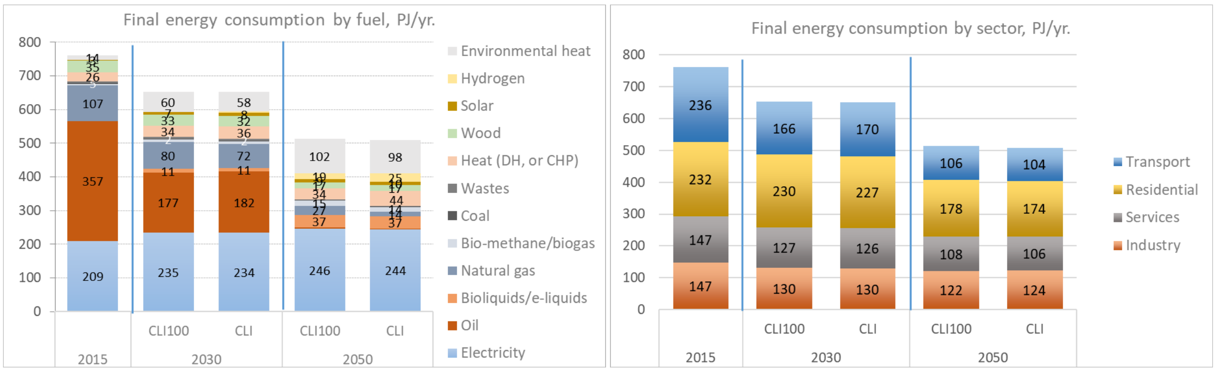


Figure 8.31: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

As shown in figure 8.32, the decarbonisation trajectory in the transport sector in the *CLI100* scenario looks quite similar to *CLI*. The main differences are the increased hybridisation of the mobility in 2030/40, the higher uptake of electric plug-in cars in the last decades of the projection period at the expense of battery electric and fuel cell vehicles, and the stronger reliance of the long-distance public and freight transport on synthetic fuels instead of hydrogen.

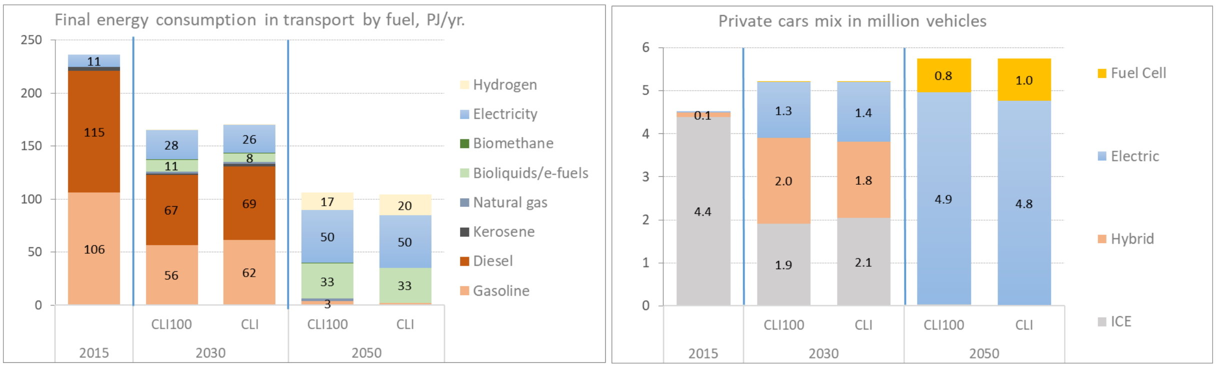


Figure 8.32: *Fuel consumption in the transport sector (left) and private cars fleet (right)*

The reason of the stronger hybridisation of mobility in *CLI100* compared to *CLI* in the mid-term horizon relates to the cross-sectoral burden-sharing to provide the necessary emission reductions, where the relaxation of the building standards requires the transport sectors to take more share in the overall decarbonisation effort. The higher uptake of plug-in cars in 2050 is attributable to the absence of more stringent vehicle emissions standards in 2050, beyond the levels of 2030. There are additional 700,000 plug-in hybrids in *CLI100* than in *CLI* by 2050, at the expense of battery electric cars (which are half a million less) and fuel cell vehicles (which are 200,000 less). The plug-in cars in *CLI100* are fuelled by biofuels and imported zero-carbon e-fuels. Finally, the long-distance public and freight road transport follow the developments in the *CLI* scenario until 2030. In the post-2030 period there is a higher uptake of synthetic fuels in *CLI100* than in *CLI*, at the expense of hydrogen. This trajectory is also attributable to the absence of stricter requirements in these sectors to reduce the vehicle-specific emissions in 2050 beyond the levels of 2030.

Despite these differences, the decarbonisation trajectories in the transport sector are similar in *CLI100* and *CLI*, as there is a shift from conventional drivetrains to electric and fuel cell ones. This outcome denotes that the ambition to reach net-zero by 2050 requires, in any case, zero-carbon mobility in the last decade of projection.

8.5.2.2 Hydrogen production

Hydrogen emerges in *CLI100* later than *CLI*, due to the relaxation of the intermediate sectoral emissions reduction targets that mitigates the need for zero-carbon energy carriers in the end-use sectors in the near-to-mid term period (figure 8.33). However, while in 2040 the hydrogen consumption in *CLI100* is half the consumption in *CLI*, by 2050 both scenarios end up at a similar level. This suggests that reaching net-zero by 2050 requires scaling up of the hydrogen demand, particularly in the last decade of the projection horizon.

Regarding the technology mix for the production of hydrogen, both scenarios show similar developments. Electrolysis and wood gasification with CCS are the key technologies in hydrogen supply. However, in *CLI100* there is a lower penetration of SMR/ATR than in *CLI*. This is mainly attributable to the higher emissions in the end-use sectors in *CLI100* than in *CLI*, which challenge the flexibility of the system to offset additional emissions from gas-based hydrogen production, in order to reach the net-zero emissions in 2050. The hydrogen production in *CLI100* has lower carbon intensity than in *CLI* in 2050. Finally, hydrogen imports are twice the imports in *CLI* in 2050.

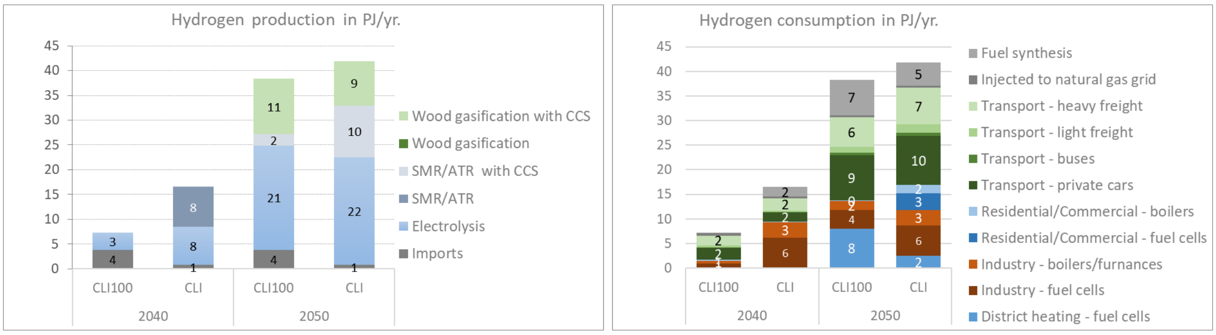


Figure 8.33: *Hydrogen production by technology (left) and consumption by sector (right)*

The consumption of hydrogen in *CLI100* shows a similar pattern as in the *CLI* scenario. The main differences are the increased use of hydrogen for synthetic fuels, due to the developments in the transport sector, and higher hydrogen penetration in district heating applications via fuel cell CHP plants. In contrast, there is practically no direct consumption of hydrogen in buildings. Therefore, in *CL100* hydrogen penetrates residential and commercial sectors indirectly, via synthetic fuels and district heating. This is because there is no requirement in *CLI100* to have net-zero emissions new buildings that would imply the direct use of zero-carbon carriers. As buildings still emit in 2050, the burden for emissions reductions is shifted to the energy conversion sectors, and in this case to the district heating sector, which deploys renewable and other zero-carbon energy carriers (like hydrogen) to decarbonise its supply.

8.5.2.3 Electricity production and consumption

The electricity production mix in *CLI100* is the same as in *CLI* throughout the projection period (figure 8.34). Similarly, the penetration of electricty in the demand sectors is also at the levels of *CLI*, with the exception of lower electricity consumption in hydrogen production (due to the lower demand for hydrogen) and in industry (due to the less deployment of electricity-intensive CCS).

