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Seasonal energy storage

Current state of knowledge, research needs, and recommendations for action

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Zusammenfassung

Die Energietransformation in der Schweiz steht vor einer zentralen Herausforderung: der saisonalen Diskrepanz zwischen Energieangebot und -nachfrage. Während im Sommer – insbesondere durch Photovoltaik und Wasserkraft – ein Energieüberschuss absehbar ist, kann der deutliche Anstieg des Elektrizitätsbedarfs im Winter infolge der Elektrifizierung unter anderem des Wärme- und Mobilitätssektors durch die laufende Produktion voraussichtlich nicht abgedeckt werden. Eine naheliegende Strategie zur Entschärfung dieser Diskrepanz ist die saisonale Energiespeicherung. Sie kann nicht nur das Ungleichgewicht zwischen Angebot und Nachfrage mindern, sondern auch die Integration erneuerbarer Energien fördern und die Resilienz und Versorgungssicherheit des Energiesystems stärken.

Für die saisonale Speicherung kommen verschiedene Technologien infrage. Die Speicherwasserkraft wird auch in Zukunft eine zentrale Rolle bei der Elektrizitätsversorgung im Winter spielen und bleibt ein bewährtes Element der Schweizer Energieinfrastruktur. Daneben bieten Wärmespeicher mehrere Möglichkeiten: Überschüssige Abwärme aus Kehrichtverbrennungsanlagen oder Rechenzentren im Sommer lässt sich im Boden oder anderen Medien speichern und im Winter nutzen. Auch überschüssiger Sommerstrom kann in Form von Wärme so gespeichert werden. Dies ist insbesondere in Kombination mit Raumkühlung interessant und kann dazu beitragen, den Elektrizitätsbedarf von Wärmepumpen in den Wintermonaten zu reduzieren. Biomasse eröffnet ebenfalls Optionen für die saisonale Speicherung, entweder durch die Herstellung speicherbarer Energieträger wie Biomethan oder durch direkte Lagerung in fester Form, etwa von Holz. Auch mit Strom hergestellte gasförmige oder flüssige Energieträger lassen sich beispielsweise in Felskavernen oder Treibstofflagern saisonal speichern.

Die Speicherung geeigneter Energieträger ist in vielen Fällen vergleichsweise unkompliziert. Das Zusammenspiel mit anderen Elementen des Energiesystems erweist sich jedoch als deutlich komplexer. Eine besondere Herausforderung ist die Herstellung speicherbarer Energieträger, wie etwa die Erzeugung chemischer Energieträger mit Strom. Solche Prozesse sind in der Schweiz häufig nur mit relativ niedrigen Auslastungsfaktoren betreibbar, was zu hohen Produktionskosten führt. Auch bei der Nutzung von Biomasse bestehen strukturelle Einschränkungen und ein begrenztes Potenzial. Neben der Reduzierung der saisonalen Diskrepanz können saisonale Speicher jedoch auch weitere Vorteile bieten, etwa bei der Bewältigung kurzfristiger Systemdynamiken durch die Aufnahme von Stromspitzen oder die Abfederung von Lastspitzen in Wärmenetzen.

Die Erzeugung speicherbarer Energieträger in der Schweiz steht zudem oft im direkten Wettbewerb mit Importen. Aufgrund teilweise besserer Produktionsvoraussetzungen im Ausland sind dort höhere Auslastungsfaktoren möglich, so dass importierte Energieträger in vielen Fällen kostengünstiger sein dürften als die lokale Produktion. Zwar geht mit der Nutzung importierter Energieträger eine gewisse Abhängigkeit vom Ausland einher, doch könnten grosse Speicher deren Zwischenlagerung ermöglichen und so zur Stärkung der Versorgungssicherheit und Resilienz des Schweizer Energiesystems beitragen.

Ein zentraler Erfolgsfaktor für die tatsächliche Umsetzung saisonaler Speicherung in der Schweiz liegt jedoch nicht allein in der technologischen Machbarkeit, sondern vor allem in den nicht-technischen Rahmenbedingungen. Besonders entscheidend wird die wirtschaftliche Attraktivität dieser Speicherlösungen sein. Hier spielt die Ausgestaltung des Energiemarkts eine Schlüsselrolle. Ein Marktumfeld mit klar differenzierten saisonalen Preissignalen sowie verlässlichen Rahmenbedingungen für langfristige Investitionen könnten dazu beitragen, Wirtschaftlichkeit und Investitionssicherheit zu verbessern. Ergänzend wäre die Einführung eines spezifischen Markts für Energie bzw. Stromreserven denkbar, in dem Resilienz als handelbares Gut etabliert wird. Dies könnte zusätzliche Anreize für Investitionen schaffen.

Über die wirtschaftlichen Aspekte hinaus stellen sich weiter auch regulatorische und gesellschaftliche Fragen. Bei Wärmespeichern etwa sind raumplanerische Voraussetzungen bislang unzureichend definiert. Für den Aufbau einer zukünftigen Wasserstoffinfrastruktur ist zudem eine enge Abstimmung mit den rechtlichen Rahmenbedingungen der Nachbarländer notwendig. Nicht zuletzt hängt die Realisierung solcher Speicherprojekte stark von der gesellschaftlichen Akzeptanz ab. Während die bestehende Wasserkraft in der Bevölkerung weitgehend anerkannt ist, ist über die Akzeptanz neuer Speichertechnologien wie Felskavernen oder grosser Wärmespeicher bisher wenig bekannt.

Für die Integration saisonaler Speicher in das Schweizer Energiesystem sind daher noch einige zentrale Fragen offen, die im zweiten Teil dieses Berichts identifiziert und systematisch aufgelistet wurden.

Résumé

La transition énergétique en Suisse est confrontée à un défi central : la discordance saisonnière entre l'offre et la demande d'énergie. Alors qu'un excédent énergétique – principalement issu du photovoltaïque et de l'hydroélectricité – est attendu en été, la forte hausse de la demande hivernale en électricité, liée à l'électrification des secteurs du chauffage et de la mobilité ainsi qu'à la croissance rapide des centres de données, ne peut être couverte par la production continue. Une stratégie prometteuse pour atténuer ce déséquilibre est le stockage saisonnier de l'énergie. Il permet non seulement d'harmoniser l'offre et la demande, mais aussi de favoriser l'intégration des énergies renouvelables et de renforcer la résilience et la sécurité d'approvisionnement du système énergétique.

Plusieurs technologies se prêtent à ce stockage saisonnier. L'hydroélectricité de pompage continuera de jouer un rôle central dans l'approvisionnement hivernal en électricité et constitue un élément éprouvé de l'infrastructure énergétique suisse. Les stockages thermiques offrent également de nombreuses possibilités : la chaleur excédentaire issue des usines d'incinération des déchets ou des centres de données peut être stockée dans le sol ou d'autres matériaux pendant l'été, puis utilisée en hiver. De même, l'électricité excédentaire produite en été peut être transformée en chaleur et stockée – ce qui s'avère particulièrement intéressant en lien avec la climatisation estivale et permet de réduire les besoins électriques des pompes à chaleur durant l'hiver. La biomasse ouvre également des perspectives de stockage saisonnier, soit par la production de vecteurs énergétiques stockables comme le biométhane, soit par le stockage direct sous forme solide, par exemple de bois. Des vecteurs énergétiques produits à partir d'électricité – tels que l'hydrogène ou les carburants de synthèse – peuvent aussi être stockés de manière saisonnière, par exemple dans des cavernes rocheuses ou des dépôts de carburant.

Le stockage des sources d'énergie appropriées est souvent relativement simple. L'interaction avec d'autres éléments du système énergétique s'avère toutefois nettement plus complexe. La production de sources d'énergie stockables, telles que les sources d'énergie chimiques à partir d'électricité, représente un défi particulier. En Suisse, ces processus ne peuvent souvent être exploités qu'avec des taux d'utilisation relativement faibles, ce qui entraîne des coûts de production élevés. L'utilisation de la biomasse est également soumise à des contraintes structurelles et présente un potentiel limité. Outre la réduction des écarts saisonniers, les stockages saisonniers peuvent toutefois offrir d'autres avantages, par exemple en permettant de gérer les dynamiques à court terme du système grâce à l'absorption des pics d'électricité ou à l'amortissement des pics de charge dans les réseaux de chaleur.

La production de vecteurs énergétiques stockables en Suisse est aussi souvent en concurrence directe avec les importations. À l'étranger, de meilleures conditions de production permettent d'atteindre des taux d'utilisation plus élevés, ce qui rend les vecteurs importés souvent bien moins coûteux que la production locale. Bien que le recours à ces vecteurs engendre une certaine dépendance, de grands systèmes de stockage permettraient leur entreposage intermédiaire, renforçant ainsi la sécurité d'approvisionnement et la résilience du système énergétique suisse.

La réussite de la mise en œuvre du stockage saisonnier en Suisse dépend cependant moins de sa faisabilité technique que des conditions-cadres non techniques. L'attractivité économique sera particulièrement déterminante, et la conception du marché de l'énergie jouera un rôle clé. Un environnement de marché doté de signaux de prix saisonniers clairs et de conditions fiables pour les investissements à long terme pourrait améliorer la rentabilité et la sécurité des investissements. En complément, la création d'un marché spécifique pour les réserves d'énergie ou d'électricité, dans lequel la résilience serait un bien échangeable, pourrait stimuler les investissements.

Au-delà des aspects économiques, des questions réglementaires et sociétales se posent. Pour les stockages thermiques, les bases d'aménagement du territoire – notamment souterraines – sont encore insuffisamment définies. La mise en place d'une infrastructure hydrogène future nécessite en outre une coordination étroite avec les cadres juridiques des pays voisins.

Enfin, la concrétisation de tels projets de stockage dépend largement de l'acceptation sociale. Si l'hydroélectricité bénéficie d'un large soutien, on sait encore peu de choses sur l'acceptation des nouvelles technologies de stockage, comme les cavernes rocheuses ou les grands réservoirs thermiques.

Ainsi, plusieurs questions clés restent ouvertes concernant l'intégration du stockage saisonnier dans le système énergétique suisse. Elles sont identifiées et systématiquement énumérées dans la seconde partie de ce rapport.

Summary

The Swiss energy transition faces a major challenge: the seasonal mismatch between energy supply and demand. While a surplus of energy — mainly from photovoltaics and hydropower — is expected in summer, the growing winter demand for electricity due to electrification of the heating and mobility sectors, as well as rapidly expanding data centres, cannot be met by continuous production alone. A promising strategy to mitigate this imbalance is seasonal energy storage. It not only helps to match supply and demand but also facilitates the integration of renewable energy and strengthens the resilience and supply security of the energy system.

Various technologies are suitable for seasonal storage. Hydropower storage will continue to play a central role in winter electricity supply and remains a key element of Switzerland's energy infrastructure. Additionally, thermal storage offers multiple opportunities: Excess heat from waste incineration plants or data centres can be stored underground or in other media during summer and used in winter. Similarly, surplus electricity generated in summer can be converted into heat and stored, particularly in combination with space cooling, which reduces wintertime electricity demand for heat pumps. Biomass also offers options, either through the production of storable energy carriers like biomethane or by storing solid biomass such as wood. Electricity-based energy carriers — such as hydrogen or synthetic fuels — can be stored seasonally in rock caverns or fuel depots.

While storing suitable energy carriers is often relatively straightforward, integrating them with the broader energy system is significantly more complex. One major challenge is the production of storable energy carriers — especially chemical carriers generated from electricity. In Switzerland, these processes tend to operate with relatively low capacity factors due to the irregular availability of renewable energy, resulting in high production costs. Biomass also faces structural constraints: its widely dispersed availability limits the size of potential plants, hindering economies of scale and cost efficiency. In addition to balancing seasonal supply-demand mismatches, seasonal storage can support the energy system in other ways — such as buffering short-term dynamics. For example, they can absorb power peaks to relieve the grid or mitigate peak loads in thermal networks.

Producing storable energy carriers in Switzerland often competes directly with imports. Since other countries may have better production conditions, higher capacity factors can be achieved abroad, making imported carriers potentially cheaper than domestic production. Although using imported energy carriers involves a certain dependency, large-scale storage systems could allow intermediate storage, thus enhancing supply security and system resilience.

Ultimately, the success of seasonal storage in Switzerland depends not only on technical feasibility but also on non-technical conditions. Economic attractiveness will be particularly crucial, with energy market design playing a key role. A market environment featuring clear seasonal price signals and reliable long-term investment conditions could improve both profitability and investment security. A dedicated market for energy or electricity reserves, where resilience is treated as a tradable good, could provide additional incentives for investment.

Beyond economic aspects, regulatory and social issues must also be addressed. For example, spatial planning requirements for thermal storage, particularly underground, remain poorly defined. Coordinated legal frameworks with neighbouring countries will also be necessary for establishing a future hydrogen infrastructure.

Finally, the realization of such storage projects will depend heavily on public acceptance. While hydropower is broadly accepted, there is little knowledge about how the public perceives new storage technologies like rock caverns or large-scale thermal storage systems.

Consequently, several critical questions remain unanswered regarding the integration of seasonal storage into Switzerland's energy system. These are identified and systematically listed in the second part of this report.

Contents

List of abbreviations

AT	Ambient temperature
ATES	Aquifer thermal energy storage
BTES	Borehole thermal energy storage
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CTES	Cavern thermal energy storage
CHP	Combined heat and power
DH	District heating
DUT	Directly usable temperature
EHB	European Hydrogen Backbone
EU	European Union
ETS	Emissions Trading System
FT	Fischer-Tropsch
LCOS	Levelized cost of storage
LHV	Lower heating value
LRC	Lined rock cavern
NG	Natural gas
OPEX	Operational expenditure
P2X2P	Power-to-X-to-power
PCM	Phase change material
PHES	Pumped hydroelectric storage
PTES	Pit thermal energy storage
PV	Photovoltaic
SAF	Sustainable aviation fuel
STES	Seasonal thermal energy storage
TES	Thermal energy storage
TRL	Technology Readiness Level
TWh	Terawatt hour
TTES	Tank thermal energy storage
VSG	Verband der Schweizerischen Gasindustrie

1 Introduction

Ensuring a secure and resilient energy supply during winter is one of the major challenges of a future renewable-based Swiss energy system. Various strategies have been proposed to address this issue, including shifting surplus summer energy to winter, increasing the proportion of dispatchable energy sources (e.g. gas turbines), expanding the capacity of seasonally suitable non-dispatchable renewables (e.g. wind), and still increasing the capacity of seasonally mismatched renewables (e.g. rooftop PV), albeit with higher summer curtailment. Other options include energy imports during winter and reducing winter energy demand.

Among these, seasonal energy storage technologies offer a particularly promising avenue. The expected overproduction of electricity and heat in summer underscores the opportunity to identify cost-effective methods to shift surplus energy into winter. Furthermore, seasonal storage could support the integration of high shares of renewable energy, improve overall system efficiency, reduce dependency on energy imports, and enhance resilience.