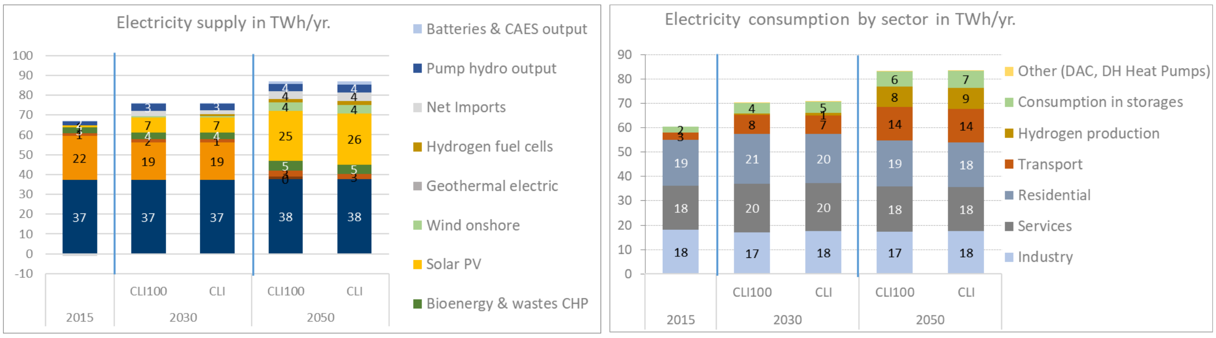


Figure 8.34: *Electricity production by technology (left) and consumption by sector (right)*

8.5.2.4 Net imports and import dependency

In the mid-term there are increased net-imports of natural gas in *CLI100* compared to *CLI*, because of the absence of stringent sectoral emissions reduction targets. By 2050, the mix of net-imports in *CLI100*, as well as their level, is very close to *CLI*. Figure 8.35 contrasts the developments in net-imports in the *CLI100* variant with the ones observed in the *CLI* scenario.

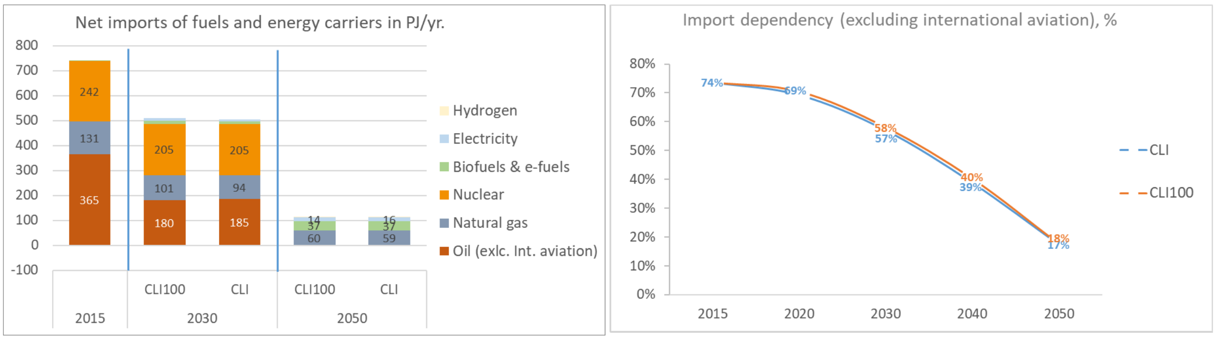


Figure 8.35: *Net imports by fuel and energy carrier (left) and overall import dependency (right)*

8.5.2.5 CO_2 emissions and CC(U)S

Due to the relaxation of the emissions standards and ETS linear reduction factor, the *CLI100* variant results in higher emissions in the end-use sectors than *CLI*. Hence, it requires additional amounts of CO_2 capture and a higher reliance on negative emissions technologies. A key insight from the variant is the shift of bioenergy from residential and services sectors in *CLI* to industry and energy conversion sectors in *CLI100*, where BECCS can be deployed to offset emissions from the rest of the energy system. Thus, the electricity generation sector delivers increased negative emissions in *CLI100* compared to *CLI*, while the emissions in industry in *CLI100* are also lower in 2050, due to the higher availability of biogenic gases, which in *CLI* are used in buildings to meet the emissions standards in residential and services. (figure 8.36).

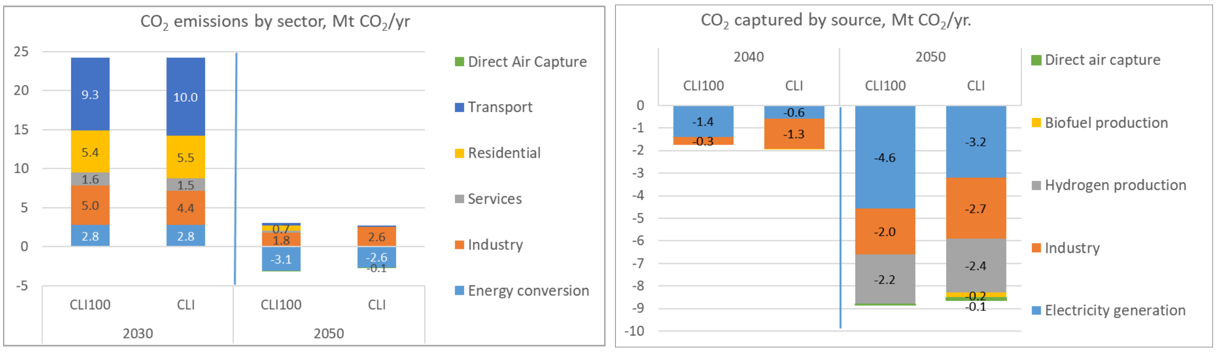


Figure 8.36: *CO_2 emissions and CO_2 captured by sector; on-site CHP emissions are included in end-uses*

8.5.3 Relaxing the climate ambition targets in *CLI*: variant *CLI80*

A second variant, *CLI80*, also inspired by SCCER Efficient Technologies and Systems for Mobility, explores the future developments in the Swiss mobility sector in a context of an emission mitigation pathway that achieves 80% reduction in the CO_2 emission from the energy system, and industrial processes, in 2050 compared to 1990 levels. The variant *CLI80* includes all the assumptions of *CLI100*, i.e. it maintains constant the levels of 2030 during the whole period 2030 – 2050 of the building and vehicle emissions standards, as well as ETS linear reduction factor. The *CLI80* is compatible with a global emissions trajectory to limit the increase of the average global temperature to 2^{o}C by the end of the century from the pre-industrial levels.

8.5.3.1 Final energy consumption

Figure 8.37 summarises the final energy consumption mix and the consumption by sector. Going from *CLI80* to *CLI*, would mainly require to increase the renovation and efficiency primarily in residential and services.

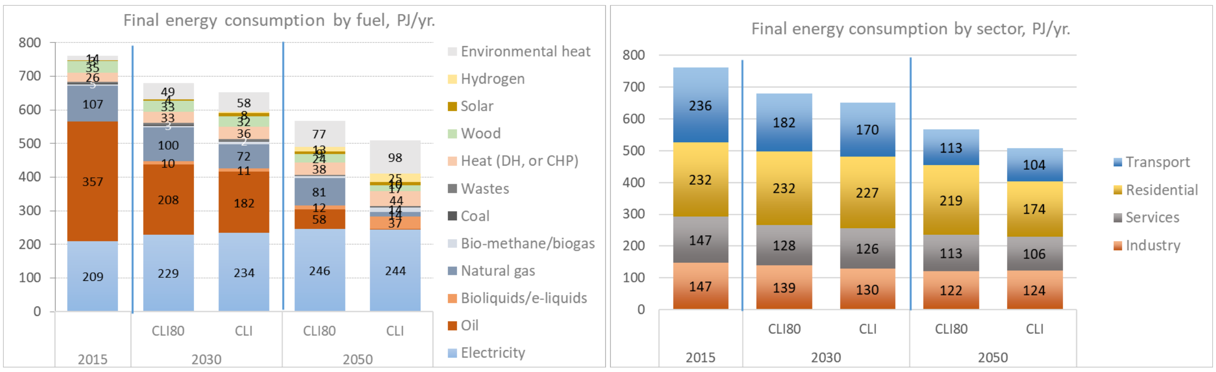


Figure 8.37: *Final energy consumption by fuel and sector, excl. international aviation and on-site CHPs*

CL80 still maintains fossil fuels in the final energy mix, and in particularly in the buildings sector, which in *CLI* is fully decarbonised. In contrast, the developments in industry between *CLI80* and

CLI are less pronounced. In transport, the achievement of net-zero emissions requires that the long-distance freight and public road transport shifts away from fossil fuels. The above outcomes suggest that critical sectors in meeting climate change ambitions in Switzerland are buildings and long-distance freight and public transport, the decarbonisation of which can be achieved by using a portfolio of clean energy solutions that largely exist today (e.g. heat pumps, electric cars, building renovations, solar energy).

Figure 8.38 summarises and contrasts the fuel consumption in transport and composition of private cars in *CLI80* and *CLI* scenarios. The fuel mix in transport *CLI80* remains at a substantial share fossil-based compared to *CLI*, but fossils are mainly consumed in the long-distance road transport. The private cars sector shifts to electromobility, as in the *CLI* scenario. The main difference between *CLI80* and *CLI* in the fleet of private cars is the lower deployment of fuel cell cars in *CLI* and the penetration of conventional hybrids instead, particularly for large-sized private cars.