Despite the conceptual appeal of seasonal storage, its practical role remains difficult to assess. The energy system's complexity — characterized by interdependent infrastructures, geographical and geological constraints, and sociopolitical factors — poses significant challenges. The feasibility of seasonal storage technologies hinges heavily on other system components. In addition, uncertainties in infrastructure development, energy import costs, market and regulatory developments, and public acceptance further complicate matters.

Although energy system optimisation models frequently evaluate combinations of the above-mentioned strategies, including storage, real-world implementation diverges from model assumptions. These models must be simplified to remain computationally manageable, which limits the robustness of the model results. Many do not include certain storage technologies such as seasonal thermal energy storage (STES) at all, neglecting potentially transformative technologies. Furthermore, assumptions about future import prices, regulatory developments, and social behaviour introduce additional layers of uncertainty.

Implementing model-derived strategies in the real world involves economic, regulatory and societal challenges. Investment security and economic viability, regulatory clarity, and societal acceptance are crucial for practical implementation, often determining the success or failure of technically sound solutions. Therefore, system transformation demands not just modelling, but also a detailed understanding of real-world constraints and enablers.

The high complexity and relative novelty of many seasonal storage technologies have resulted in numerous knowledge gaps. Closing these gaps is essential in order to clarify the potential role of seasonal storage, enable cost-effective deployment and ensure that seasonal storage maximises its benefits for the overall system. Filling these gaps will support the transformation of the energy system in line with the Energy Strategy 2050.

Chapter 2 of this report provides an overview of the current state of knowledge from a holistic perspective. It discusses seasonal storage options and the associated energy infrastructure briefly, and examines the corresponding market aspects, regulatory framework, and social acceptance. This review is based on a literature review and expert interviews. The Swiss Academies of Arts and Sciences will publish a report for a broader audience based on the information in this chapter.

Gaps in knowledge were identified by reviewing the current literature for missing relevant information, by interviewing experts, and by discussion in a workshop. Chapter 3 describes and ranks the resulting research needs according to their importance and urgency.

2 Current state of knowledge

2.1 Seasonal storage

Seasonal energy storage refers to long-term storage with which energy can be stored for multiple months in a cost-effective manner and which is typically cycled mainly on a seasonal basis. Some storage is charged by natural energy inflows (inflow storage), such as in the case of large hydroelectric dams, while others are charged actively (chargeable storage), such as in the case of seasonal thermal energy storage (STES). Naturally, only chargeable storage can be charged by surplus electricity in summer. The distinction between short-term storage (seconds to several days) and long-term storage (months) is sometimes determined by technical factors, such as self-discharge. However, it is more commonly influenced by economic considerations. Consequently, batteries, adiabatic compressed air energy storage (A-CAES) and pumped hydroelectric storage (PHES) are not considered suitable for long-term storage.

Today, Switzerland has large hydroelectric dams that provide some seasonal storage capacity for dispatchable electricity generation (with a theoretical capacity of 8.9 TWh_{el}; see Chapter 2.1.1). Additionally, some biomass is used seasonally (for space heating), but fossil fuels provide most of the seasonal flexibility, with a substantial backup reserve of around 40 TWh_{LHV} (BWL, 2023). Gas is imported continuously without significant domestic storage. However, utilities are currently required to secure at least 15 % of their annual gas demand in storage facilities abroad, which corresponds to around 6 TWh_{LHV}.[1]

Table 1: Overview over long-term energy storage options with related energy carriers, maturity and estimated usable capacity in 2050. There are thermal storage technologies that are able to store heat at directly usable temperatures (DUT) and others storing heat at ambient temperature (AT), requiring a heat pump for discharging. The colour indicates different types of stored energy forms: yellow: potential energy/electricity, orange: thermal energy, blue: chemical energy.

Technology	Energy form	Maturity	LCOS estimation[A] (CHF/MWh)	Estimated usable capacity by 2050
Large dam hydroelectric power	Potential energy (Electricity)	Mature (TRL ≥9)	Inflow storage[B]	<10.9 TWh_{el}[C] (<8.9 TWh_{el} today) (Boes et al., 2021)
Lakes	Sensible heat (AT)	Mature (TRL ≥9)	Inflow storage[B]	≤ 6 TWh_{th} (chargeable), potential much larger (very little today) (Guidati & Marcucci, 2023)
Borehole Thermal Energy Storage (BTES)	Sensible heat (DUT or AT)	Mature (TRL ≥9)	AT: 40, DUT: 110 (Haller & Ruesch, 2019)	
Aquifer Thermal Energy Storage (ATES),	Sensible heat (directly usable temp. (DUT) or ambient temp. (AT))	Emerging in CH, established in other countries (TRL ≥9)	AT: 25 DUT: 32 (Haller & Ruesch, 2019)	
Pit Thermal Energy Storage (PTES)	Sensible heat (DUT)	Not established in CH, but in other countries (TRL ≥9)	DUT: 18 (Haller & Ruesch, 2019)	
Cavern Thermal Energy Storage (CTES)	Sensible heat (DUT or AT)	In development (TRL <5, see SwissSTES flagship project)	No CH-specific data available	
Tank Thermal Energy Storage (TTES)	Sensible heat (DUT)	Mature (TRL ≥9)	DUT: 170 (Haller & Ruesch, 2019)	

[1] Art. 2 para. 2 Verordnung über die Sicherstellung der Lieferkapazitäten bei einer schweren Mangellage in der Erdgasversorgung

Phase Change Materials (PCM) Storage (Ice Storage)	Latent heat (DUT or AT)	Ice storage commercially available (TRL ≥9), new types under development	Ice AT: 120 (Haller & Ruesch, 2019)	
Sorption storage	Chemical heat (DUT)	In development (TRL 6-9) (Schmidt et al., 2020)	No CH-specific data available	
Lined rock cavern (LRC)	Chemical energy (methane, hydrogen)	First commercial sites (methane), (Glamheden & Curtis, 2006), in development (hydrogen, TRL 5) (Hydrogen TCP-Task 42, 2023), no sites yet in Switzerland	15 for methane (Kober et al., 2024), no CH-specific data available for hydrogen	0–2.3 TWh_{LHV} (none today) (BFE, 2021; Marti et al., 2022; Panos et al., 2021)
Cryogenic Storage	Chemical energy (methane)	Mature (TRL ≥9)	No CH-specific data available	0 (none large scale sites today)
Porous rocks/depleted gas fields	Chemical energy (methane, hydrogen)	Mature (TRL ≥9 for methane, TRL 3-4 for pure hydrogen (Hydrogen TCP-Task 42, 2023)	No CH-specific data available	Unclear potential in CH
Salt cavern	Chemical energy (methane, hydrogen)	Mature (TRL ≥9)	No CH-specific data available	Unclear potential in CH
Liquid fuel storage	Chemical energy (liquid fuels like Diesel, Kerosene)	Mature (TRL ≥9)	Very low[D]	≤40 TWh_{LHV} (today ~40 TWh_{LHV}) (BWL, 2023)
Dry biomass (wood fractions)	Chemical energy (dry biomass)	Mature (TRL ≥9)	Very low[D]	Up to 15–19.6 TWh_{LHV}[E] (today: ≤13.2–15.8 TWh_{LHV}[E]) (Guidati et al., 2021)
Metal fuel storage	Chemical energy (metals)	In development (TRL 4–7) (Bäuerle et al., 2024)	Likely low[D]	0–several TWh (Bäuerle et al., 2024) (none today)

[A] The levelized cost of storage (LCOS) is highly dependent on the number of charge-discharge cycles that can be achieved, as well as on the cost of charging. The latter is largely determined by the frequency and magnitude of energy price fluctuations. Due to the considerable uncertainty surrounding future price fluctuations in the energy system, all LCOS estimates are highly uncertain.

[B] Inflow storage is typically not described by LCOS

[C] As the reservoirs are almost never fully emptied (historically by an average of 73 %, Boes et al., 2021), the 'usable' capacity is less than the theoretical capacity.

[D] The storage of liquid and solid energy carriers is simple and therefore likely to be relatively inexpensive, but no CH-specific LCOS data is available.

[E] The indicated amount is the estimated sustainable potential of woody biomass in Switzerland. Due to competing uses (e.g. timber for construction vs. process heat), only a smaller amount will be available for seasonal energy storage.

2.1.1. Storage in the electricity sector

Large dam hydroelectric storage

Historically, operators have only utilised an average of 73% of the theoretical annual storage capacity of 8.9 TWh_{el}, due to factors such as increased sediment flow at low fill levels and reserve requirements reducing practical usability and discouraging full reservoir depletion. Potential future capacity increases are estimated to be between 0.3 and 2.7 TWh_{el}, primarily through raising the height of dams (0.2–1.5 TWh_{el}), a few new construction projects (0–1 TWh_{el}) and refurbishment of existing plants (0.1–0.2 TWh_{el}) (Boes et al., 2021). A roundtable of experts estimated a realistic capacity increase of 2 TWh_{el}

by 2040, spread over 15 specific projects (Runder Tisch Wasserkraft, 2021). These projects are explicitly mentioned in the Electricity Supply Act and are considered priority projects.[2]

To prevent the reservoirs from being completely emptied before the inflow resumes at the end of spring, a mandatory water reserve has been established. ElCom sets the required capacity for this reserve, which larger plant operators must withhold. Residual flow regulations, which were introduced to limit negative impacts on biodiversity, enforce minimal residual water flows downstream of the dam that could significantly affect total annual energy production in the future (Pfammatter & Semadeni Wicki, 2018). However, the precise impact on seasonal storage capacity and winter electricity generation remains unclear. Sustained low electricity prices in summer and high water charges could also significantly impact the economics if water has to be released due to residual flow regulations and/or if storage capacity is lower than summer inflows. Future economic performance also depends on developments in European electricity markets and on agreements between the EU and Switzerland, as these can significantly affect operational strategies and economic viability (Barry et al., 2019).

Climate warming is expected to lead to more extreme weather conditions, including longer periods of drought and more frequent heavy rainfall, which can cause flooding (Müller-Ferch et al., 2019). Such flooding poses significant challenges for plant operators, requiring the development of effective flood retention strategies and the management of increased sediment influx, which leads to accelerated reservoir siltation. The timing of snowmelt and glacier water supply, as well as seasonal precipitation patterns, are also predicted to change. The annual peak inflow is expected to occur earlier in spring and be less pronounced, becoming more evenly distributed throughout the year. There will be increased precipitation in winter and reduced precipitation in late summer and autumn (BAFU, 2021). The ramifications of these effects may be that reservoirs also need to be used for purposes other than energy storage, such as flood retention and supplying drinking water and water for alpine agriculture. This could potentially limit the capacity available for winter electricity production and challenge the targeted increase of 2 TWh_{el} of winter electricity production.

Electricity production from waste and biomass

The expected annual amount of sustainably grown biomass available for energy purposes is estimated to be around 26.9–32.2 TWh_{LHV} per year by 2050 (Guidati et al., 2021). Of this, 13.2–15.8 TWh_{LHV} are seasonally storable dry biomass fractions, while the remainder are wet biomass fractions that require continuous processing, with the resulting fuels/gases potentially being stored seasonally. Currently, only a small amount of electricity is produced from biomass; it is mostly used for generating heat.

Municipal and other waste fractions will account for 17–20.6 TWh_{LHV} of the potential in 2050 (Guidati et al., 2021). Today, annual electricity production from incineration plants is around 2 TWh_{el}. As the potential is set to increase only slightly, according to (Guidati et al., 2021), winter electricity production is expected to remain at approximately 1 TWh_{el}, assuming continuous incineration of waste.

According to a back-of-the-envelope calculations (see Appendix 5.2), only around 1.8 TWh_{el} of electricity can be produced using sustainable biomass in the winter months (in an optimistic case). There are several ways to increase biomass's impact on the electricity sector, such as increasing electricity production and/or reducing demand by replacing heat pumps, as discussed in Chapter 2.3.3. However, the prioritisation of biomass for electricity generation competes with other arguably more important uses, such as generating high-temperature heat for industrial processes and negative emissions, so synergies must be identified and trade-offs discussed.

Power-to-X-to-power

Storing electricity in power-to-X-to-power (P2X2P) processes is the most prominent option for effectively shifting surplus electricity over long periods. The main challenges are the relatively low round-trip efficiencies of <45 % at best for hydrogen and <30 % for liquid energy carriers (Sterner et al., 2011), which result in economic challenges (see Chapter 2.3.2). The next chapters will discuss feasible production paths for storable energy carriers in more detail, as well as their transport and storage.

[2] Annex 2 Federal Electricity Supply Act

2.1.2. Storage in the heat sector

Based on the results of an energy system model, it is estimated that integrating seasonal thermal storage could reduce the winter electricity demand by 2–4 TWh_{el} (Guidati et al., 2022; Guidati & Marcucci, 2023). The estimated potential capacity of thermal storage is much higher, as stated in the respective technology descriptions below (Jakob et al., 2020). Chapter 2.2.2 discusses the different options for heat supply and the impacts on other sectors in more detail.

The following points provide a brief description of common seasonal thermal energy storage technologies. More detailed information can be found in dedicated reviews (e.g. Haller & Ruesch, 2019; Mahon et al., 2022; Yang et al., 2021).

- Although the theoretical thermal capacity of Swiss **lakes** is very large at 134 TWh_{th}, a detailed anaysis shows that the practical potential is around 8 TWh_{th} or less (BFE, 2021; Gaudard et al., 2019). Lakes are particularly attractive in combination with a 5th generation district heating and cooling network (5GDHC), acting as a temperature buffer for both heating and cooling.
- **Borehole thermal energy storage** (BTES) uses the heat stored in the ground, accessed by an array of ground heat exchangers at depths of 50–500 metres. In addition to heat pumps, attractive heat sources include solar thermal collectors or waste heat (Kirschstein et al., 2024). Regenerating the ground temperature in hot periods rather than simply extracting heat in the heating period allows 4–6 times more heat to be extracted per volume of rock (BFE, 2021) and enabling buildings to be cooled during hot periods. The potential in Switzerland is estimated to be 31–35 TWh_{th} (Jakob et al., 2020). If the average annual storage temperature is equal to the depth-specific ground temperature, there is no net heat loss, resulting in an equalised energy balance (equivalent to a storage efficiency close to 100 %). Retrofitting BTES is challenging due to space requirements during construction, and interference with groundwater can be limiting (see Chapter 2.6.2). Additionally, heat transfer rates are relatively low compared to other STES options; therefore, short peaks during charging/discharging must be buffered with short-term thermal storage. It is possible to heat BTES to temperatures that can be used directly. However, higher losses result from the inability to insulate the storage except at the surface. This makes the economic viability of BTES dependent on the specific characteristics of each individual project. In most cases, using a very low-cost heat source is essential to ensure that BTES is economically competitive at directly usable temperatures compared to alternative solutions (Haller & Ruesch, 2019; Ruesch et al., 2018).
- **Aquifer thermal energy storage** (ATES) stores heat in underground aquifers (with no or minimal flow speeds). The efficiency depends on depth and storage temperature. Due to the geothermal gradient, greater depths can store higher temperatures more efficiently. Depths of 20–200 m are common for smaller installations operating at or slightly above ambient temperatures. These installations represent the most widely used STES systems in the world today. Switzerland's estimated physical potential is 9–13.7 TWh_{th} (Jakob et al., 2020). Larger installations at higher temperatures can reach much deeper (up to 2000 m) (Fleuchaus, 2020; Haller & Ruesch, 2019) with a large physical potential of 13–146 TWh_{th} (Jakob et al., 2020). ATES requires suitable geological conditions, such as natural cavities or porous rocks with good transmissivity. ATES must comply with groundwater protection measures and adhere to permitted temperature changes in groundwater (see Chapter 2.6.2). Storage in deeper reservoirs may interfere with shallow aquifers that are subject to special protection requirements during construction. Furthermore, the current lack of documentation on deep aquifer systems in Switzerland is a limiting factor, likely resulting in high costs for deep underground exploration.
- **Pit thermal energy storage** (PTES) involves large, sealed pits that are filled with hot water (up to 90 °C) and are typically only insulated at the top. Efficiencies of up to 90 % have been achieved in practice due to the large volume and with precise layering of the water (thermal stratification) (Xiang et al., 2022). PTES storage is a mature technology that has already been proven in other countries, such as in Denmark (Haller & Ruesch, 2019). It is typically charged with waste heat from incinerators, solar thermal collectors, or heat pumps. However, PTES requires a relatively large surface area in or near settlements due to the difficulty of transporting heat, which makes construction in

densely populated areas challenging. In addition, current regulations make it very difficult to build PTES on anything other than (expensive) building land (see Chapter 2.6.2).

- **Cavern thermal energy storage (CTES)** involves storing heat in man-made cavities, such as basements, tunnels, or other abandoned structures. In addition to ambient temperatures, direct use temperatures can be stored, provided an insulating lining is used. While this type of storage is particularly attractive in dense urban areas where alternative types of storage are not feasible, there is currently little practical experience of implementing CTES; however, research is ongoing (Worlitschek, 2024).
- **Tank thermal energy storage (TTES**) uses a large, water-filled container charged in summer, typically via solar thermal collectors. As the stored heat can be used directly, no heat pump is required during discharge, reducing winter electricity demand. To recover heat losses, the tank should be integrated into buildings, occupying valuable living space. Due to high costs (tank, insulation, collectors) and space requirements, TTES is highly location-dependent and unlikely to be feasible in dense urban areas with high real estate prices (Haller & Ruesch, 2019; Ruesch et al., 2023).
- **Ice storage** uses a water tank frozen by a heat pump extracting heat, resulting in relatively high energy density. Charging typically occurs via thermal solar collectors or heat pumps (for space cooling). When maintained at 0 °C, storage efficiency can exceed 100 % for heating, as ambient temperatures are generally higher. Ice storage is particularly suited for compact settings requiring high energy density where installing heat pump air exchangers is difficult (Schmidt et al., 2020). Similar systems use other phase change materials (PCMs) with higher melting points than water, allowing for greater heat pump efficiency. However, these PCMs are more expensive than pure water, and most of them are still in the research stage (Haller & Ruesch, 2019).
- **Thermochemical (sorption) storage** provides a means of long-term thermal load shifting through the storage of chemical potential. This approach allows for higher volumetric energy storage densities compared to traditional water storage systems, as well as high long-term storage efficiencies, even at a building scale. However, it requires complex and expensive equipment, and its performance is strongly dependent on the application temperature. It is also still in the research stage (Haller & Ruesch, 2019; Schmidt et al., 2020).

2.1.3. Storage of chemical energy carriers

Since the storage of solid and liquid energy carriers is trivial and well-established, this section will focus on the storage of gaseous energy carriers. Currently, Switzerland has no large-scale gas storage facilities, but utilities are required to have agreements with European storage providers to secure at least 15 % of the yearly demand.[3] There are also solidarity agreements between Switzerland and France, Germany and Italy, to ensure a secure gas supply (BFE, 2009a; UREK-N, 2025). For storing gaseous energy carriers on a larger scale, Switzerland has the following options:

- **Lined rock caverns** (LRCs) are artificially created caverns that are coated with a concrete and stainless steel or polymer lining (Masoudi et al., 2024). This option requires a larger capital investment than porous rock storage per capacity (see third bullet point). However, they can be deployed in various geological settings and can also be adapted for hydrogen storage. A natural gas (NG) storage project in Switzerland is currently underway in Oberwallis, with a planned capacity of around 1.2 TWh_{CH4} (Gaznat SA, 2021). Although LRCs can store hydrogen, its lower energy density means that less energy can be stored per unit of volume than with methane (by a factor of 3.2; Bossel & Eliasson, 2003). Hence, the capacity of the planned LRC in Oberwallis would be reduced to around 0.4 TWh_{H2}. Although there is a commercial LRC for methane storage in operation (Skallen in Sweden) (Johansson, 2014) and one hydrogen LRC project underway (Luleå, Sweden) (Johansson et al., 2018), knowledge, in particular for large capacities, is very limited.
- **Cryogenic storage** of gases in large insulated tanks is possible, but reduces efficiency, as about 10 % of the energy content is required for liquefaction in the case of methane (BFE, 2022). Losses

[3] Art. 2 para. 2 Verordnung über die Sicherstellung der Lieferkapazitäten bei einer schweren Mangellage in der Erdgasversorgung

for hydrogen liquefaction are even greater, as much lower temperatures need to be reached (-253 °C for hydrogen vs. -162 °C for methane). The discharge rate of such storage is slow because the liquid must first be gasified, which limits the potential for dynamic stabilisation of gas networks. Due to the high cost (CAPEX and OPEX) of such storage solutions, their large scale deployment is viewed critically (Kober et al., 2024).

- In Europe, most NG storage facilities use **porous rock and depleted gas fields** (Kober et al., 2024). However, it is currently unclear whether such geological formations exist in Switzerland. Rough estimates of the potential for CO_2 storage in similar geological formations in Switzerland suggest that suitable geological formations (porous rock with impermeable caprock) are available in principle. Nevertheless, considerable uncertainty remains regarding the actual potential (Driesner et al., 2021; Konegger et al., 2023). Additionally, porous rock may be less suitable for hydrogen storage as bacteria can convert some of the hydrogen to methane (BFE, 2022; Konegger et al., 2023).
- **Salt caverns** are popular in Europe for storing gaseous chemical energy carriers (Gas Infrastructure Europe, 2021). In suitable locations, salt caverns usually require lower CAPEX than lined rock caverns, as they are simpler to construct (no lining is required), while offering similar technical characteristics in terms of operation (i.e., charge/discharge rate, purity of stored gas and pressure) (Londe, 2021). In Switzerland, the availability of suitable, thick layers of salt is not well known publicly, although salt deposits do exist in Switzerland, but they are usually not very thick (Hälfiger, 2024). While existing exhausted salt caverns from rock salt extraction are unsuitable for conversion to gas storage, future caverns could theoretically be built to be later used as gas storage (Regierungsrat BL, 2024).
- Contracts with **foreign storage** providers offering guaranteed access are likely the most cost-effective option (storage-only costs are less than half of domestic LRCs), given the large available capacities. However, they do not allow for services like dynamic gas network stabilisation, and Switzerland remains exposed to import price volatility. Access frequency, response time, and emergency provisions depend heavily on contract terms (Kober et al., 2024).

Of the technologies available for storing gas domestically, LRCs appear to be the most cost-effective option for medium- to large-scale facilities in Switzerland. Estimates show that around 1.3 TWh_{CH4} of domestic gas storage capacity is of systemic importance when used alongside gas storage abroad, as it can save costs and significantly increase resilience in the event of a sudden disruption in the supply chain (Kober et al., 2024). As hydrogen might become important by 2040-2050, methane storage facilities should be built hydrogen ready.

With large gas-fired backup plants being installed in Switzerland, large LRCs can stabilise the gas grid when these plants are switched on and the storage is located nearby (Kober et al., 2024). If, as is currently the case, Switzerland only secures some gas abroad, or stores gas in liquid form, the dynamic stabilisation of the gas grid will not be possible and additional short-term storage will be needed.

2.2 Storage integration in seasonal supply-demand pathways

2.2.1. Seasonal flexibility in the electricity sector

To understand the role, benefits and limitations of seasonal storage within the energy system, it is important to compare it with other strategies for reducing the mismatch between supply and demand. In the electricity sector, flexibility across all timescales is increasingly important. While many technologies can provide short-term flexibility (up to several days), seasonal storage remains one of the few options for long-term flexibility. Notably, despite its primary value in seasonal applications, it can also contribute to short-term flexibility needs.

Chapter 1 discussed several strategies to close the supply-demand mismatch. The extent to which these strategies are implemented will, in turn, affect how much seasonal energy storage is still needed to close the supply-demand gap. However, each alternative has its limitations. The expansion of wind and PV currently faces significant challenges, primarily in terms of acceptance (wind) and economics (alpine solar). Large gas turbines and electricity imports rely on imported energy, which raises concerns about resilience (see discussion in Chapter 2.5). While extending the life of existing nuclear plants may be appealing (VSE, 2025b), the economics of constructing new ones is questionable in a system dominated by renewable energy sources (Neu et al., 2025). High shares of renewables tend to encourage the development of flexible generators with low CAPEX and high OPEX to cover the residual load and/or serve as backup generators. Furthermore, it is highly unlikely that any new nuclear power plant can be commissioned before 2050 (Neu et al., 2025), meaning that the transition in line with the Energy Strategy 2050 will have to rely on alternative technologies.

In addition to the strategies to reduce the supply-demand mismatch that were discussed in Chapter 1, seasonal storage can also contribute significantly to relieving the mismatch. Large hydropower already operates seasonally, with output concentrated in high-price winter periods. Seasonal thermal energy storage with power-to-heat units can further shift electricity demand on both short- and seasonal time-scales, leading with savings of up to 4 TWh_{el} in winter (Guidati et al., 2022; Guidati & Marcucci, 2023). Similarly, power-to-X-to-power technologies can absorb surplus electricity and reconvert it when needed, but require seasonal gas storage and likely complementary short-term storage to ensure high load factors. As discussed in chapter 2.3.2, the latter option is pricey and for large scales likely the most expensive option.

In many cases, alternatives to seasonal storage, such as wind power, are economically more attractive. Therefore, the required type and capacity of seasonal storage is highly dependent on the extent to which these alternatives are implemented/available.

2.2.2. Flexibility in the heat sector

As the heating sector is one of the largest contributors to the seasonal supply-demand mismatch in the energy system, heat provision — particularly space heating in combination with thermal storage — constitutes a significant means of addressing the mismatch.

While **heat pumps** are required to discharge ambient temperature STES (e.g. BTES, ATES), they could also be used to charge both ambient and direct use temperature STES (e.g. PTES) in summer. Using ambient temperature STES can increase the efficiency of heat pumps compared to air-water heat pumps, saving electricity in winter (Ougazzou et al., 2024). Using direct use temperature STES can also eliminate most of the electricity demand during discharge. Additionally, recharging STES in summer could be advantageous during periods of low electricity prices and/or by utilizing otherwise curtailed rooftop PV from the same or nearby buildings. The intelligent control of heat pumps in both summer and winter is a key element of demand-side management (DSM), as it enables dynamic load adjustment to support grid stability and relieve stress on the electricity network (Kauko et al., 2024). Furthermore, as climate change is expected to significantly impact heating and cooling demand, with an anticipated surge in cooling degree days (CDDs) of approximately 600% under the RCP4.5 (CH2018) scenario (Berger & Worlitschek, 2019), the integration of heat pumps with STES becomes particularly pertinent. This allows heat generated by summer cooling to be used for heating in winter, while making use of abundant electricity supply in summer and reducing electricity demand in winter.

In addition to heat pumps, there are many **other potential heat sources** available. Solar thermal collectors can produce temperatures of up to 200 °C (Delcea & Bitir-Istrate, 2021) and can be used to charge all types of STES. Rooftop panels can be sufficient for small STES (e.g. TTES and ice storage), whereas large collector fields are required for larger STES (e.g. PTES). Non-dispatchable (base-load) heat and combined heat and power (CHP) plants (waste incinerators, sewage treatment plants) produce excess heat in summer. This excess heat could be stored at directly usable temperatures (e.g. PTES, ATES) to reduce the combustion of energy carriers in winter for peak shaving. There are options to seasonally flexibilise waste incinerators, discussed in Chapter 2.3.3. Dispatchable CHP plants, which only run in winter to specifically provide electricity and heat, are usually fired by gas or wood. Including an STES charged by power-to-heat or solar thermal collectors in summer could reduce the amount of required valuable gas or wood and allow greater flexibility in prioritising electricity and heat production (see the next section for more information on seasonal scheduling). Furthermore, waste heat from industrial facilities, energy conversion plants and, increasingly, data centres could be used to charge

STES during the summer months. While deep geothermal heat is not typically considered a storage technology, it remains a promising solution for supplying heat networks and is constantly being improved to address challenges such as the risk of inducing earthquakes (Sierro et al., 2024; Wyss, 2013).

2.2.3. Seasonal scheduling

Taking into account the seasonal characteristics of supply and demand, sector coupling, and storage technologies, the supply-demand pathway can be adjusted to enable greater efficiency through seasonal scheduling. The integration of a STES charged by heat pumps or baseload heat or CHP plants during the summer months has the potential to further reduce the reliance on valuable chemical energy carriers for winter peak shaving (Vilén & Ahlgren, 2024), as discussed in Chapter 2.2.2. Baseload incineration plants can store summer waste in compressed bales, reducing summer heat loss and increasing winter heat production (Fuhrer et al., 2025). The idea of seasonal scheduling can also be applied to other processes, such as upgrading biomass: During the summer months, surplus electricity could be used to produce hydrogen, which can be used to upgrade the residual CO_2 from biomass conversion, thereby increasing the yield of methane (Gantenbein, 2022). The methane produced can be stored seasonally, for instance in LRCs to meet higher winter demand. In winter, the biomass plant continues the production of methane, while employing the remaining unconverted CO_2 for negative emissions via final permanent storage. A back-of-the-envelope calculation is presented in Appendix 5.2 to estimate the potential for upgrading biomass with hydrogen. It is also possible to increase the yield of biomethane/biofuel from endothermic biomass conversion using waste heat from summer (e.g. from an incineration plant) (Moret et al., 2016).