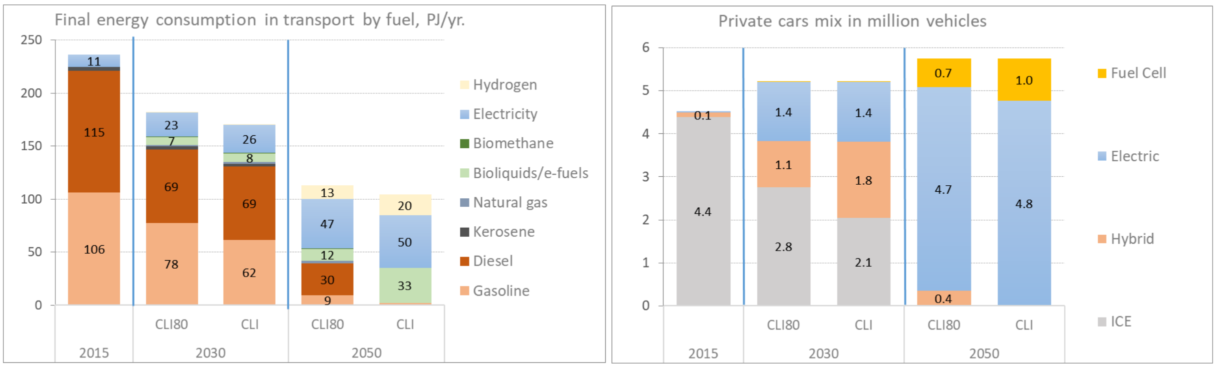


Figure 8.38: *Fuel consumption in the transport sector (left) and private cars fleet (right)*

This outcome suggests that the electrification of the private cars in Switzerland is already gaining momentum, and even under less stringent climate change mitigation effort electric drivetrains are likely to dominate the market by 2050. The transition to low-carbon private mobility starts soon, even by 2030. Emission standards in vehicles drive the early stages of the transition, but in the post-2030 period, the overarching target to reduce emissions in the Swiss energy system accelerates the diffusion of alternative vehicles.

8.5.3.2 Hydrogen production

Hydrogen emerges at *CLI80* a decade later than *CLI* (figure 8.39). Its production mix is similar to *CLI100*, with electrolysis, wood gasification with CCS and SMR/ATR with CCS being the main supply options. As the demand for hydrogen is less in *CLI80* than in *CLI100* there is no imported quantities of hydrogen. The pattern in hydrogen consumption in the variant is also similar to *CLI*.

Hence, hydrogen can facilitate tackling ambitious climate change mitigation targets due to its versatility in supply and consumption. However, the timing of the transition to hydrogen economy depends both on the stringency of the climate policies as well as on the creation of demand for hydrogen by achieving the cost reductions in fuel cells expected by industry.

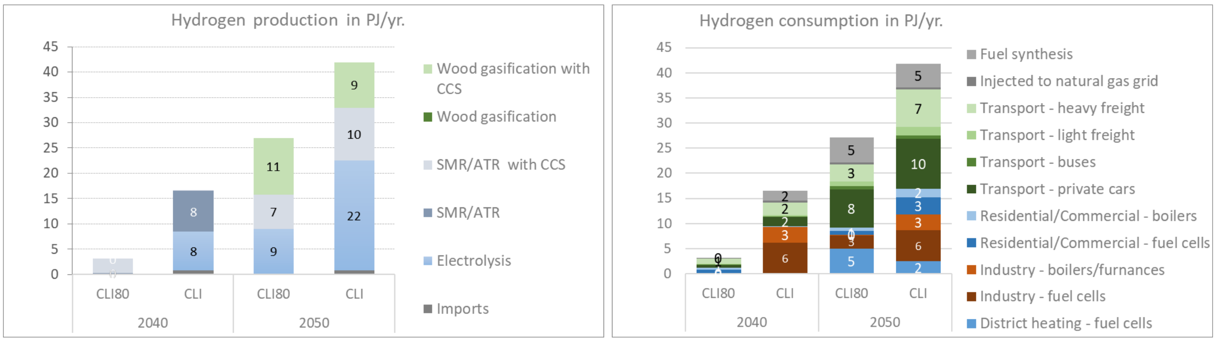


Figure 8.39: *Hydrogen production by technology (left) and consumption by sector (right)*

8.5.3.3 Electricity production and consumption

The electricity production mix in *CLI80* is shown in (figure 8.40). Going from *CLI80* to *CLI* would require increased deployment of solar PV and wind power. The electricity consumption shows similar patterns between the variant and the core scenario.

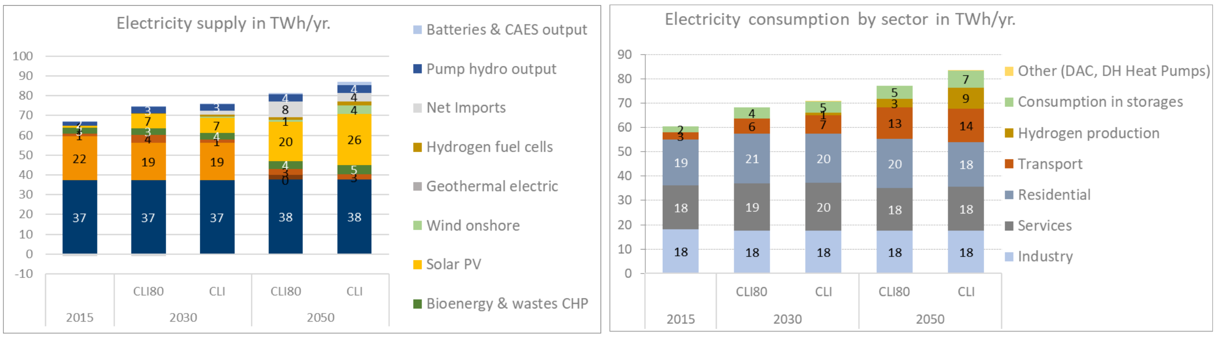


Figure 8.40: *Electricity production by technology (left) and consumption by sector (right)*

8.5.3.4 Net imports and import dependency

The less climate change mitigation effort in *CLI80* compared to *CLI* maintains higher net imports of energy carriers throughout the projection period, as energy conservation measures and efficiency gains via technology and fuel switch are lower. Moreover, there are still substantial amounts of imports of fossil carriers, as the end-use sectors are not achieving deep emissions reductions as in *CLI*.

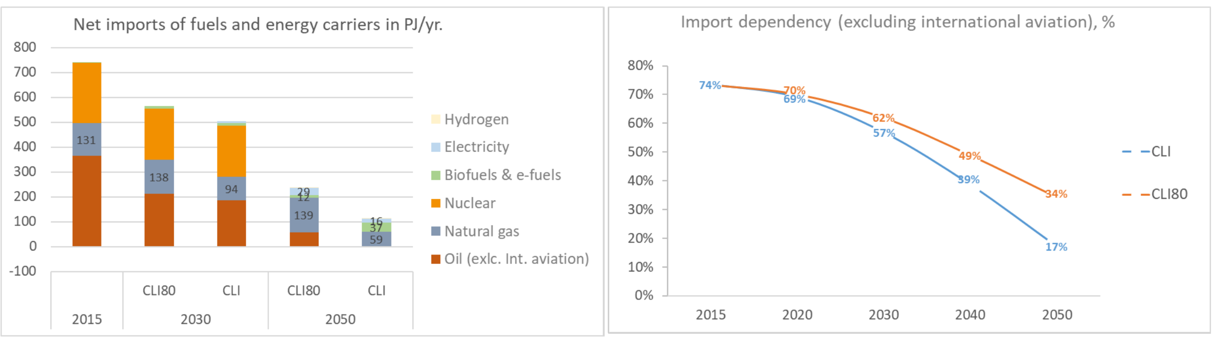
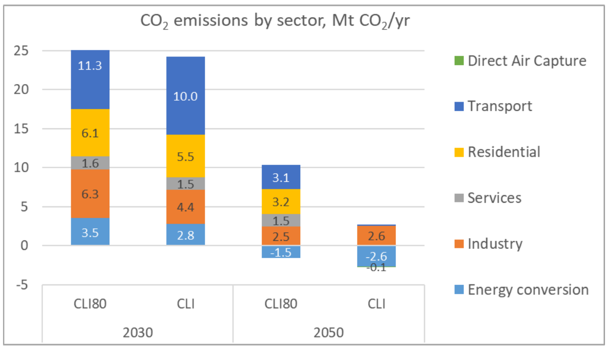


Figure 8.41: *Net imports by fuel and energy carrier (left) and overall import dependency (right)*

8.5.3.5 CO_2 emissions and CC(U)S

The *CLI80* variant achieves about 0.85 Mt CO_2 per capita, which is inline with a global effort of maintaining the increase in average temperature below 2^{o}C by the end of the century. Thus, there are still emissions in transport and buildings, while there is some deployment of BECCS in electricity and hydrogen production, as well CCS in industry, at levels lower than *CLI* (figure 8.42) .