While the combined quantitative potential of the discussed seasonal scheduling options in alleviating the seasonal supply and demand challenge is unclear, systematically implementing such optimised seasonal processes could be an important approach to addressing the seasonal challenge.

2.3 Production of chemical energy carriers in Switzerland

2.3.1. Production pathways

The challenge of seasonal energy storage in the form of chemical energy carriers lies less in the storage itself than rather in their initial production. Therefore, potential production pathways that may be feasible within the Swiss context are briefly presented and discussed.

Hydrogen

Hydrogen serves as a feedstock for the synthesis of hydrocarbons and chemicals in general but is also an energy carrier in its own right. There are multiple ways to produce hydrogen domestically in a carbon neutral way:

- Via water electrolysis using renewable electricity (mature).
- Biomethane can be further converted to hydrogen by steam or autothermal reforming (SMR or ATR, mature) or by pyrolysis (producing solid carbon, TRL 6; IEA, 2023) .
- Biomass gasification produces syngas, which can be further converted to hydrogen and carbon dioxide by means of the water-gas shift reaction (mature).

If the production site is not connected to a hydrogen pipeline, as is likely to be the case for more remote sites, the hydrogen will probably need to be used directly on site, either as an energy carrier or as feedstock to upgrade the product gas from a gasification process, for example, into methane that can then be injected into the gas grid. As discussed in Chapter 2.4.2, blending some hydrogen directly into methane networks might also be possible. When hydrogen is produced from biomass, the resulting carbon by-product can be used to generate negative carbon emissions. This strengthens the business case for hydrogen production in the event of high carbon prices. While hydrogen production from biomass is feasible year-round as biomass is constantly available and no significant electricity input is required, production from electricity is mainly viable during the summer, when electricity prices are low.

Methane

Methane production can be achieved through various processes, including biomass conversion, electrical synthesis, or a combination of both. The most attractive options for Switzerland are as follows:

- In anaerobic digestion, microorganisms convert biomass in the absence of oxygen in a series of processes to methane (50–75 %) and carbon dioxide (30–40 %) and a few other residual gases (Neri et al., 2023). This process is already established in Switzerland and is relatively inexpensive but has a low efficiency of 30 % (lower heating value (LHV) out/in) (Guidati et al., 2021).
- Hydrothermal gasification is a novel process (TRL 6–9; Muhlke et al., 2023), in which biomass is decomposed in a supercritical phase above 370 °C and 220 bar. This process converts wet biomass with very high efficiency (above 60 %) and produces biogas with a high methane fraction of up to 70 % (Guidati et al., 2021). Hydrogen injection could increase the methane fraction (Muhlke et al., 2023). The technology requires relatively complex equipment (compared to anaerobic digestion), which favours larger plants.
- Gasification is a thermochemical conversion process, in which preferably dry (woody) biomass is decomposed at temperatures above 700 °C to produce syngas. An additional methanation step can then convert this into methane and CO_2 (TRL 7–8; Schildhauer et al., 2021). The methane yield can be increased by injecting additional hydrogen, while simultaneously reducing the emerging carbon dioxide fraction.
- Electrically synthesised hydrogen can be combined with captured CO_2 to form methane in the Sabatier reaction (mature). Other novel options for the direct synthesis of methane include reversible methane fuel cells (e.g. high-temperature solid oxide fuel cell, SOFC), which use steam and pure CO_2 as inputs to produce methane (TRL 5–6; Wang et al., 2018). Another option is geo-methanation, in which microbes in porous rocks below 600 metres combine hydrogen and carbon dioxide to produce (and store) methane (TRL 8; Konegger et al., 2023; Teske et al., 2019).

As the feedstock for wet biomass conversion plants cannot be stored and accumulates continuously, the corresponding processes must also run continuously. Only the resulting methane can potentially be stored seasonally. In contrast, processes using dry biomass could theoretically be scheduled seasonally (e.g. only operating in winter), as the feedstock is easily storable. However, this results in a significant increase in costs due to the lower capacity factor of the plant.

Methanol, diesel, kerosene

Biomass or electricity can be used to produce liquid energy carriers such as methanol or hydrocarbons (e.g. diesel or kerosene). The process can vary depending on the source material and the desired end products.

- Power-to-liquid via electrolysis of hydrogen and green (bio- or air-based) carbon can produce methanol through the methanol synthesis process (TRL 7–8) or hydrocarbons through Fischer-Tropsch (FT) synthesis (TRL 5–7) (Batteiger et al., 2022).
- Syngas, produced through wood gasification or methane reforming, can be liquefied in the FT synthesis to produce bio-crude oil (mature).
- Biogas, produced through digestion or hydrothermal gasification, and syngas, produced through wood gasification, can be converted into methanol (TRL 8–9; Kang et al., 2021).
- Pyrolysis of dry biomass or hydrothermal liquefaction of wet biomass produces a wide range of solid, liquid and gaseous products (e.g. bio-crude oil) simultaneously (TRL 7–9 for pyrolysis oil, 6–7 for refined fuels) (Wijeyekoon et al., 2020).
- There are other ways to produce liquid fuels, such as reforming waste vegetable oil to create hydrotreated vegetable oil (HVO) fuels. However, as the availability of the feedstock is very limited in Switzerland, these processes will only be able to provide a small proportion of the required liquid fuels.

Most options involve complex, high CAPEX processes (e.g. bio-crude refining) and therefore benefit greatly from economies of scale. Large-scale plants are unlikely to be viable in Switzerland due to the lack of constant, cheap electricity (power-to-liquid) and biomass (biomass conversion) supplies, meaning they are unlikely to be price competitive with imports of synthetic fuels. However, there are no reliable cost estimates yet for larger-scale domestic production of liquid fuels. When combined with the production of higher-value chemicals for industry, a bio-crude refinery could become more attractive. Smaller methanol production plants that do not require a bio-crude refinery could be feasible under certain conditions, such as a low electricity price and low CO_2 cost (Moioli et al., 2022). Since the liquid products are easy to store, biomass conversion plants can run continuously to maximise the capacity factor. However, power-to-liquid plants will likely have to shut down during periods of high electricity prices in winter, despite the reduction in capacity factor.

Ammonia, metal fuels

- While ammonia is not an attractive power-to-X-to-power energy carrier due to its low conversion efficiency and toxicity, it could be used to transport hydrogen over very long distances (>2000 km), in which case it could be more economical than using pure hydrogen (Patonia & Poudineh, 2020).
- Electrically reduced metals can be oxidised to produce heat and hydrogen and can therefore be used for energy storage. While the properties of metallic fuels are promising for seasonal energy storage, the potential future applications and suitability for energy storage remain uncertain due to limited knowledge of these processes (TRL 4–7) (Bäuerle et al., 2024).

2.3.2. Economics of power-to-hydrogen

Since hydrogen is a key component of most synthetic fuels, the economic efficiency of its production fundamentally determines the economics of all hydrogen-based fuels (e.g. e-methane and e-fuels). The economic performance of future domestic hydrogen production using electricity is difficult to predict, as it depends on electricity prices and the CAPEX of the production chain. However, from a load factor of around 0.45 (4,000 full load hours) or higher, the effect of CAPEX becomes insignificant, with production costs being primarily determined by the electricity price (Brockhaus, 2022; Marti et al., 2022). Operating electrolysers solely during sunny periods in summer would lead to extremely low electricity prices, yet this would not suffice to achieve the required load factor. This is because only around 1,100 full-load hours of rooftop PV are feasible in Switzerland (Boulouchos et al., 2022). Adding short-term storage, such as batteries, to balance day-night variations could increase the load factor but would also increase CAPEX (or OPEX if costs are integrated into the price of purchased electricity). While locating electrolysers adjacent to electricity generators, such as run-of-river plants, would exempt them from grid fees,[4] this would not reduce electricity tariffs. Furthermore, it would likely require investment in hydrogen transport infrastructure to demand centres, which can be costly. Exemptions from grid fees for sites that are not adjacent to run-of-river plants or other electricity sources and therefore draw electricity from the grid could lead to market distortions and, if considered, will need to be well regulated to remain fair and system friendly (Worm et al., 2023). Currently, grid fees for electricity generated by P2X2P plants and, with certain limitations, for electricity consumed by demonstrator/pilot plants with a capacity of up to 200 MW, can be refunded.[5]

Recently, Schwarz et al. demonstrated that the optimal load factor is approximately 0.24–0.33, when electrolysers are exempt from grid fees (with an electricity price of 11–53 CHF/MWh$_{el}$). This results in a levelized cost of hydrogen (LCOH) of 1–6.7 CHF/kg$_{H2}$ with additional distribution and buffering costs of 1.8–1.9 CHF/kg$_{H2}$ (not including new infrastructure construction), leading to total supply costs of 2.8–8.6 CHF/kg$_{H2}$ or 84–258 CHF/MWh$_{LHV}$ (Schwarz et al., 2024). Bauer et al. found slightly higher hydrogen prices of 4.9–12 CHF/kg$_{H2}$ (147–360 CHF/MWh) in 2050, depending on the electricity price and the type of electrolyzer (Bauer et al., 2022). Estimations of VSG suggest 142 CHF/MWh without grid fees in 2045 (Decurtins, 2024). If this hydrogen were stored and converted into electricity (P2X2P), the electricity

[4] Art. 16 Swiss Energy Act

[5] Art. 14a para. 4 Federal Electricity Supply Act

price would increase due to an estimated levelized cost of storage (LCOS) of 45–60 CHF/MWh$_{H2}$,[6] a hydrogen-to-electricity efficiency of 60 % and the additional cost of generators to at least 200 CHF/MWh$_{el}$, but likely closer to 350–500 CHF/MWh$_{el}$.

It is interesting to note that, according to Schwarz et al., small electrolyser capacities in Switzerland can mostly be operated using cheap, 'surplus' electricity that would otherwise be curtailed. Larger capacities will eventually require the installation of dedicated electricity generators (e.g. more rooftop PV) and possibly dedicated short-term storage (e.g. batteries), as the available 'surplus' or 'cheap' electricity will be depleted. Adding dedicated electricity generators and short-term storage increases the price and leads to a negative production cost correlation, whereby higher hydrogen production volumes increase the cost per unit of hydrogen (Schwarz et al., 2024). The amount of 'surplus' cheap electricity available for domestic hydrogen production is expected to depend largely on the PV penetration rate (Schnidrig et al., 2024).

2.3.3. Availability and seasonal flexibility of biomass

The energy potential of biomass depends on the use paths, exploration policies, and the extent to which it is used for non-energy purposes, such as for construction. Guidati et al. estimate the sustainable potential of biomass in 2050 to be 26.9–32.1 TWh$_{LHV}$, of which 15–19.5 TWh$_{LHV}$ are due to dry fractions and the remainder are due to wet fractions (Guidati et al., 2021). A large proportion of this potential is already being exploited today. Fractions with unused potential include forest wood (about 35 % unused potential or 2.3 TWh$_{LHV}$/a) and manure (90 % unused potential or 6.7 TWh$_{LHV}$/a) (Strauss & Fischer, 2025; Thees et al., 2017). It is important to note that, unlike in other countries (e.g. Germany), Switzerland only permits the energetic use of 'waste' biomass and forest wood, not the cultivation of energy crops (BFE, 2009b).

The future potential of biomass is uncertain due to the effects of global warming and behavioural changes. Nevertheless, projections of dietary shifts suggest minimal changes in the potential for green waste and manure (Burg et al., 2019). Similarly, the availability of municipal waste fractions is also unlikely to decrease significantly (Birnstengel et al., 2018). However, changes in temperature and the hydrological cycle are predicted to affect the variety and quantity of available plant species, potentially impacting exploration policies (Strauss & Fischer, 2025).

A particular limitation of biomass is its dispersed accumulation and limited transportability. This factor is often not properly considered when assessing the use of biomass for energy purposes (e.g. by energy system studies) and adds to the challenge of exploiting the full potential of biomass. Conversion plants that digest or gasify wet biomass (especially manure) have a small collection area, resulting in low biogas output. The size of the biogas plant directly correlates to the CAPEX of the upgrading unit; below a certain size, upgrading biogas to biomethane and injecting it into the gas grid becomes increasingly economically challenging. As there can be acceptance challenges when sharing one larger biomass plant among multiple farms (Burg et al., 2021), ways must be found to incentivise larger plants (e.g. through better participation and utilisation of synergies; Gisler et al., 2024) or by clustering small biogas plants to centralise the upgrading unit (Bär et al., 2024). The cost of producing biomethane including transport ranges from 176 CHF/MWh (transport via the gas grid) to 214–355 CHF/MWh (transport by road) (Duttwiler et al., 2020).

Compared to manure, wood residues are easier to transport. Therefore, gasification plants could be a valuable option for producing renewable gas or liquid energy carriers in larger plants. Currently, and likely in the future, a significant proportion of the available dry biomass is used for purposes such as construction wood and space heating (Thees et al., 2017). Therefore, a change in usage may be necessary to obtain the required amount of wood to achieve the necessary input magnitude for the required plant scale.

[6] In the absence of CH-specific hydrogen storage cost data, methane storage costs in LRCs (15 CHF/MWh, based on Kober et al., 2024) were tripled to account for hydrogen's lower density and modestly increased further to reflect likely higher equipment costs.

Using biomass to produce negative CO_2 emissions adds to the complexity of finding the best exploitation strategy, but it could also strengthen the business case at high carbon prices, since all biomass conversion processes result in residual carbon. Connection to a potential future CO_2 network is likely to be feasible only for large, centralised biomass conversion plants due to added costs and complexity. However, for smaller plants, producing biochar or hydrochar may be more viable, as this has been shown to be compatible with biogas production (Atukunda et al., 2024).

Although detailed studies have been conducted on the regional availability of biomass (Mohr et al., 2019; Siegrist et al., 2022) and biomass transport (Schnorf et al., 2021), it is evident that the spatial consideration of biomass availability and the resulting small scale of biomass conversion plants poses considerable challenges to widespread exploration. This must be taken into account when developing optimal exploration strategies at a systems level to enhance its usefulness for seasonal purposes.

Assessment of the biomass potential for alleviating the seasonal challenge

As no studies have specifically assessed the potential of biomass to address the seasonal supply–demand challenge, back-on-the-envelope calculations (see Appendix 5.2) were conducted to estimate its potential in Switzerland under technological, economic, and spatial constraints.

Based on the back-of-the-envelope calculation, if biomass were prioritised for methane production, the estimated annual potential for methane production that could be fed into the gas grid is around 8.3 TWh_{CH4}. Literature values estimate 6–6.5 TWh_{CH4}/year (E-Cube Strategy Consultants, 2018; Thees et al., 2017), but these are only from wet biomass digestion/gasification of the total potential, not including wood gasification or infrastructure restrictions, which could explain the difference. The methane yield could increase by up to 2.3 TWh_{LHV} if hydrogen were used in summer to convert the residual CO_2 present in biogas/syngas into methane.