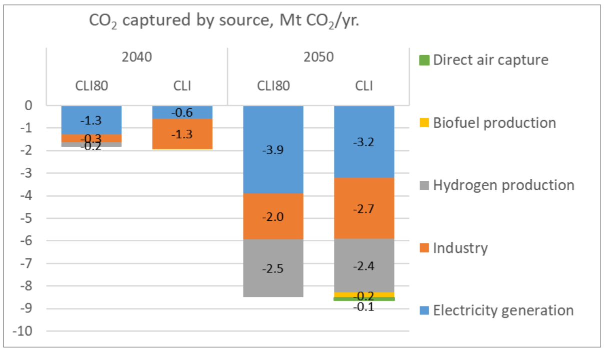


Figure 8.42: *CO_2 emissions and CO_2 captured by sector; on-site CHP emissions are included in end-uses*

8.6 Summary of key insights obtained from the assessment of variants

The assessed variants look at the three main dimensions of the energy trilemma: energy security, energy affordability and innovation. In addition, they also considered the relaxation of targets of the Swiss energy and climate policies, and they assessed the impact of this relaxation on the mitigation pathways. Building on the variants that consider different policies, national and international context, there are some robust findings which are summarised below.

The import dependency in all core scenarios and variants is reduced over time. Even in the variants with higher integration of the Swiss and international markets, the import dependency is five times lower than today. Critical energy carriers to be imported are biofuels and e-fuels, the production of which with domestic resources is constrained due to resource availability or it is too expensive. The variant focusing on energy security indicates a minimum of 3 TWh/yr. of imported biofuels and e-fuels after scaling up their domestic production to the maximum. Electricity imports are needed in winter in all variants, even the ones imposing a net-zero annual import constraint. The electricity imports in winter range between 6 and 8 TWh in 2050, which is close to the quantities imported in the last decade from Switzerland (e.g. in 2016, the electricity imports in winter were around 10 TWh).

The decarbonisation of the demand sectors is also a key element in achieving net-zero emissions by 2050. While the term “decarbonisation” for industry does not necessarily mean zero-emission in 2050, the rest of the stationary sectors, as well as the mobility sector, are fully decarbonised by switching to zero-carbon fuels and implementing energy conservation measures. Even in the variants with good possibilities for CCS deployment, e.g. the ones assuming low costs and high access to international sites for storing CO_2 the end uses of energy are still decarbonised. This outcome suggests that the CCS option is mainly deployed after switching to less carbon-intensive fuels in the demand sectors. In this regard, electricity and synthetic fuels and biofuels play an important role in all sectors, including mobility.

Hydrogen emerges in the Swiss energy system, with electrolysis, SMR/ATR with CCS and wood gasification with CCS being the main production routes. While electrolysis largely depends on the availability of low-cost electricity and the SMR/ATR on imported natural gas, wood gasification with CCS is a cost-effective option in all variants aiming at net-zero emissions in 2050. This is because wood gasification with CCS can deliver negative emissions in the Swiss energy system. Producing hydrogen with this technology is more efficient than generating electricity since the latter case also induces substantial energetic loses in addition to the wood gasification such as related to a gas turbine to generate electricity. The analysis with STEM does not consider carbon dioxide mitigation options related to agriculture and forestry, such as afforestation and biochar production, or to soil management and enhanced weathering. However, we include DACCS and industrial CO_2 mitigation besides energy applications.

In the electricity supply sector, solar PV becomes the dominant technology in the future in all assessed cases. The electricity generation from rooftop solar PV systems ranges from 20 TWh/yr. to 35 TWh/yr. in 2050. The range is sensitive to the growing penetration, the cost of the technology, and the availability of imported electricity as low cross-border prices may represent a barrier to the expansion of domestic solar PV. Aside from solar PV, wind turbines are also part of the solution of all variants. In contrast, electricity from deep geothermal energy emerges only under constrained supply conditions, such as restrictions on imports or limited solar energy expansion.

Exploiting the remaining sustainable potential of domestic bioenergy is of critical importance in achieving the net-zero emissions target in 2050. Not only the domestic manure needs to be mobilised for biogas production, but it is also equally necessary to harvest the remaining forest wood potential. If the use of wood remains at the today levels, it challenges not only the decarbonisation of the demand sectors where wood substitutes fossil fuels, but also the scaling of negative emissions technologies to the levels needed to offset hard to abate emissions from the energy system. A limited expansion of domestic bioenergy resources, manure or wood, would require aggressive deployment of energy conservation measures in the demand sectors.

Overall, achieving the net-zero ambition is technically feasible for Switzerland, under the condition that negative emission technologies are deployed on the order of at least 3 Mt CO_2/yr. and that there is access to international infrastructure for transporting and storing at least 7 Mt CO_2/yr., in total, in the case that sequestration or storage in the Swiss territory is not possible.

Chapter 9

Cost Implications

As indicated in previous chapters, the energy transition is associated with cost implications for several entities in the energy sector. This chapter provides insights regarding the energy system costs of the core scenarios and their variants.

9.1 Definition of energy system costs and policy costs

The entire energy system costs include capital costs (for energy installations such as power plants and energy infrastructure, energy-using equipment, appliances and vehicles), costs related to imports and exports of energy (fuels, electricity, biofuels and synfuels) and direct efficiency investment costs. Capital costs are expressed in annuity payments, calculated based on sector/technology specific discount rates between 2.5% (for energy supply and infrastructure) and 5.5% (for equipment, appliances and vehicles). For transport, it should be noted that we consider the full vehicle cost, including glider costs and drivetrain costs. Direct efficiency investment costs include additional costs for building insulation, double/triple glazing, control systems, energy management, and efficiency-enhancing changes in production processes not accounted under energy capital and fuel/electricity purchase costs. The system costs do not include any disutility costs associated with changed behaviour or the costs related to auctioning of allowances, which lead to corresponding revenues.

STEM computes the stream of annual costs over the entire modelling horizon until 2055, which are aggregated into a single total cost using a social discount rate of 2.5%. Hence, the sector-specific discount rates mentioned above are considered to be the social discount rate plus a sector-specific risk premium. The objective function of STEM is the minimisation of the total energy system cost, in which the annual system costs are aggregated to form the net present value (NPV) over the projection period:

$$NPV = \sum_t \left(1+d\right)^{2010-t} \cdot ANNCOST_t\right)$$

In the above equation, d is the social discount rate, t is the year, and $ANNCOST$ is the annual energy system cost. The year 2010 is the base year, or reference year, of the model.

When it comes to calculating the policy cost, the difference in the annual energy system costs between a baseline scenario and a policy scenario is calculated in each modelling period. In this ex-post calculation, which takes place after the model is solved, we exclude taxes but we include to the cost the subsidies received by energy technologies. The total policy cost is calculated by aggregating these annual differences between the system costs of the two scenarios using a discount rate. Since the chosen discount rate can have a large impact on the policy costs, both undiscounted and discounted policy costs are reported in the figures of this section. The annual streams of energy costs used in calculating the policy costs are discounted by using the social discount rate of 2.5%.

Besides the discount rate, a critical factor influencing the policy cost relates to the level of ambition of the baseline scenario, and how much this ambition deviates from the policy scenario. A baseline that achieves substantial emissions reductions would result in lower policy costs than a more conservative baseline when these two baseline scenarios are contrasted to the same policy scenario.

Another important factor influencing the costs is the assumed technological progress and availability of technologies. If the technological progress is assumed to be higher in the policy scenario than in the baseline scenario, then the resulting policy cost would be lower than the case in which both scenarios assume the same technological progress. In the present analysis, we compare the *MARKETS* and *INNOV* variants that have higher technological progress than in the *BAU* scenario by introducing the corresponding technological progress also to the *BAU* scenario. As such, synthetic *BAU* variants with the same level of market integration and technology learning as in *MARKETS* and *INNOV* respectively are used in order to ensure the scenarios' comparability, as endogenous technology learning effects are beyond the scope of STEM.

It should be also noted that the policy costs reported in this section do not consider feedback with other sectors of the economy or interactions with other countries. This type of analysis requires a general equilibrium framework and it is outside the modelling framework of STEM.

Finally, when reporting the breakdown of the policy costs per sector in the next subsections, the following points should be considered:

- The costs in the end-use sectors include investment and operating expenditures of demand technologies, energy savings, distributed energy supply and storage (e.g. on-site CHPs or rooftop solar PV panels), as well as investment and operating costs related to distribution infrastructures and storage of energy carriers in the end-use sectors, including e.g. fuelling and charging stations in transport for alternative fuels and energy carriers.

- The costs related to fuels and energy carriers are calculated in the upstream sector, and they reported in a separate category together with investment and operating costs in cross-border transmission infrastructures. STEM does not explicitly calculate the "price" of the secondary energy carriers, but rather it accounts for the purchase costs and extraction costs of the primary energy carriers and resources, which are either used for the production of secondary energy carriers or they are directly consumed in the end-use sectors.

- The investment and operating costs included in the electricity sector relate to expenditures of utilities and municipalities at the medium and upper voltage grid levels in assets like hydropower, wind turbines, large cogeneration units and heat plants for district heating, large-scale storages, etc. They also include investment and operating costs related to the electricity grid and district heating network.

- Similarly, the costs related to the other energy conversion sectors (hydrogen, biofuels) relate to investment and operating expenditures in production facilities and large-scale storage.

- Investments and operating costs related to DACCS and to the infrastructure for transporting and storing CO_2 to storage sites in Switzerland and abroad are included in a separate category.

9.2 Policy cost of the core scenarios

The energy transition implies significant transformations across supply and demand sectors. In this section, the economic implications of this transformation, in terms of direct policy costs defined as the difference between the policy scenario and *BAU* are presented and discussed. A comparison of the policy costs between the *CLI* and *EPOL* scenarios is also given. Figure 9.1 presents an overview of the policy costs of *CLI* and *EPOL*, and more insights are provided in the subsequent sections[1].

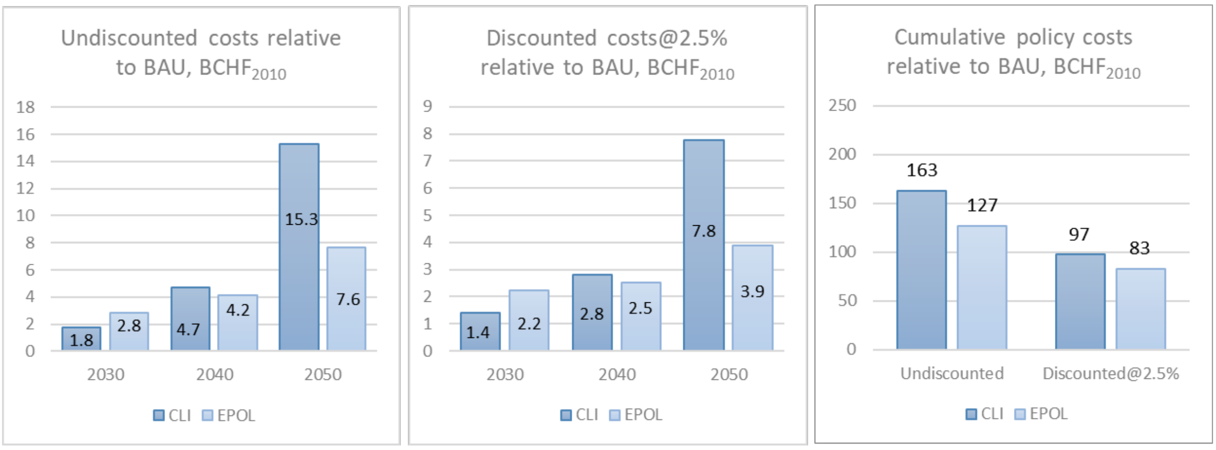


Figure 9.1: *Annual direct cost of the policy in CLI and EPOL,undiscounted (left) and discounted (middle). The figure on the right hand side presents the cumulative costs over the period of 2020 – 2050. For details on the calculation of the cumulative cost please see also section 2.1*

9.2.1 Policy costs in the *CLI* scenario

The policy costs, calculated as the difference between the annual energy system costs in *CLI* and *BAU* scenarios, increase over the entire modelling horizon. As shown in figure 9.2, the investment costs constitute a substantial part of the annual policy costs and the share of capital expenditures in total cost increases over time. In contrast, there are significant cost savings from reduced imports of fossil fuels in *CLI* versus *BAU*, especially over the forthcoming three decades (see also section 4.2).

The development of the costs over the time horizon reveals an exponentially increasing trend with particular high cost towards the end of the projection period. While the model results show an energy system with overall zero CO_2 emissions in 2050, is should be understood that retaining such an energy system or even increasing the climate ambition needs endured investments and expenditures for low carbon energy supply.

The reduction of the energy bill due to the lower consumption of fossil fuels, which consequently translates into policy cost savings, are more significant between 2030 and 2040 compared to the last decade. This is because, by 2030 and 2040, the energy system in the *CLI* scenario has already started

[1]The unit of the costs in the report is CHF_{2010}. 1 CHF_{2019} is approximately 0.98 CHF_{2010}, due to the negative GDP inflation in the last years

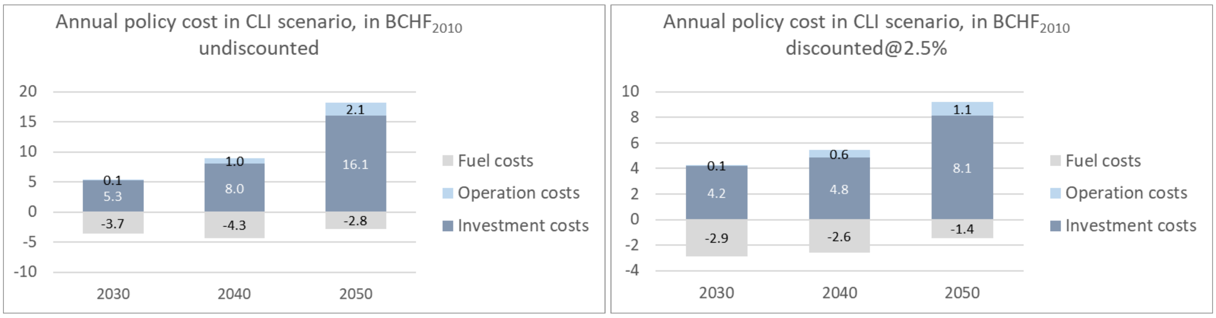


Figure 9.2: *Annual direct cost of the policy in the CLI scenario, calculated as the difference in the annual energy system cost between CLI and BAU, undiscounted (left) and discounted (right)*

the transition to decarbonisation, while in the *BAU* scenario fossil fuels continue to have a large share over a longer timeframe. On the contrary, in 2050, fossil fuel consumption in the *BAU* scenario declines substantially compared to 2040, and, consequently, the difference in fuel expenditures compared to *CLI* becomes lower.

The decomposition of the policy cost per sector (figure 9.3) shows that the transport and residential sectors bear the highest burden among all. As stated in the introduction of this section, the sectoral policy costs refer only to costs related to investment and operating expenditures, as fuel costs are reported in the upstream sector together with costs related to investment and operation of cross-border infrastructures. Hence, the costs in the end-use sectors include investments and operating expenditures to decentralised energy supply and storages as well as costs relating to the investment and operation of the distribution infrastructure for providing energy carriers to the consumers. The costs related to the electricity sector include investment and operating costs for assets in the medium and upper grid levels, such as hydropower or large cogeneration units and heat plants for district heating, as well as costs related to the investment and operation of the electricity and district heating networks. The "Other" sector shown in figure 9.2 mainly includes expenditures related to the investment and operation of DACCS as well as in the infrastructure for transporting and storing CO_2 to storage sites in Switzerland and abroad.

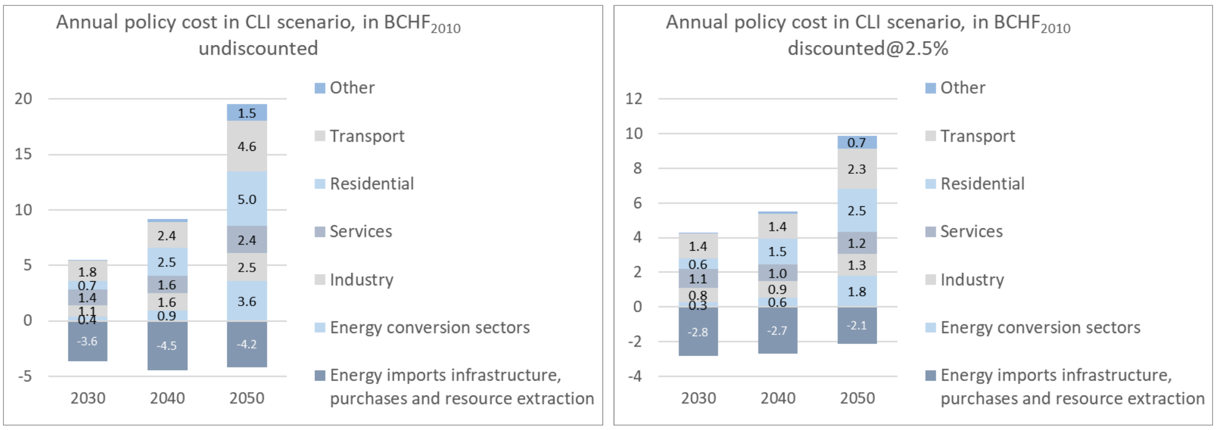


Figure 9.3: *Annual direct cost of the policy in CLI scenario per sector, calculated as the difference in the annual energy system cost between CLI and BAU, undiscounted (left) and discounted (right)*

Expressed as a percentage of GDP, the annual policy costs in *CLI* increase over time from 0.2% in 2030 to 1.5% in 2050. In industry the annual costs for the transition to net-zero emissions in 2050 increase from 0.5% in 2030 to 1.0% in 2050, when these are expressed as a percentage of the gross value added in the sector. For the services sectors, the annual policy costs as a percentage of the gross value added in services increase from 0.2% in 2030 to 0.3% in 2050.