If the biomass potential is prioritised for electricity production, around 1.8 TWh_{el} of electricity can be produced in winter (3.6 TWh_{el} per year). A further 1.9 TWh_{el} of electricity could be saved if the waste heat replaced heat pumps. The electricity production potential is slightly below the upper potential of 4 TWh_{el} estimated by (VSE, 2018). With a gas storage of 1.5 TWh_{CH4}, winter electricity production could increase to 2.4 TWh_{el}, with a further 2.1 TWh_{el} saved through waste heat utilisation. Several options for further increasing winter electricity production are discussed in Appendix 5.2.

It is important to note that the values resulting from the back-of-the-envelope calculations are idealised due to the simplifications made in the calculations. Additionally, a significant proportion of the biomass considered available for the calculations is required for direct space heating or non-energetic uses (e.g. wood for construction). Therefore, achieving the presented gas/electricity production values would require a change in behaviour. Furthermore, the demand for industrial process heat (temperatures >400 °C) is projected to reach a minimum of 12 TWh_{th} per year by 2050 (BFE, 2021; Jakob et al., 2020). This suggests that if biomass were prioritised for biomethane production (including upgrading biomass with hydrogen), the resulting biomethane would not be sufficient to meet this demand alone. Nevertheless, the potential remains significant, and if utilised in a system-friendly manner, it could play an important role in mitigating the seasonal imbalance.

Studies have also been conducted on the seasonal flexibility potential of waste incineration plants, which is estimated to be around 200 GWh. However, due to the fact that high CAPEX plants (such as incinerators) benefit from high capacity factors, and load shifting reduces this factor, such load shifting is associated with higher costs (Dettli et al., 2014; Fuhrer et al., 2025). It is still uncertain whether it is more expensive to shift incinerator loads between seasons or to install a STES to shift summer heat production.

2.4 Transport and distribution of energy carriers

2.4.1. Electricity

Electricity distribution networks in Switzerland are largely well developed, especially in urban areas, and provide a strong basis for future needs, though local reinforcements are required due to variations in network strength (Bucher & Joss, 2023; Gupta et al., 2021). However, widespread deployment of smart grids is still lacking. Without them, peak demand and oversupply risks will necessitate costly grid expansion (Demiray & Ingold, 2024; Gupta et al., 2021; Schnidrig, Cherkaoui, et al., 2023; Schnidrig et al., 2024; Willemsen et al., 2022). Smart grids enable demand response and management of EVs, batteries, and PV systems, improving flexibility. Power-to-heat (and cold) will account for a significant proportion of electricity demand. When controlled intelligently and connected to STES, it can provide grid flexibility, reduce the need for grid extension while also reducing electricity demand in winter, as discussed in Chapter 2.2.1.

While the transmission grid is already relatively robust, local upgrades and possible voltage increases are needed in anticipation of future load growth, partly resulting from international electricity balancing. (Demiray & Ingold, 2024; Schnidrig, Cherkaoui, et al., 2023). Integration of STES and power-to-X technologies at higher grid levels can enhance flexibility. However, power-to-X benefits from a constant electricity supply in order to achieve a high load factor. Consequently, it is not a preferential technology for providing short-term flexibility (see Chapter 2.3.2).

2.4.2. Chemical energy carriers

The existing methane (natural gas) infrastructure is expected to remain in operation beyond 2050, potentially alongside a developing hydrogen network. However, the methane distribution system is likely to become less widespread, as most residential areas will switch to electrification or district heating (BFE, 2019). To boost biomethane production and ensure sufficient supply for storage, extending the gas grid to rural biomethane plants could help overcome the dispersed nature of biomass and its low transportability — especially for wet fractions.

The current gas infrastructure is incompatible with pure hydrogen due to material limitations, which require either repurposing or the construction of a parallel infrastructure (Bauer et al., 2022). In the short term, blending hydrogen into the gas grid is possible, although current regulations limit this to 2 %. Studies suggest that 20 % is feasible in distribution networks, and research is ongoing (Bordenet & Hafner, 2021; VSG, 2021).

The future of a hydrogen infrastructure in Switzerland remains uncertain, as it depends on domestic demand development and whether the country connects to the European Hydrogen Backbone (EHB) (Der Bundesrat, 2024). Although plans consider connecting Switzerland to the EHB by 2035 (European Hydrogen Backbone, 2024), the lack of formal international agreements and the unresolved legal situation regarding a hydrogen infrastructure in Switzerland render the timeframe very ambitious (see Chapter 2.6.2). Therefore, some energy system studies assume connection to the EHB will only be achieved in the 2040s (VSE, 2025b). The connection is also likely to depend on the outcome of bilateral negotiations, particularly the approval of the electricity agreement. If a connection is established, parts of the Transitgas pipeline will be repurposed for hydrogen where dual lines exist, with new construction elsewhere (Transitgas AG, 2025). Without connection, the construction of a large-scale hydrogen infrastructure is unlikely due to the high cost of domestic production and the subsequent need for large-scale storage. The federal government supports regulatory development and may offer guarantees, but it views industry as responsible for planning and building hydrogen infrastructure (Der Bundesrat, 2024). Currently, cantons oversee this infrastructure, yet a nationwide network would span multiple cantons, creating coordination challenges. To streamline technical and safety oversight, it would be more effective for the federal government to hold jurisdiction (Beretta, 2022).

To support dynamic grid stabilisation, future methane or hydrogen storage facilities should be located near gas transmission infrastructure and major consumers. Large consumers, such as backup generators, should ideally be located where both the gas and high-voltage electricity networks are strong to enable efficient integration. More broadly, the strategic placement of seasonal storage and related technologies can enhance system efficiency and minimise the need for costly grid expansions.

2.5 Imports

When discussing imports, it is important to distinguish between dependence, supply security and resilience. A system can be highly dependent on imports yet still ensure supply security and be considered resilient if it has several months' worth of diverse supplies stored domestically. This can increase the ability of energy systems to withstand temporary import disruptions and unpredictable shocks. Currently, Switzerland can withstand several months of interruptions to liquid fuel imports due to its emergency reserves, which are likely to be maintained due to the low storage costs (although these will eventually be switched to carbon-neutral fuels). In contrast, gas imports can currently only be buffered for less than a day using domestic short-term storage and grid inertia (WWF, 2018), and for approximately two months using secured storage in neighbouring countries at current demand levels. If the planned LRC for gas storage is realised alongside storage abroad, the security of supply and resilience of the gas network could increase further, as more potential gas sources would be available in case of emergency for a certain period of time. Switzerland's electricity self-sufficiency in March (when storage lake fill levels are at their lowest) is currently 26 days (ElCom, 2025). However, to maintain acceptable supply security in the near future — which, according to the Federal Council, would be achieved if Switzerland could self-supply for at least 22 days in March — additional reserve plants are required (up to 1.9 GW by 2035). The demand for reserve capacity beyond 2035 is highly uncertain (ElCom, 2025). Such reserve plants can usually run on both gas and liquid fuels, further increasing resilience if both sources are stored domestically. In addition to reserve plants, installing considerable short-term storage capacity, such as batteries, would further increase supply security and resilience.

Both short- and long-term storage can enhance resilience, regardless of import dependence. It may even reduce dependence by enabling the more efficient use of domestic energy (e.g. by reducing PV curtailment). However, determining the optimal storage capacity requires balancing resilience, import dependence and import costs against the costs of expanding storage and domestic generation, which is partly a political/societal question.

2.5.1. Electricity

Results of optimisation models predict a continuation of electricity exchange with a net electricity import of 6–9 TWh_{el} per year in 2050 in the cost-optimal base scenario, with the deficit occurring mainly during the winter months (BFE, 2021; Marti et al., 2022; Panos et al., 2021). However, the Electricity Act adopted in 2024 stipulates that total winter imports should not exceed 5 TWh_{el}.[7] Meeting this ambitious target will require a rapid expansion of renewable electricity generation, particularly wind power (and some alpine photovoltaics), in Switzerland. Otherwise, larger volumes of gas will need to be imported to compensate (VSE, 2025b). Reliable electricity imports, particularly in the event of a shortage, require full integration into the European electricity and balancing markets, necessitating an electricity agreement with the EU. Otherwise, the capacity to import electricity during periods of high demand is reduced, which could result in supply issues (Frontier Economics, 2021; Weigt et al., 2022).

Projections by the ENTSO-E model indicate that wind capacity will account for a significant proportion of the European electricity mix in the coming decades, particularly in coastal regions where high winter electricity production is anticipated (ENTSO-E, 2024). However, the European electricity grid requires further reinforcement and reliable market balancing platforms (e.g. TERRE, MARI and PICASSO) to prevent congestion and balance the grid over different timescales (ENTSO-E, 2023). It remains uncertain whether the planned timeframe for implementing these grid reinforcements can be met, but the need for them is recognised, and efforts are underway to address this challenge. Given the investment in PV in neighbouring countries, net electricity exports during the summer are unlikely. However, imports and exports on an hourly/daily basis are likely to continue, also for balancing purposes, using Swiss PHES and potentially other price competitive short-term storage.

Dark doldrums (‘Dunkelflaute’) events can occur with duration of up to several days to weeks. These events tend to be concentrated in individual regions rather than across the entire European continent,

[7] Art. 2 para. 3 Swiss Energy Act

allowing for some trans-European balancing of generation shortfalls (Li et al., 2021), provided a grid expansion takes place. During these periods in winter, imports into Switzerland are likely to be uneconomic due to very high electricity prices in Europe. Conversely, there is an incentive to export electricity from Swiss hydropower plants to balance the European electricity system (which is already happening today). It can therefore be assumed that imports will typically take place at non-critical times in the European electricity system, with hydro and possibly back-up generators providing electricity at more critical times (Weigt et al., 2022).

2.5.2. Chemical energy carriers

The estimated import volumes of chemical energy carriers in 2050 vary considerably depending on the expected import prices. Estimates range from 10.5–26 TWh_{LHV} (gases and fuels; BFE, 2021; Panos et al., 2021) and an additional 17–22 TWh_{LHV} of sustainable aviation fuels (SAFs) (BFE, 2021) in 2050, with cost estimates of importing carbon-neutral chemical energy carriers ranging from 50–320 CHF/MWh.

Import prices for hydrogen are expected to be at the lower end of the range, at around 50–160 CHF/MWh_{LHV} ((Bauer et al., 2022); 1 Euro ~ 1 CHF in 2022). However, energy system model studies usually assume import costs of between 120 CHF/MWh_{LHV} (Akbari et al., 2024; VSE, 2025b) and 160 CHF/MWh_{LHV} (Panos et al., 2021). For import, however, a connection to the EHB is required, as discussed in Chapter 2.4.2.

The estimated import costs of biogas[8] are 88–132 CHF/MWh (BFE, 2021; Panos et al., 2021) and 160–290 CHF/MWh for e-methane (Akbari et al., 2024; BFE, 2021). Existing pipeline infrastructure can be used for these imports. While some studies estimate the import potential of biomethane to be 13.3 TWh_{CH_4} (BFE, 2021), others assume that there will be no availability of imports (VSE, 2025b). If Switzerland is fully integrated in the respective markets, it will likely be a question of price. However, a proof-of-origin international clearing system is required, as well as regulatory changes in Switzerland to exempt grid-bound virtual renewable gas imports from the CO_2 levy (Gugger, 2021). Another option is to import fossil NG and use carbon capture and storage (CCS) to reach carbon neutrality. Cost estimations put the cost of NG imports at 24 CHF/MWh_{LHV} in 2050 (BFE, 2021). With CO_2 sequestration, transport and storage costing an additional 180 CHF/t_{CO_2} (Albicker et al., 2023), the total cost of NG would be around 60 CHF/MWh_{LHV}. However, this option would require a CO_2 transport and storage infrastructure, which does not yet exist. Additionally, plants with carbon capture units require significantly higher CAPEX (Elias et al., 2018) which incentivises higher capacity factors (shifting towards base-load plants rather than backup generators) and lower electrical efficiency (Vasudevan et al., 2016).

The import of solid wood for energy use could continue as it is today (BFS, 2024; Strauss & Fischer, 2025). As climate change becomes more severe, Switzerland's dependency on wood imports will increase, as will the uncertainties in the international wood market (Spörri et al., 2023).

Despite their easier handling, liquid energy carriers are expected to be slightly more expensive to import than gases, with estimates ranging from 120 CHF/MWh_{LHV} (Power-to-Diesel; Boulouchos et al., 2022) to 320 CHF/MWh_{LHV} (Biodiesel and Power-to-Diesel; BFE, 2021). In particular, sustainable aviation fuels (SAFs) cannot be produced in Switzerland in the required quantities due to a lack of the necessary amount of cheap primary energy, so they will mostly have to be imported (BAZL, 2022).

Compared to the estimated supply costs of 84–258 CHF/MWh_{LHV} for domestically synthesised hydrogen (Schwarz et al., 2024) and 176 CHF/MWh_{LHV} for biomethane (Duttwiler et al., 2020), these import prices appear attractive, especially since the lower range of prices for synthesised hydrogen applies to small quantities using very cheap electricity (see Chapter 2.3.2 for a detailed discussion). However, all prices are still subject to a high degree of uncertainty. Furthermore, (seasonal) variation in gas import prices would be crucial for developing business cases, but no projections are yet available. Since production routes for liquid fuels benefit particularly from economies of scale and large amounts of cheap energy

[8] Both sources refer to 'biogas' as an import option. It is assumed that biomethane is meant (in this report biogas = CH_4 + CO_2, biomethane = CH_4).

(both of which are limited in Switzerland), it is inconceivable that a significant proportion of liquid fuels will be produced domestically. Hence, the majority of liquid fuels will have to be imported. As mentioned at the beginning of the chapter, it may be beneficial to maintain or establish import buffers (particularly for liquid fuels) to increase resilience.

2.6 Related aspects

2.6.1. Energy markets and incentives

Carbon-neutral chemical energy carriers can only compete with fossil fuels if greenhouse gas emissions are properly priced through an effective carbon price. This is especially important for the economic viability of seasonal storage technologies, as they face competition from the low cost of easy to store fossil fuels. The CO_2 levy in Switzerland is set at a maximum of 120 CHF/t_{CO2} for thermal fuels. Large emitters with an approved decarbonisation strategy and motor fuels are exempt from the levy (BAFU, 2024). Switzerland is also linked to the European Emissions Trading System (EU ETS), which sets a price for CO_2 in a market environment. The current carbon price in the range of 50–100 CHF/t_{CO2} is insufficient for a successful transformation. Estimates for developed countries suggest that the necessary price will be 200–250 CHF/t_{CO2} in 2050 (Boulouchos et al., 2022), based on (IEA, 2021). However, future changes to the ETS, such as expansion to other sectors (e.g. buildings and road traffic), a faster reduction in the number of available certificates, the elimination of free certificates, and the introduction of a carbon border adjustment mechanism (CBAM), could significantly impact carbon prices. Nevertheless, the measures currently implemented in Switzerland are considered insufficient to achieve carbon neutrality by 2050 (IMF, 2023).