The cumulative discounted investment and operation costs in the residential sector amount to about 37 billion CHF_{2010} over the period of 2020-2050, which implies an average cumulative cost per person of about 3500 CHF_{2010} to decarbonise the residential sector over these 30 years. In transport, the cumulative discounted investment and operating costs from 2020 to 2050 are of a similar magnitude, around 48 billion CHF_{2010}. In industry and services, the incremental, cumulative discounted investment and operating expenditures to achieve the net-zero ambition amount to 31 and 29 billion CHF_{2010}, respectively. The reduction in the import dependency in *CLI* compared to *BAU* results in cost savings related to the investment and operation of cross border infrastructure (grids, pipelines) and the purchase of imported fuels and energy carriers. The discounted cumulative gains are about 72 billion CHF_{2010} over the period of 2020-2050. Overall, the total cumulative discounted policy cost between 2020 and 2050 amounts to 97 billion CHF_{2010}.

As stated above, the largest part of the policy costs in *CLI* is represented by investment expenditures. Figure 9.4 shows the capital outlays for the main sectors of the energy system. In this context, the investment in the demand sectors represents more than 90% of the cumulative investment requirements over the period 2020-2050, including expenditures for on-site decentralised electricity and heat supply, such as CHP in buildings, rooftop solar PV systems, as well as distributed storage, EV charging infrastructure and hydrogen fuel stations. Thus, the investments in the supply side represent approximately 10% of the total cumulative investment expenditure over the period of 2020-2050.

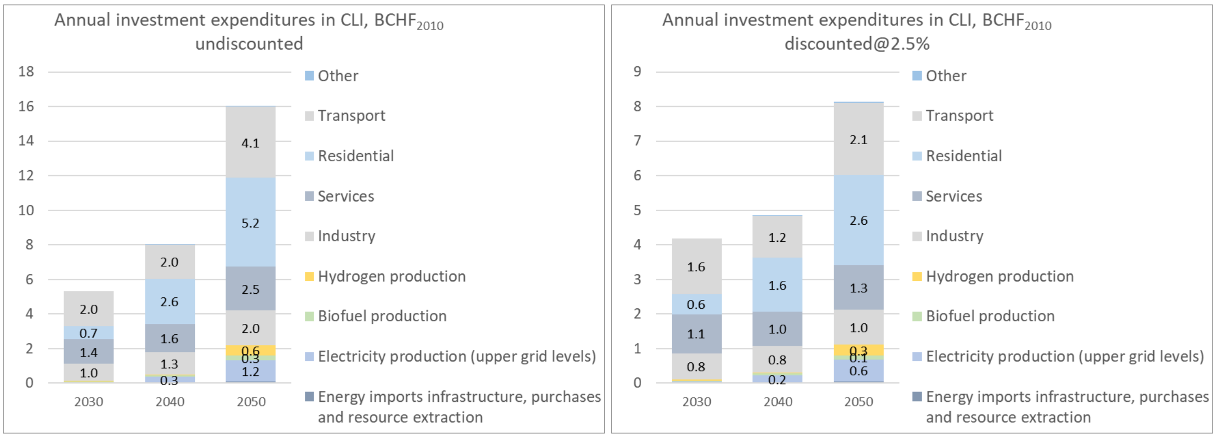


Figure 9.4: *Annual investment expenditures per sector, calculated as the difference between CLI and BAU, undiscounted (left) and discounted (right)*

The investment expenditures in the stationary demand sectors account for two-thirds of the total cumulative capital outlays between 2020 and 2050, of which the residential sector constitutes the largest share. The incremental investment expenditures in services and industry sectors are higher in the period until 2030. Still, afterwards, they become almost half in the order of magnitude compared to the residential sector. This is attributable to the fact that the energy transition to a low-carbon energy system is faster in industrial and commercial buildings and facilities, due to economics of scale, compared to the residential sector. The investment in the residential sector become larger after 2040, as the sector needs to deliver large emissions reductions compared to the *BAU scenario*.

Moreover, in the *BAU* scenario, the services and industry sectors undergo a transition to less carbon-intensive activities by 2050, as discussed in sections 3.2 and 3.3, and this reduces the needs for additional investment in the *CLI* scenario to some extent. The transport sector is largely dominated by investments in alternative drivetrains in passenger cars. However, the analysis does not consider shared mobility schemes that would increase occupancy rates and reduce the number of required vehicles, which could generate positive implications by lowering the transition costs.

About 60% of the supply side investments are directed to electricity generation, with the rest being shared between the production of hydrogen, biofuels and synthetic fuels. Hydrogen production and production of synthetic fuels become an important component of the investment costs, mainly in the last decade of the projection horizon.

9.2.2 Policy costs in the *EPOL* scenario

The *EPOL* scenario implements the renewable and efficiency targets envisaged in the Swiss Energy Strategy, without imposing a concrete emissions reduction target. The breakdown of the annual policy costs by type of expenditure is given in Figure 9.5. There is a dominance of the investment costs, mainly driven by investments in more efficient technologies, energy conservation and building renovation measures. The lower import dependency driven by the efficiency gains in *EPOL* results in a reduction of the fuel costs compared to the *BAU* scenario. In *EPOL*, the overall cumulative discounted costs amount to about 83 billion CHF_{2010}, i.e. about 14 billion less than the policy costs attained in the *CLI* scenario. When expressing the annual policy costs as a percentage of GDP, they increase from 0.3% in 2030 to 0.7% in 2050.

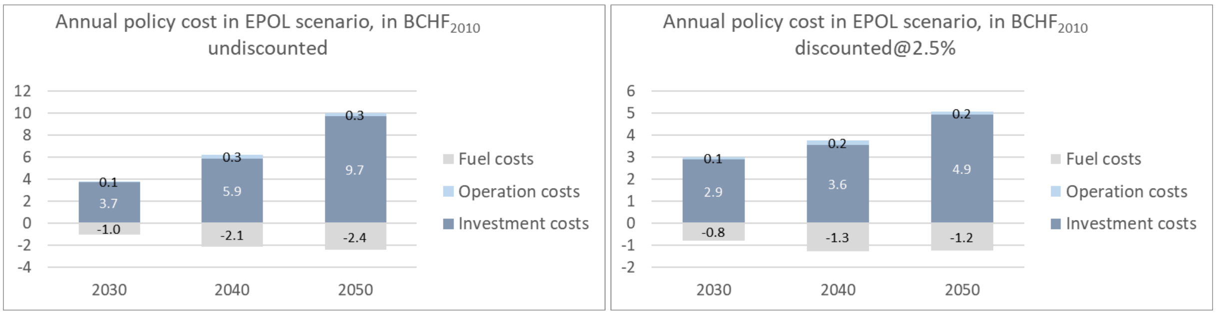


Figure 9.5: *Annual direct cost of the policy in EPOL scenario, calculated as the difference in the annual energy system cost between EPOL and BAU, undiscounted (left) and discounted (right)*

Figure 9.6 shows the decomposition of the policy costs per sector. In *EPOL*, the transport sector has the largest share in the costs to achieve the energy transition, followed by the residential sector. The large share of transport in the policy costs is attributable to the overall constraint in the electricity consumption per capita implemented in *EPOL*, which hinders the further electrification of the sector and leads to the deployment of (the more expensive) fuel cell vehicles to meet the overall efficiency targets.

The cumulative discounted policy costs in the residential sector (investment and operation costs only) are about 28 billion CHF_{2010} from 2020 to 2050. In transport the cumulative discounted policy costs, also related to investment and operating expenditures, amount to about 35 billion CHF_{2010} for the same period. The cumulative discounted reduction of fuel costs (purchases of imported energy carriers plus investment and operating expenditures in cross-border transmission infrastructure) in

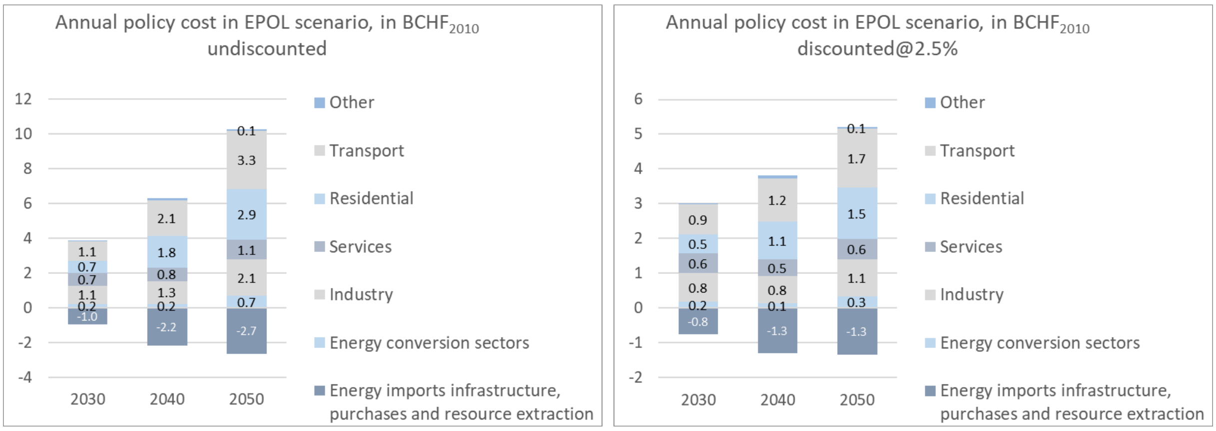


Figure 9.6: *Annual direct cost of the policy in EPOL scenario per sector, calculated as the difference in the annual energy system cost between EPOL and BAU, undiscounted (left) and discounted (right)*

EPOL compared to the *BAU* scenario are about 29 billion CHF_{2010}.

Similar to *CLI*, also in *EPOL*, the investment expenditures constitute the largest component of the policy costs. Figure 9.7 shows the cost decomposition by sector. The demand sectors have the largest share, with about 96% of the total cumulative investment from 2020 to 2050. Transport absorbs about two-thirds of the capital outlays in the demand sectors. The investments in the supply sector account for only 4% of the total, with the electricity sector representing more than two-thirds of the capital outlays directed to energy conversion. The remaining one-third is shared between hydrogen, synthetic fuels and biofuels production. Compared to *CLI* the investments in the supply sector are almost the half of the investments in *EPOL*. This is primarily because of the lower electricity production in *EPOL* than in *CLI*, over the period of 2020-2050, due to the implementation of the indicative target in the Swiss Energy Strategy regarding the reduction of the electricity consumption per capita.

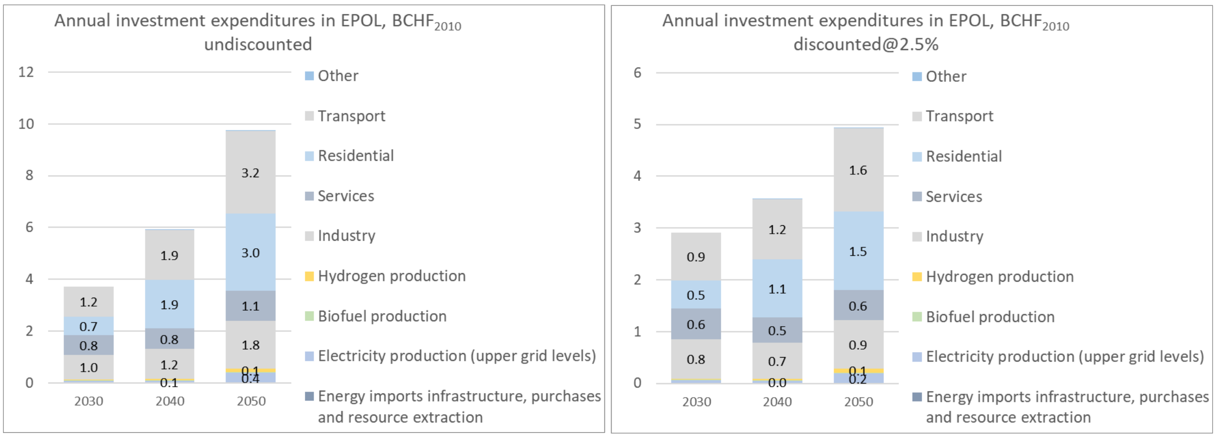


Figure 9.7: *Annual investment expenditures per sector, calculated as the difference between CLI and BAU, undiscounted (left) and discounted (right)*

9.2.3 Comparison of the policy costs in *EPOL* and *CLI* scenarios

The *CLI* scenario does not directly build on the developments of *EPOL*. Their comparison should consider that *CLI* reflects a normative scenario, while *EPOL* an explorative scenario when it comes to decarbonisation targets.

Figure 9.8 presents the difference in the costs between *CLI* and *EPOL*. The cumulative discounted additional costs in the *CLI* scenario compared to *EPOL* are about 14 billion CHF_{2010} throughout the timeframe 2020 – 2050. In the period until 2030, the *CLI* scenario displays lower costs than *EPOL* due to the reduction of import dependency and reduced imports of fossil fuels, as the energy system moves towards decarbonisation via additional energy conservation measures and electrification in the demand sectors. Thus, despite the similar trajectory that *EPOL* and *CLI* follow until 2040 in terms of total final energy consumption, the decarbonisation policies of *CLI* increase the savings achieved from the lower penetration of fossil fuels in the energy mix. However, in the post-2040 period, the energy system cost in *CLI* is substantially higher than *EPOL* as the investment needs in low-carbon energy technologies, and efficiency measures increase with the climate change mitigation ambition.

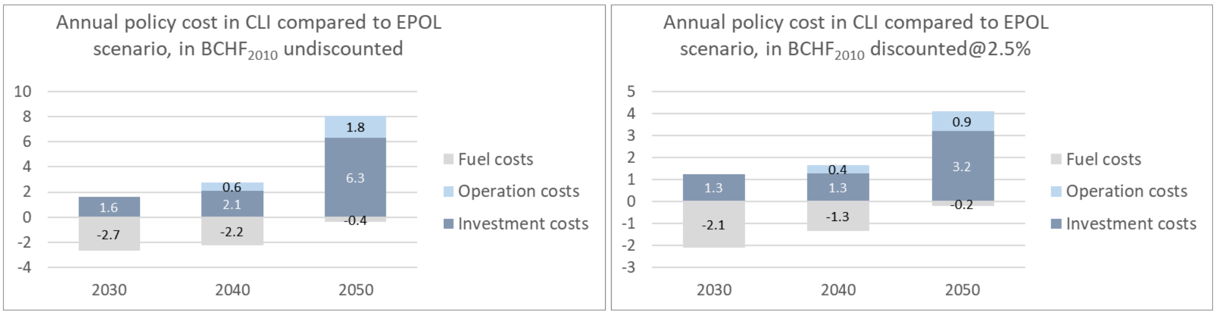


Figure 9.8: *Annual direct cost of the policy in the CLI scenario, calculated as the difference in the annual energy system cost between CLI and EPOL, undiscounted (left) and discounted (right)*

As shown in figure 9.9 much of the incremental investment occurring in the last decade in *CLI* compared to *EPOL* is almost equally distributed between investments in hydrogen and synthetic fuels and biofuels production, and investment in the residential and services sectors. There is also an additional investment in *CLI* in the transport sector to further decarbonise mainly the long-distance transport with the penetration of fuel cell vehicles. Also, a substantial part of the incremental investment in *CLI* is related to infrastructure for CO_2 transport and storage, which is deployed at a higher degree than in *EPOL*. On the contrary, industry does not display much additional investment expenditure in *CLI* compared to the *EPOL* scenario, and the incremental capital outlays in the industrial sectors are mainly directed to the deployment of CCS in the cement industry.

Finally looking at the average cost of mitigation over the period of 2020 to 2050, in *EPOL* this is around 590 CHF_{2010}/tCO_2 while in the *CLI* scenario it is around 440 CHF_{2010}/tCO_2 . The lower mitigation cost of *CLI* related to *EPOL* is due to the better economic performance of *CLI* in the period until 2040, as *CLI* reaps the benefits not only of the energy efficiency that lowers the energy consumption but also the shift away from imported fossil fuels. This outcome indicates that energy efficiency and climate policies need to be coordinated to achieve the net-zero emissions target at the lowest cost. Moreover, it signals the inefficiency in the energy system arising by the implementation of the reduction of the electricity consumption per capita in *EPOL*.

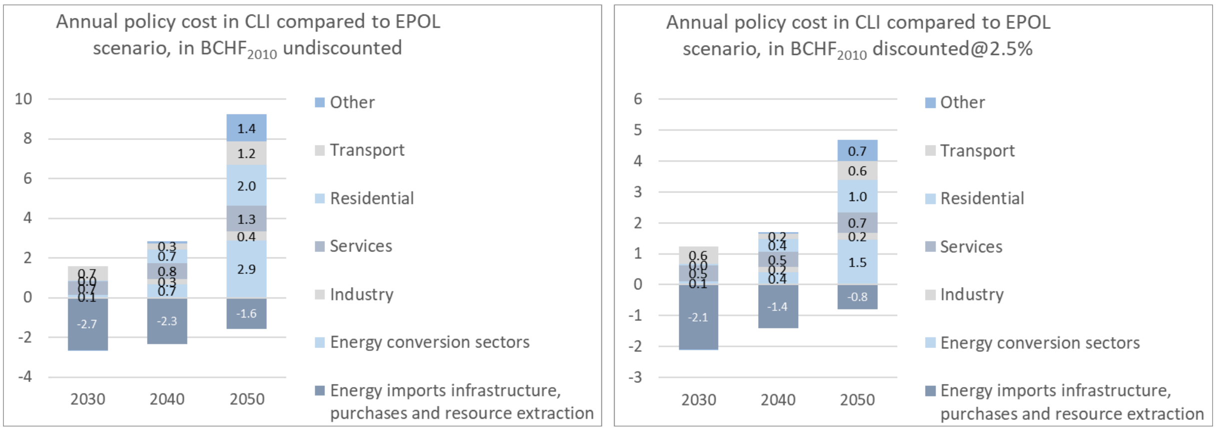


Figure 9.9: *Annual direct cost of the policy in CLI scenario per sector, calculated as the difference in the annual energy system cost between CLI and EPOL, undiscounted (left) and discounted (right)*

9.3 Policy costs: insights from the variants

The policy costs of the transition to net-zero emission in 2050 largely differ among the variants of *CLI*, and they mainly depend on the availability of decarbonisation options and resources assumed in the context of each variant. In this regard, the variants with the most restrictions related to the availability of imported zero-carbon energy carriers or related to the exploitation of the domestic renewables resources display higher policy costs compared to variants that assume higher access to renewable resources or a higher integration of the energy markets. The same also holds for technology progress. An overview of the cumulative discounted policy costs from 2020 to 2050 that are obtained across all variants is shown in figure 9.10.