Seasonal variability in electricity prices is a key enabler for the deployment of seasonal storage. Technologies such as power-to-heat with STES benefit economically from stable and significant seasonal price differences. While the future Swiss electricity mix is expected to produce such differences, the broader European mix may exhibit less pronounced seasonal patterns. If an electricity agreement with the EU exists, imports could flatten Swiss price variations, though the extent of this effect is uncertain — especially if winter imports are actually capped at 5 TWh_{el}. In contrast, the absence of an agreement would likely lead to more pronounced seasonal price signals.

It remains unclear what level of seasonal price difference is necessary for specific storage technologies to become cost-effective, or whether alternative solutions to balance seasonal supply and demand (see Chapter 1) are more viable and scalable. Although dynamic pricing exists on the wholesale market, most Swiss end users still face static tariffs. Some utilities (e.g., Groupe E's 'Vario' tariff) already offer dynamic rates, but broader adoption may depend on regulatory changes, such as market liberalization — a likely condition for an EU electricity agreement. Clear rules ensuring stability and fairness would be essential. In the meantime, large-scale storage operators can already benefit from seasonal price variance, whereas small consumers face limited incentives to invest in either short- or long-term storage options like BTES due to fixed electricity rates.

Significant long-term (seasonal) gas price differences will incentivise large-scale gas storage. In the Swiss market, such a price pattern is likely to emerge due to coupling with the electricity and heating sectors (through production and/or demand). While the future variability of import prices remains uncertain, the continuation of a seasonal price pattern for imports would not be unexpected given the seasonal fluctuations in heating demand in Europe (via CHP plants and backup generators, for example).

Seasonal storage often relies on large, long-lived infrastructures such as district heating networks and gas pipelines, making long-term investment security critical. However, the absence of a clear, binding path to carbon neutrality increases investment risk, particularly for technologies involving chemical energy carriers, where future price, demand, technological progress, and regulatory frameworks remain uncertain (IMF, 2023; Wenger et al., 2022). Although risk-mitigation strategies exist that preserve incentives for renewable energy producers (e.g. Schlecht et al., 2024), they have not yet been adapted to seasonal storage technologies or infrastructure providers.

A comprehensive Swiss energy reserve market across all time scales, where resilience holds tradable value, could support the development of seasonal storage technologies. However, its benefits relative to the current reserve system[9] remain uncertain, and key regulatory questions — such as service quality standards, market fairness, infrastructure access, and social equity — are unresolved. While concepts to enhance electricity sector resilience exist (Perner & Janssen, 2017), a holistic reserve market including chemical energy carriers and STES is lacking. Such a market could offer new business models for seasonal storage by enabling revenue through capacity withholding and thereby reducing reliance on seasonal price fluctuations for economic viability.

2.6.2. Regulatory aspects

The market-related issues raised in previous sections require regulatory changes. These include proper pricing of externalities, clear market rules for dynamic electricity pricing, rules/schemes to reduce investment risk, and potentially rules for a comprehensive reserve market.

Although seasonal storage systems (e.g., STES) may hold national importance comparable to renewable energy infrastructure, the specific types and scales required to attain this status remain undefined. In addition, while STES does not necessarily need to be included in the structure plan ('Richtplan', at cantonal level), proactively including such technologies in these plans would facilitate planning, for example by enabling the early clarification of environmental impacts and land use (Abegg et al., 2025). Regarding land use planning ('Nutzungsplanung', at municipal level), STES construction is already possible, but requires above-ground storage (e.g. PTES), either to be built on expensive building land or to have a special permit for construction in an agricultural zone subject to further restrictions. Such a permit would be easier to obtain if STES were explicitly mentioned in the Spatial Planning Act ('Raumplanungsgesetz', federal level), which currently only covers district heating pipelines in its latest revision (Abegg et al., 2025). Underground STES (ATES, BTES) face fewer regulatory challenges in terms of land use, as the land above can generally be used. However, the groundwater temperature may only be changed by a maximum of 3 °C[10] to protect the underground ecosystem and water quality. Exceptions can only be made on a 'narrow local basis'. While this rule is understandable for oxygen-rich underground areas, it appears too restrictive for oxygen-poor areas (some aquifers), which tolerate much higher temperature changes. The Federal Office for the Environment (FOEN) is currently drafting a proposal to revise the requirements. This ongoing revision will also clarify that an environmental impact assessment is not required for STES.

Hydrogen is not properly implemented in current regulations, but initial processes to develop technical and market regulations for its transport and storage are underway (Der Bundesrat, 2024). If the potential hydrogen infrastructure and market are to be established anywhere near the timeframe envisaged in the Hydrogen Strategy, the development and implementation of regulations is particularly urgent. Furthermore, the rapid development of hydrogen regulations within the EU poses a risk of further regulatory divergence, which could make future agreements for connection to the EHB (e.g. regarding certificates of origin and the international trading system) increasingly challenging (VSE, 2025a). It may therefore be useful to include hydrogen-related agreements in a potential future electricity agreement with the EU, as mentioned in the Hydrogen Strategy. A roundtable discussion on gas storage has also been suggested to explore its potential and the next steps (Der Bundesrat, 2024). The regulations regarding hydrogen and other gases will likely be integrated into a new Gas Supply Act (GasVG), which is currently under development.

Methanol is currently considered a 'chemical' rather than an energy carrier. This has resulted in limitations in terms of maximum storage size (2.000 kg) and disadvantages compared to other energy sources, such as taxes and measurement in litres instead of kilograms (Schaffner, 2022).

According to the provisions of the Biomass Strategy, priority should be given to the cascading use of biomass, provided that food production and biodiversity are not compromised (BFE, 2009b). While

[9] The reserve system is still being conceived; the winter reserve ordinance is limited in time till the end of 2026; the obligatory hydro reserve is already implemented in the Electricity Supply Act; rules for a thermal electricity reserve were recently approved.

[10] Annex 2 para. 21 Waters Protection Ordinance

recognising the importance of biomass as a potential asset in promoting energy independence, the Strategy abstains from advocating the large-scale cultivation of energy crops. Furthermore, the cascading use of biomass is currently barely established in Switzerland (Thees et al., 2017), and there are no nationwide incentives to encourage its use for applications requiring high-exergy energy (Vuille et al., 2023). Both of these factors would increase the value of biomass within the system. A comparison with other European countries shows that Switzerland provides relatively low subsidies for biomethane plants, both direct and indirect (through CO_2 tax avoidance). This has a low impact on the total costs of biomethane plants, meaning these subsidies have little effect on scaling up production. Furthermore, only biomethane plants receive subsidies, not hydrogen or hydrogen derivatives from biomass conversion (Decurtins, 2024). There are also regulatory changes required to exempt renewable gas imports from the CO_2 levy (Gugger, 2021).

2.6.3. Social acceptance

Most individual decisions are influenced not only by technical and economic factors but also by ideology, informal communication, limited or inaccurate understanding of the energy system, risk perceptions, NIMBY opposition, political framing, and other factors (Stadelmann-Steffen et al., 2018). Public support for a project increases when perceived personal benefits outweigh the costs. These benefits and costs extend beyond economics to include perceived risks, ideologies, and levels of public participation in decision-making (Gisler et al., 2024). As energy systems become increasingly complex, the public faces growing challenges in grasping their interrelationships holistically. This can hinder the adoption of new technologies due to insufficient support and difficulties in evaluating trade-offs. However, the impact of limited system understanding on social acceptance, and its broader implications for the energy transition, remains to be fully assessed (Stadelmann-Steffen et al., 2018).

The population views increased energy independence favourably (gfs.bern, 2023). However, acceptance of the various seasonal storage technologies (and related technologies) that can increase energy independence varies:

- Large hydroelectric dams generally enjoy strong public support (Stadelmann-Steffen et al., 2018), but new construction projects face acceptance challenges, mainly due to ecological impacts, but also in cases of foreign ownership (Tabi & Wüstenhagen, 2017).
- Due to the lack of large-scale STES in Switzerland, acceptance has not yet been properly assessed. Nevertheless, an initial quantitative survey revealed that providing further information on STES to participants who were largely unfamiliar with the technology influenced their acceptance (Sträter et al., 2025). Hence, the acceptance of these technologies could change significantly if they become better known.
- Currently, there is no information available regarding the social acceptance of LRCs and the local production of chemical energy carriers, except for biomass digestion. Here, high financial compensation and ownership of biogas plants favour farmer acceptance (Burg et al., 2021).
- Acceptance of the necessary construction of new storage related infrastructure (e.g. pipelines, electricity grid and conversion plants) can be affected by its fit with the landscape, local added value and the level of public participation (Gisler et al., 2024; Wissen Hayek et al., 2019).
- District heating (and cooling) networks are less widely accepted in Switzerland compared to other countries, such as Denmark. However, acceptance varies regionally, with significantly higher levels in areas where district heating networks are already in place (Oppermann et al., 2022).
- In terms of energy market instruments relevant for seasonal storage (see discussion in chapter 2.6.1), pricing CO_2 has proven to be a notoriously difficult challenge, but there are approaches that can address this issue (Fremstad et al., 2022). Dynamic electricity tariffs combined with appropriate bonuses and penalties can also be developed to achieve higher acceptance of such tariffs (Balthasar & Schalcher, 2020).

3 Research needs and recommendations for action

This chapter lists and describes the knowledge gaps and corresponding research needs as derived from the current state of knowledge presented in Chapter 2. This chapter also explains the rationale behind these needs and provides estimates of when the corresponding knowledge gaps should be closed to ensure that the goals of the Energy Strategy can be reached. Finally, this chapter classifies the significance of closing the gaps for the desired development of the energy system, as well as the uncertainty associated with the significance. The knowledge gaps are grouped by topic and ranked according to their urgency, from high urgency (high significance and low uncertainty) to low urgency (low significance and high uncertainty). The knowledge gaps with the lowest urgency are not presented below, but collected in Appendix 5.1.

The knowledge gaps, from which the related research needs and recommendations for action were derived, were compiled from the following activities:

- Knowledge gaps were explicitly asked for during expert interviews.
- A questionnaire was sent to experts, challenging the reasonableness of the current state of knowledge from the literature and explicitly asking about knowledge gaps relating to seasonal storage technologies and related energy infrastructure.
- The initial knowledge gaps identified through expert input and literature reviews were summarised in an initial draft report on the state of knowledge, which was then sent to experts for feedback on the gaps.
- Based on the feedback from the first review, a workshop was organised to discuss knowledge gaps and their significance for storage technologies and related aspects (infrastructure, imports, etc.). The workshop output was synthesised and sent back to the participants for checking.
- Based on the workshop and previous activities, a draft of this report was prepared and circulated to experts for assessment of the included knowledge gaps.
- Based on expert feedback on the draft, the final version was written.

Fifty experts from twenty research institutions in Switzerland were involved. Most of the knowledge gaps identified were synthesised from several expert opinions and contextualised by the author's understanding of the topics associated with the gaps, which was obtained while working on the current state of knowledge presented in Chapter 2. These gaps were then converted into research needs and/or recommendations for action, accompanied by a brief explanation of the context and motivation. Where possible, reference is made to the literature in which a knowledge gap has been identified.

Additional information accompanies each knowledge gap, containing notes about the timeframe, the significance for seasonal storage, the uncertainty surrounding this significance, the relevant topics affected, the sources of information and similar research needs. The definitions of each segment are as follows:

- **ID:** Each knowledge gap is given a specific ID to allow for referencing (see second-to-last point).
- **Timeframe:** Indicates when the knowledge gap should be closed to support the development of seasonal storage. Since Switzerland aims for a sustainable energy system by 2050, many gaps must be addressed well before then—either because results need to become market-ready in time or because they form prerequisites for further development. Considering this, the authors estimated the timeframe within which the knowledge gap needs to be closed. While acknowledging that every knowledge gap should ideally be closed immediately, a slightly later timeframe was given to those that were deemed to be less time-critical.
- **Significance**: Provides an estimate of the impact that closing the knowledge gap would have on the value added by seasonal storage to the energy system. High significance indicates that

closing the gap would add significant value to the energy system, e.g. reducing system costs, increasing efficiency and resilience, etc., in line with the Energy Strategy 2050.

- **Uncertainty**: Indicates the likelihood that the significance will change in the future. High uncertainty indicates a high probability of change.
- **Topics**: Indicate topics that are affected by the knowledge gap, both in terms of potential impact and in terms of tools to address the knowledge gap.
- **Based on**: Indicates the number of experts who have supported the knowledge gap. If the knowledge gap has been addressed in the literature, a reference is provided. If the knowledge gap was not specifically mentioned by the experts but identified by the authors while researching and writing the report, it is denoted as 'own deduction'.
- **Similar IDs**: Similar knowledge gaps are often addressed in combination with different technologies or in different contexts, so similar knowledge gaps, which are not part of the respective group (subchapter), are listed by their ID.
- **Comments**: Ongoing initiatives/projects to close the knowledge gap are referenced here.

3.1 Energy market

3.1.1. Identify seasonal storage friendly market model

Design new market models or identify the necessary changes to existing models to integrate different types of short- and long-term energy storage technologies and related infrastructure in a way that is attractive to investors, system-friendly and maximises social welfare. This includes identifying the effects of different market designs on seasonal storage and related infrastructure in terms of economic performance, potential business cases, system friendliness and social impacts. A particular focus should be placed on investment decisions under highly volatile prices. Furthermore, identify necessary changes that cannot be achieved through the energy market (alone) and for which other solutions must be found (e.g. public-private partnerships for e.g. long-term investments). Finally, based on the potential changes to market designs that have been identified, ways must be found to test and implement those changes.

Rationale: Current market models were not explicitly developed with sector coupling and the operation and interaction of short- and long-term storage in mind under highly dynamic pricing conditions. Changes are needed for a successful, system-friendly and fair integration of sector coupling and storage technologies. While there are ideas for new electricity market designs (Perner & Janssen, 2017), the potential structure of a market for the highly sector-coupled energy system remains unclear. Such a market would incorporate short- and long-term thermal and chemical storage in order to enable multi-vector flexibility, consider the implications for social welfare and take the (future) CO_2 market into account. Highly dynamic prices, including periods of zero or negative electricity prices, could significantly impact investments in power and heating plants, and should be represented in detail in system models when assessing market models and the future energy system. Although the energy market is an effective instrument for allocating supply and demand in the short term, long-term developments and transformations can lead to coordination and innovation failures that may necessitate alternative implementation methods extending beyond the energy market's scope, particularly for large infrastructures with long return-on-investment durations in unclear market situations.

*ID: 1 | Timeframe: **2025-2035** | Significance: **High** | Uncertainty: **Low** | Topics: Economy, Regulations, Society | Based on: Multiple expert opinions (9) | Similar IDs: ID: 10, ID: 17, ID: 22, ID: 29*

3.1.2. Reduce investment uncertainty

Find ways to address investment uncertainty and reduce barriers to seasonal storage technologies and related infrastructure. This includes identifying 'no-regret' decisions regarding different technologies and infrastructure for seasonal storage, taking into account potential future market models and different import prices. It also involves finding appropriate ways to overcome high initial costs and investment uncertainty.

Rationale: For storage technologies to be scaled up at an appropriate pace, investors require reliable information regarding investment uncertainty and risk. Additionally, policymakers must understand which investments would benefit the energy system under various future scenarios, enabling them to develop regulatory frameworks that incentivise such investments. Alongside implementing a clear and binding pathway to carbon neutrality and fair dynamic energy pricing rules — an important prerequisite for developing business cases — contracts specifically designed for seasonal storage and related infrastructure should be developed and optimised to reduce risk without distorting incentives. Such contracts are currently being developed for renewable electricity generators (Schlecht et al., 2024), but not yet specifically for seasonal storage and related infrastructure.

*ID: 2 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Economy | Based on: Multiple expert opinions (4) | Similar IDs: ID: 5, ID: 9, ID: 8, ID: 33.*

3.1.3. Test local markets

Test new market models in local energy communities (with e.g. STES) under real conditions as part of large-scale pilot projects.

Rationale: Real-world testing is needed to benchmark market models. This is necessary to fine-tune regulations, gain social acceptance and participation, find the best way for prosumers and integrators (such as utilities) to interact, and test how different technologies work together in a market environment. This is particularly important for short- and long-term TES, which can reduce electricity demand in winter and absorb surplus electricity in summer.

*ID: 3 | Timeframe: **2030-2035** | Significance: **High** | Uncertainty: **Low** | Topics: Economy, Society, Pilots | Based on: Single expert opinion (1) | Similar IDs: ID: 7, ID: 10, ID: 15, ID: 27.*

3.2 STES implementation

3.2.1. Integrate STES in space-constrained areas

Strategies are needed to integrate STES into space-constrained urban environments. This includes identifying cost-effective approaches for retrofitting existing buildings, enabling multi-purpose use of PTES surfaces, and repurposing existing or abandoned infrastructure — such as artificial caverns, tunnels, or cellars — for thermal storage. Pilot projects should be implemented to test these concepts under real-world conditions, evaluate social acceptance, and demonstrate technical and economic viability to investors.

Rationale: Due to the limited transportability of heat and the high heat demand in dense urban areas, it is crucial to find efficient and cost-effective ways to integrate STES in these areas if these technologies are to be widely adopted. Although initial concepts are available, such as horizontal drilling for BTES and converting cellars or tunnels for CTES, these are still in the early stages of research.

*ID: 4 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Economy, Society, TRL increase | Based on: Multiple expert opinions (4) |Comments: Researched by SwissSTES flagship project.*

3.2.2. Clarify regulatory situation for STES

Several regulatory barriers and ambiguities surrounding STES should be removed or clarified to reduce implementation barriers. In particular, the rules on changes to groundwater temperature of up to 3 °C should be reconsidered, with exemptions formulated for cases where larger changes are justifiable. Additionally, several open questions regarding spatial planning remain unanswered due to the lack of explicit mention of STES in related documents (e.g. Raumplanungsgesetz). These issues should be clarified in relation to STES, or STES should be properly included in these documents. Furthermore, to facilitate nationwide implementation, coordination between the cantons is needed (e.g. via EnDK or MuKEn) to harmonise rules and legal procedures.

Rationale: STES are not yet explicitly included in the regulatory framework. This often leads to unclear situations and creates additional hurdles for investors in the form of time-consuming clarification processes. These processes should be streamlined to enable shorter project durations and reduce financial risks.

*ID: 5 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Regulations | Based on: Multiple expert opinions (3), (Abegg et al., 2025), (IG Zyklos, 2022) | Similar IDs: ID: 31 | Comments: A proposal for clarifying the most important ambiguities is currently being drafted by FOEN.*

3.2.3. Properly integrate STES in energy system models

To assess the realistic storage capacity potential and the optimal storage type at each location, a detailed representation of STES in sector-coupled national energy system optimisation models should be developed. This should include consideration of space constraints for STES installation (using GIS-based modelling) nearby waste heat sources, heat demand, short-term thermal storage and charge/discharge dynamics (for short-term electricity uptake and peak shaving in DH grids), as well as intelligent control strategies.

Rationale: As most national energy system models do not properly implement STES, it is difficult to make robust statements about storage capacity and the impact on the energy system, such as the potential for winter electricity savings and additional system benefits. Benchmarking the system services of STES against alternatives such as electrolysers for capturing surplus electricity and CHP plants for meeting peak heat demand in district heating networks would require a model of this kind. Although studies have examined the availability of waste heat in relation to heat demand, the implications of STES integration have yet to be assessed (Burg et al., 2023)

*ID: 6 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Energy Models | Based on: Multiple expert opinions (3), (Forum Energiespeicher Schweiz, 2024) | Similar IDs: ID: 16, ID: 27, ID: 28, ID: 35 | Comments: SES ETH model and STEM consider STES, but not very detailed.*

3.2.4. Adapt international knowledge to Swiss circumstances

Insights from international STES projects, particularly PTES, ATES and BTES, should be adapted to the Swiss context by evaluating their compatibility with local regulations, societal acceptance and existing heat infrastructure. These findings should then be validated through pilot projects, which would identify any operational challenges and demonstrate the technologies' feasibility to investors and policymakers.

Rationale: Most STES are mature technologies that are already in operation in other countries. However, it is unclear how well existing knowledge can be transferred to a Swiss context in terms of legal, economic, technical and social aspects. Pilot projects could explore this and also increase visibility among local investors, contributing to a faster and broader uptake of these technologies in Switzerland. While the first BTES have already been installed in Switzerland (e.g. at ETH Hönggerberg), particularly larger ATES and PTES are not yet in operation.

*ID: 7 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Economy, Regulations, Pilots | Based on: Multiple expert opinions (2).*

3.2.5. Explore subsurface for storage purposes

Better information is needed on the suitability of the (deep) subsurface for ATES.

Rationale: The geological conditions, and therefore the suitability of the deeper subsurface for large-scale ATES, are largely unknown. This requires significant initial exploration costs for each project, which limits their attractiveness and uptake. A more comprehensive survey of the subsurface, particularly at sites with higher heat demand and/or large heat sources, could systematically identify suitable geological conditions and thus reduce these barriers. As the cantons are the competent authorities for the subsurface in Switzerland, their stronger involvement in facilitating the development of openly accessible regional groundwater models for major aquifer systems should be promoted. These models could be used to efficiently simulate heat flow and thermal storage conditions and/or derive high-resolution local models.

*ID: 8 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low – Medium** | Topics: Economy | Based on: Multiple expert opinions (3), (EGK, 2022) | Similar IDs: ID: 34 | Comment: The federal council was assigned to develop a program for nation-wide exploration of the subsurface (Motion 20.4063).*

3.2.6. Develop guide for STES implementation

Develop a guide to support project developers in the selection and implementation of the most suitable STES technology, adapted to the specific conditions of each project — including capacity needs, geographical and geological factors, cost, and temperature requirements. The guide should also provide detailed information on regulatory frameworks and permitting procedures to ensure that legal and administrative requirements can be addressed from the early planning stage. Given the critical role of social acceptance in the success of STES projects, the guide should also emphasize strategies for early stakeholder engagement and project design approaches that foster public support and alignment with local community interests.

Rationale: The selection and implementation of STES at specific sites can be challenging due to local peculiarities. These complexities may hinder the broader adoption of STES technologies. To support project developers, guidance is needed to identify the most suitable storage technologies for a given context and to assist with the design, planning, and efficient operation of systems within relevant regulatory, geographical, geological, and societal constraints. At present, no such guide exists.

*ID: 9 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low – Medium** | Topics: Economy | Based on: Multiple expert opinions (2).*

3.2.7. Incentivise borehole regeneration

Effective incentive mechanisms should be determined to regenerate BTES to higher temperatures in summer in order to maximise electricity savings in winter. In particular, the potential of dynamic electricity tariffs to promote the use of surplus PV electricity for regeneration should be investigated. Additionally, research should explore how alternative heat sources, such as solar thermal energy and waste heat, can be efficiently integrated along with heat pumps to charge BTES in a system-friendly manner. The integration of BTES into district heating networks also demands in-depth studies to assess the technical, economic and operational implications.

Rationale: There are currently no clear incentives or rules in place to encourage BTES to operate in a system-friendly manner in both winter (discharging) and summer (charging). Such incentives would encourage the use of BTES to absorb surplus PV electricity (from one's own roof or from the local energy community) in summer, which could potentially reduce PV curtailment and discourage operation during short-term electricity shortages. This would help to reduce the load on distribution grids. The integration of BTES into district heating networks has also been little explored due to its limited heat transfer capacity. Further exploration and optimisation of optimal network integration together with buffer storage is needed for wider, cost-effective implementation.

*ID: 10 | Timeframe: **2025-2030** | Significance: **Medium – High** | Uncertainty: **Low** | Topics: Economy, Regulations | Based on: Multiple expert opinions (2) | Similar IDs: ID: 1, ID: 3.*

3.2.8. Further explore novel STES technologies

Further research into novel seasonal thermal storage materials is needed to find optimal solutions for specific needs and circumstances. This includes identifying and refining new, non-toxic, inexpensive and easy to handle phase change materials (PCMs) with phase changes at temperatures of around 10–20 °C and around 50–70 °C, for energy storage both at ambient and direct use temperatures. In addition to sensible and latent thermal storage, sorption storage concepts should also be further developed, particularly for space-constrained applications.

Rationale: The low energy density of sensible STES poses many challenges, but higher-density STES would facilitate implementation and retrofitting in dense areas. Latent STES with a phase change of around 10–20 °C would allow heat pumps to be used more efficiently for heating purposes than with current ice storage systems. Latent STES could be combined with large sensible STES, such as PTES, to increase energy density and stabilise output temperatures. Sorption storage enables efficient high-density storage without the need for significant electricity input during discharge. While such concepts exist, they are still in the experimental phase, with questions remaining regarding technical details, economic viability, and regulatory hurdles.

*ID: 11 | Timeframe: **2030-2040** | Significance: **Medium** | Uncertainty: **Low – Medium** | Topics: TRL increase | Based on: Single expert opinion | Comments: PCM and sorption storage are being researched in the SwissSTES flagship project.*

3.3 Biomass usage

3.3.1. Identify merit order of biomass usage

A clear understanding of the 'merit order' of uses of available biomass fractions should be developed, taking into account not only energy use but also negative emissions, construction sector, environmental services, spatial distribution, etc. Based on this understanding, rules should be developed to regulate use at national level.

Rationale: While biomass has the potential to address seasonal energy imbalances, its optimal use remains unclear, particularly in the context of competing energy and non-energy applications. Although the Biomass Strategy provides a foundation, it does not give sufficient consideration to climate change mitigation and negative carbon emissions. Additionally, existing objectives, such as the cascading use of biomass (i.e. first for construction, then for heating/electricity production and finally for negative emissions), are not adequately enforced by current legislation. A comprehensive assessment is needed to determine how biomass can deliver the greatest societal benefit, which may not lie in alleviating the seasonal energy challenge. Therefore, a smart utilisation strategy should be developed for biomass allocated to energy use, as part of a cascading use approach. This would maximise system value and account for co-benefits, such as negative emissions. To shift existing usage patterns towards more optimal pathways, regulatory measures and targeted incentives are essential.

*ID: 12 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Regulations, Society, Environment | Based on: Multiple expert opinions (4), (Thees et al., 2023).*

3.3.2. Develop strategies for energetic biomass usage

Develop strategies for the optimal energetic use of biomass across competing applications and processes — such as digestion, gasification, on-site combustion, grid injection, or negative emissions — informed by national, sector-coupled energy system models. These strategies should account for spatially resolved biomass availability, conversion technologies, transport infrastructure, exergy efficiency, local energy demand, infrastructure costs, regulatory constraints, and social acceptance.

Rationale: Optimising biomass exploration for energy purposes in light of seasonal challenges can increase the availability of storable, bio-based chemical energy carriers (e.g. biomethane) and optimise the use of storable biomass (e.g. wood) for alleviating the seasonal imbalance. Although detailed estimates of regional biomass availability and transport potential are available (Mohr et al., 2019; Schnorf et al., 2021), optimal exploitation pathways from a system perspective, based on energy system models are still lacking. Such an analysis should also consider new technologies, such as hydrothermal and wood gasification/liquefaction, as well as negative emission generation (see next knowledge gap), in order to prioritise optimal exploitation from a systems perspective. In addition to factoring in regional biomass availability and the effects of behavioural changes in biomass use (e.g. reducing wood-fired space heating), optimising biomass use for seasonal purposes (including seasonal scheduling concepts) should be a key objective. To make such an analysis practically relevant, regulatory circumstances and social acceptance must be taken into account.

*ID: 13 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Economy, Regulations, Society, Energy Models | Based on: Multiple expert opinions (2) | Similar IDs: ID: 30 | Comments: The manure potential is being researched by the SWEET refuel.ch consortium.*

3.3.3. Combine energetic biomass usage and negative emission generation

The potential for using biomass to generate negative emissions should be further explored. This includes an analysis of the available options for different types of biomass and conversion technologies to extract carbon, taking into account factors such as plant sizes, regional biomass potential, costs, incentives, and the presence or absence of future CO_2 transport infrastructure. Estimates of the reduction in methane/hydrogen production due to negative emission generation should be made in relation to carbon and methane prices, as well as the potential prioritisation of negative emissions over methane/hydrogen production. Additionally, rules on the permanence of carbon capture must be revisited. In order to reduce costs, technologies for carbon capture, biochar and hydrochar production should be further developed.

Rationale: Biomass is one of the most cost-effective sources for negative carbon emissions in Switzerland. Therefore, it is necessary to clarify the following: how much negative emissions should be achieved through biomass in Switzerland? How can negative emissions be intelligently combined with energy use? To what extent both should be prioritised over each other? What technologies and infrastructure will be available and feasible? How should negative emissions be incentivised? And what regulations need to be created or adapted? While initial research on negative carbon emission technologies is available (Betz et al., 2023), the optimisation of CCS/CCU in combination with methane/hydrogen production, taking into account regional constraints such as biomass availability, infrastructure and the type of biomass conversion plants, as well as costs (energy and carbon prices, etc.) and social acceptance, is not yet available.