The ***ANTI*** variant displays very high additional costs compared to the other variants. The combined restriction of imports and the limited exploitation of the remaining sustainable potential, constitute the key factors for the high policy costs. Although there are cost savings in the fuel costs due to the lower import dependency and consumption of fossil fuels in the energy mix, these are largely offset by the massive investment expenditures mainly directed to the energy conservation and building renovation measures needed to reduce the final energy consumption and the emissions, in a context of limited access to zero-carbon energy carriers. The annual policy costs increase significantly in the last two decades of the projection horizon, by when the level of ambition also increases, and resource scarcity becomes an issue.

The ***SECUR*** variant allows much higher exploitation of the domestic renewable potential resources compared to *ANTI*, while it imposes a more stringent constraint on import dependency. However, the cumulative policy costs in *SECUR* are second-highest after *ANTI*, which signals the critical importance of exploiting the domestic renewable potential and gaining access to the international markets. Capital expenditures dominate the costs to deploy solar PV systems in the stationary sectors and establishing P2X pathways for the production of synthetic fuels, in a context of limited access to imports. *SECUR* is an expensive mitigation pathway, which also implies that while relying on domestic resources is technically feasible, it is not necessarily the most cost-effective option. Access to international markets of zero-carbon fuels and energy carriers is beneficial to a more affordable energy transition. Or, viewed another way, deploying more domestic resources for the sake of reduced import dependency translates into a non-neglectable security premium.

Figure 9.10: *Annual direct cost of the policy in the core scenarios CLI and EPOL, as well as in their variants, calculated as a difference from the energy systems cost in BAU, undiscounted (top) and discounted (bottom). The columns with an * imply that the corresponding variant from CLI is contrasted against the corresponding variant of BAU, e.g. the MARKETS* is the policy cost of the MARKETS variant of CLI which is compared with a MARKETS-compatible variant of BAU*

The ***MARKETS*** variant assumes not only high access to domestic renewables resources as the *SECUR* variant, but it also considers a higher integration of the Swiss and international energy markets with the increased availability of imported biofuels, hydrogen and synthetic fuels. Compared to *SECUR*, the cumulative transition costs in *MARKETS* are lower by 64% from 2020 to 2050, when calculated against a variant of *BAU* that also assumes a similar level of market integration as in *MARKETS*. This outcome highlights the need for securing access to international markets for zero-carbon energy carriers. Since the penetration of biofuels and synthetic e-fuels in the Swiss energy system is crucial to decarbonise the long-distance transport sector, the integration of the energy markets should consider the new emerging energy carriers required for decarbonisation and expand beyond the integration of the Swiss and European electricity markets.

The ***INNOV*** variant displays the lowest costs among all the deep decarbonisation pathways assessed in the current analysis. The increased learning of new technologies, the increased access to renewable potentials and the better integration and coordination of the energy markets can result in policy costs, which are about 40% lower than in the core *CLI* scenario, when calculated against a variant of *BAU* that also assumes a similar level of innovation and market integration as in *INNOV*. However, the realisation of the *INNOV* variant would require an internationally coordinated effort regarding the R&D investment in low carbon technologies, as well as an international context that delivers strong long-term price signals to the investors to mitigate their risk in investing in options facilitating decarbonisation.

The ***CLI100*** variant displays lower policy costs than in *CLI*, as the transition of the Swiss energy system is slower, with the deployment of domestic options for decarbonisation lag the deployment seen in the *CLI* scenario. As a result, the *CLI100* scenario relies more on imported energy carriers than in *CLI*, and as such, it reports costs at a level between the *CLI* and the *MARKETS* variant.

Finally, the ***CLI80*** variant fails to achieve the net-zero ambition in 2050, and it is mostly on a track for achieving the 2^{o}C temperature target. In this regard, the policy costs of *CLI80* can be contrasted to the policy costs of *CLI100* and gain insights related to the incremental effort needed for moving from the 2^{o}C to 1.5^{o}C mitigation pathway. As shown in figure 9.10, the undiscounted policy costs to achieve the net-zero ambition can be six times higher than the costs required to stay at a trajectory that limits the temperature increase above 2^{o}C in 2100.

Figure 9.10 also displays the policy costs of the ***EPOL-E*** variant, which can be compared with the *EPOL* core scenario. The variant lifts the constraint in the electricity consumption per capita of the *EPOL* scenario, which results in about 5% lower cumulative discounted policy costs over the period of 2020 – 2050. This outcome suggests that introducing a target in the overall electricity consumption can induce some inefficiencies in the energy system, especially when electricity is a key energy carrier to achieve energy savings in the demand sectors.

9.4 Key insights from the policy cost implications of the transition

The analysis of the energy transition's cost implications provided a number of key insights regarding the main drivers affecting an affordable and secure deep decarbonisation pathway. These can be grouped into three main pillars.

The first pillar is the exploitation of sustainable domestic renewable potential. This includes not only the solar PV systems but also bioenergy, wind and geothermal. Of critical importance is securing access to the sustainable bioenergy potential and ensuring that this would be used to deliver negative emissions.

The second pillar is the integration of energy markets, especially those involving the trading of new energy carriers, such as hydrogen and synthetic fuels. While technically, it is feasible to develop domestic synthetic fuels and e-fuels, it is not always the most cost-effective option.

The third pillar is the technology innovation and R&D expenditures worldwide to low carbon technologies in order to reduce their costs and improve the overall performance. The transition to a low carbon energy economy can be greatly accelerated by technological progress and circular economy practices that reduce the cost of materials, and, consequently, the renovation costs and the costs of implementing energy conservation schemes. Such technological progress and innovation would be further supported if backed up with global and coordinated climate action.

9.5 Role of finance

The financial sector and sustainable finance would play a key role in enabling the energy transition towards a decarbonised and innovative system. As the analysis shows, there is a large gap between existing investment and required capital to achieve the transition. The financial sector would need to enable the uptake of decarbonisation technologies and infrastructure, by mitigating losses for financial institutions and avoiding the generation of stranded assets. In this regard, capital needs to redirected towards green and sustainable investments by integrating physical risks and intangible environmental, societal and governance factors in asset pricing (EC, 2018).

A supportive policy and regulatory framework can foster financial innovation. Government and financial institutions can work together to put in place the conditions to promote financial innovation, which would avoid high funding costs and financial constraints in the transition (World Economic Forum, 2020). For example, better debt financing terms helped in lowering the generation costs for new offshore wind in Europe by nearly 15% in the past five years (IEA, 2020).

Some innovative financial tools that can direct capital towards cleaner and sustainable technologies include sustainable and green bonds, guarantee mechanisms, insurances, and blended finance (Majid, 2020). A sustainable bond applies to a project that contributes to sustainability and climate. It has typically a fixed income return backed up by project assets or the issuing entities' balance sheet. A guarantee mechanism is usually offered by a third party to hedge a clean and sustainable project, which typically involves a non-mature technology, against default and loss of revenue. Insurance companies can also play a major role by hedging inherent project risks, rationalising the cost of funds, and contributing towards project implementation. Finally, blended finance is a combination of commercial funding by investors and concessional funding providing by development partners. It provides comfort to private investors and addresses concerns around markets and project risks.

In fact, private investors would have to account for the bulk of investment needs. Despite the significant increase in absolute terms in recent years (IEA, 2020), and especially in some sub-sectors such as energy efficiency and renewables, still, the investment in low-carbon technologies has a small share in the investors' assets. In this regard, regulatory measures and financial support at a national level will continue to be necessary to stimulate sustainable investments and direct capital to the low-carbon transition. Institutional investors have a large share in the private investment expenditure. They have a risk-averse profile opting for mature technologies with low operational risk. For example, solar PV is such a technology that offers a good alignment between the financial stances of the institutional investors and the need for sustainable investments.

However, to systematically direct capital towards the energy transition, three conditions need to be present within the financial markets (EC, 2018): a) investors need to consistently be given the option of investing in zero or low carbon assets; b) climate and environmental risks should be mainstreamed in economic and financial decision-making and assets' evaluation, such that markets and credit risk agencies price climate risks, and borrowing conditions adjust to favour sustainable investment; and c) companies and financial institutions need to think long-term and be transparent about their operations.

To this end, providing clarity and a robust investment framework to investors should be one of the decarbonisation strategy goals to avoid stranded assets and facilitate the transition. Policy needs to deliver coherent and timely signals to the market, supported by long-term plans.

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