*ID: 14 | Timeframe: **2025-2035** | Significance: **High** | Uncertainty: **Low** | Topics: Economy, Regulations, TRL increase | Based on: Multiple expert opinions (3).*

3.4 Social acceptance

3.4.1. Assess social acceptance of seasonal storage technologies

Solidify knowledge of the social acceptance of seasonal storage technologies and related infrastructure. More specifically, identify the key issues that determine the social acceptance of specific storage projects and related energy infrastructure. Based on these findings, develop guidelines for utilities and project owners on the most appropriate and accepted storage technologies, as well as the optimal level of stakeholder involvement in the planning and operation of storage projects. One approach could be to identify ways in which the perceived disadvantages or social costs of a project, such as reduction in property value, loss of quality of life or loss of control over one's own heating system in favour of district heating, can be offset by benefits such as long-term cost reduction, increased resilience and increased independence. In terms of technology, ways should be explored to design infrastructure that is invisible or less obtrusive, or to repurpose/upgrade existing infrastructure, in order to foster acceptance.

Rationale: Social acceptance is a key factor in the success of a concrete project, so it is important to have a good understanding of the social acceptance mechanisms of seasonal storage technologies. Currently, there is limited research on this topic in Switzerland. While several studies have assessed hydro storage (e.g. (Tabi & Wüstenhagen, 2017), only initial Swiss-specific knowledge is available for STES (Sträter et al., 2025), and no knowledge exists yet on LRC storage and related infrastructure. Clear strategies, methods or guidelines on how to address or avoid social disapproval in projects could help project owners to implement them quickly and efficiently.

*ID: 15 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Society | Based on: Multiple expert opinions (3) | Comments: The social acceptance of STES is being researched by the SwissSTES flagship project.*

3.4.2. Include social acceptance in energy system models

Social acceptance of seasonal storage technologies and associated energy infrastructure should be incorporated into energy system models to provide a more realistic picture of future options/barriers for energy system development and seasonal storage integration. This is also a prerequisite for optimising such systems in terms of both cost and social acceptance.

Rationale: Social acceptance is not yet an integral part of energy system models. This means that the impact of social acceptance on future energy system scenarios, and in particular the feasibility of large-scale seasonal storage technologies and associated infrastructure, cannot be assessed or optimised.

*ID: 16 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low – Medium** | Topics: Energy Models, Society | Based on: Multiple expert opinions (2) | Similar IDs: ID: 6 | Comments: The UrbanTwin project is experimenting with integrating social acceptance into energy models, but only for urban areas and not nationwide. The project is funded by the ETH Board.*

3.5 Reserve market and resilience

3.5.1. Figure out ways to value resilience

Develop methods for valuing and enhancing system resilience and flexibility across multiple time scales — from short-term to seasonal — and across energy sectors such as electricity, gas, and heat. This includes designing and evaluating a dedicated reserve market that explicitly trades resilience services based on scarcity signals. The proposed market should be assessed against the existing reserve system[11] with respect to cost-effectiveness, potential for natural monopolies, and overall system resilience. Key research areas include defining market rules for fair access, service quality (e.g. supply duration guarantees), performance standards (e.g. response time, power output), and the structure and governance of an independent control body.

Rationale: In an increasingly decentralized and fluctuating energy system, compounded by geopolitical uncertainties, resilience and flexibility are gaining importance and may represent valuable market commodities. Seasonal storage could play a crucial role in providing such services. Current balancing markets, which operate on short time scales (seconds to minutes), are not suited to address seasonal flexibility needs. While emergency systems exist, their effectiveness and efficiency in a future, highly sector-coupled energy system — with diverse storage technologies — remain uncertain. Although concepts for long-term resilience markets in the electricity sector have been proposed (Perner & Janssen, 2017), it is still unclear how to design such instruments effectively for integrated systems that include thermal and chemical storage, as well as potential seasonal demand-side management.

*ID: 17 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low - Medium** | Topics: Economy, Regulations, Resilience | Based on: Multiple expert opinions (4) (Ganzer et al., 2022) | Similar IDs: ID: 1, ID: 29, ID: 33, ID: 37, ID: 41, ID: 44.*

3.5.2. Assess the impact of seasonal storage integration on system adequacy

Assess how different seasonal storage technologies and their combinations impact system adequacy, particularly under varying levels of energy imports and international market integration. This includes identifying which types and capacities of seasonal storage are most economically viable for enhancing resilience and reducing import risks.

Rationale: Seasonal storage technologies differ significantly in their technical and economic characteristics, which can strongly influence system adequacy and resilience. Current adequacy assessments focus solely on large-scale hydropower and are limited to the electricity sector (Weigt et al., 2022). A broader, cross-sectoral analysis is needed to guide optimal deployment and integration of diverse seasonal storage options.

*ID: 18 | Timeframe: **2025-2030** | Significance: **Medium - High** | Uncertainty: **Low - Medium** | Topics: Resilience | Based on: Single expert opinion | Similar IDs: ID: 17, ID: 20, ID: 27.*

3.6 EU electricity market and grid

3.6.1. Assess the role of seasonal storage without an EU-electricity agreement

Evaluate the short- and long-term implications of Switzerland not reaching an electricity agreement with the EU, focusing on the role of seasonal storage and sector coupling. This includes assessing how

[11] The reserve system is still being conceived; the winter reserve ordinance is limited in time till the end of 2026; the obligatory hydro reserve is already implemented in the Electricity Supply Act; rules for a thermal electricity reserve were recently approved.

different seasonal storage technologies (e.g. STES, LRC) can mitigate the impacts of limited electricity market access, and estimating the effects on the ability to import chemical energy carriers, such as hydrogen and biomethane.

Rationale: The consequences of Switzerland not being integrated into the EU electricity market for the role of seasonal storage (including STES and LRC) in mitigating negative effects are not well understood. To date, studies on this topic have only considered seasonal hydro storage (Frontier Economics, 2021; Weigt et al., 2022). Moreover, the impact of Switzerland's exclusion from the EU electricity market on its integration into future hydrogen and biomethane markets remains unclear. A comprehensive analysis is needed to inform resilient energy planning in the face of geopolitical uncertainty.

*ID: 19 | Timeframe: **2025-2028** | Significance: **High** | Uncertainty: **Medium** | Topics: Regulations, Resilience | Based on: Single expert opinion.*

3.6.2. Monitoring transition progress in Europe

Assess the development of the European electricity grid, generation capacity and demand in terms of import opportunities and the role of the Swiss grid for electricity transit. Estimate the impact of a delay to the planned expansion of European grid capacity, generation capacity and demand on import opportunities and electricity transit. Also estimate the lead time for implementing countermeasures in Switzerland (e.g. thermal backup plants, Swiss grid reinforcement) if delays to expansion or changes in demand become more serious and/or more transit capacity is required. Assess what type and what capacity of storage would be best suited to cope with these technical limitations on import possibilities. This assessment should also be extended to the development of the gas, hydrogen, and CO_2 demand, infrastructure, and production.

Rationale: The expansion of the European grid and generation capacity, as well as demand development, are crucial for the feasibility of importing wind power into Switzerland and for electricity transit. Therefore, it is important to have a good understanding of the development dynamics, which are subject to a number of uncertainties. Identifying and monitoring key parameters and their impact on import opportunities would allow for the early implementation of countermeasures, for which seasonal storage could be a valuable asset.

*ID: 20 | Timeframe: **2025-2035** | Significance: **Medium** | Uncertainty: **Low - Medium** | Topics: Resilience | Based on: Multiple expert opinions (4), (Weigt et al., 2022) | Similar IDs: ID: 27, ID: 31, ID: 32.*

3.7 Hydro power

3.7.1. Improve sediment management

Better ways of managing sediments in reservoir lakes need to be explored. These include methods to slow or prevent sedimentation in reservoirs, efficient sediment removal techniques, and ways to allow reservoirs to be emptied more deeply without severely compromising component life due to increased wear from suspended sediment.

Rationale: Due to glacier/permafrost melting leaving lots of loose debris masses and due to more frequent heavy runoff events, sediment inflow into reservoirs is increasing, so new ways must be found to avoid severe reductions in storage capacity and increased wear of technical equipment. While there are ideas/concepts available (see e.g. HydroSediNET), a comprehensive assessment of this issue is pending, which would be necessary for a widespread and tailored uptake of countermeasures.

*ID: 21 | Timeframe: **2025-2035** | Significance: **High** | Uncertainty: **Low** | Topics: TRL increase | Based on: Multiple expert opinions (2), (Boes et al., 2021) | Comments: Researched within the HydroSediNET network, sponsored by the Energy Sector Management Assistance Program (ESMAP).*

3.7.2. Understand and optimize the economic performance of hydro power

Assess the future role of storage and pumped-storage hydropower in national and international electricity markets, focusing on their participation in emerging short- and long-term reserve markets, opportunity costs relative to competing flexibility options (e.g. grid-connected batteries, backup plants), and their contribution to cross-border balancing and grid stability — particularly during stress events such as *Dunkelflaute* under varying EU market integration scenarios. Additionally, evaluate the economic impact of persistently low or negative electricity prices in summer, especially in combination with ecological flow requirements, and examine financial risks and mitigation strategies in the absence of an EU electricity agreement. Investigate cost-effective incentives for maintaining high water levels in reservoirs for spring resilience and assess the impact of different operational strategies on the lifetime of infrastructure (e.g. due to increased cycling or sedimentation-related wear).

Rationale: With long investment horizons, (pumped) storage hydropower faces considerable uncertainty regarding future market conditions, revenue streams, and regulatory frameworks. Improved understanding of market integration, operating strategies, and economic viability is essential to reduce investment risks and guide long-term planning and adaptation.

*ID: 22 | Timeframe: **2025-2035** | Significance: **High** | Uncertainty: **Low – Medium** | Topics: Economy, Resilience, TRL increase | Based on: Multiple expert opinions (3), (Barry et al., 2019) | Similar IDs: ID: 1, ID: 17, ID: 19, ID: 20, ID: 28.*

3.7.3. Optimize seasonal energy storage in multi-purpose dams

Investigate strategies for optimising reservoir storage capacity for multiple uses — such as electricity generation, flood control, and summer water supply for drinking and irrigation — while assessing the impacts of residual flow regulations on storage availability and operational flexibility. Explore options for expanding storage capacity, including dam heightening and the use of glacial lakes, and evaluate their technical feasibility, environmental trade-offs, and social acceptance in the context of multipurpose hydropower infrastructure.

Rationale: The interactions between residual flow requirements, multipurpose reservoir use, and seasonal storage capacity, particularly for winter electricity generation, remain poorly understood. Decisions on expanding or adapting reservoir infrastructure must consider evolving climate patterns, ecological impacts, dynamic electricity pricing, and the strategic role of storage for resilience and energy independence. A holistic understanding of these factors, supported by transparent communication, is essential to inform policy and foster public acceptance.

*ID: 23 | Timeframe: **2025-2035** | Significance: **Medium – High** | Uncertainty: **Low – Medium** | Topics: Economy, Regulations | Based on: Multiple expert opinions (3), (Boes et al., 2021), (Piot, 2020).*

3.7.4. Operation strategies and structural measures due to climate warming

Evaluate how projected impacts of global warming, such as increased summer evaporation, altered precipitation patterns, interannual effects (wet/dry years), reduced glacier meltwater, and extreme inflow events, should be integrated into the operational planning and infrastructure design of hydropower reservoirs. This includes assessing the need for structural adaptations, such as advanced spillway systems to safely raise fill levels and improved sediment management installations.

Rationale: While climate impacts on hydrology are increasingly well understood (e.g. Müller-Ferch et al., 2019), their systematic integration into reservoir operations and infrastructure planning remains limited. Existing strategies must be updated based on the latest climate scenarios (e.g. the upcoming CH2025 scenarios) to enhance climate resilience, reduce risk, and ensure sustainable hydropower performance across Switzerland.

*ID: 24 | Timeframe: **2030-2040** | Significance: **Medium – High** | Uncertainty: **Medium** | Topics: Economy, TRL increase (of new concepts) | Based on: Multiple expert opinions (2), (Zeyringer et al., 2018), (Boes et al., 2021) | Similar IDs: ID: 37.*

3.8 Swiss methane & hydrogen infrastructure

3.8.1. Understand and optimize transition of the gas network

Assess how the existing gas transport infrastructure will develop in future. This involves evaluating the size and location of current and future demand (e.g. new backup power stations), new production centres (e.g. biomethane plants) and potential storage facilities. It also involves an evaluation of the impact that new supply and demand patterns could have on the operation, management and financing of the transport infrastructure. Consideration should also be given to extending gas transport infrastructure to rural areas to improve biomethane collection and establishing clusters of smaller biogas conversion plants.

Rationale: With the phase-out of fossil natural gas and the switch to heat pumps for space heating, major changes to the gas transport network can be expected (BFE, 2019). An early understanding of the future gas infrastructure is helpful for coordinated and strategic planning, particularly with regard to the placement of backup generators and large gas storage facilities. Due to the dispersed nature of biomass accumulation, extending the gas transport infrastructure to rural areas could increase the amount of renewable gas available to the grid.

*ID: 25 | Timeframe: **2030-2035** | Significance: **High** | Uncertainty: **Medium** | Topics: Economy | Based on: Own deduction | Similar IDs: ID: 13, ID: 15, ID: 26, ID: 32 | Comments: This topic is being addressed in the 'Netztransformationsplan erneuerbare Gase' initiative (NeG-Initiative) of the Swiss gas network providers.*

3.8.2. Understand the future hydrogen landscape in Switzerland

Assess the hydrogen demand and potential form of hydrogen transport infrastructure in Switzerland (beyond the Transitgas pipeline) and the associated costs. This includes assessing the future demand (spatially and temporally resolved), clarifying the coexistence with the existing methane network and a future CO_2 network (which demand can be met by hydrogen? Which methane infrastructure can be converted? Where are both infrastructures needed in parallel? What is the potential for interaction?). It would also be interesting to assess whether, how and where seasonal storage for hydrogen buffering could be integrated. A regulatory basis for a novel hydrogen transport infrastructure is also needed.

Rationale: If Switzerland is connected to the EHB and hydrogen is available at attractive prices compared to carbon-neutral methane, a novel transport infrastructure will be required alongside the existing methane infrastructure, for which many open questions of a technical, regulatory and social nature remain to be answered. Most importantly, the demand is still very unclear and should be assessed (spatially and temporally resolved). This is a prerequisite for assessing the potential integration of large-scale hydrogen storage.

*ID: 26 | Timeframe: **2030-2035** | Significance: **Medium – High** | Uncertainty: **Medium – High** | Topics: Economy, Regulations, System Model | Based on: Multiple expert opinions (3), (Der Bundesrat, 2024) | Similar IDs: ID: 19, ID: 20, ID: 31, ID: 39 | Comments: This topic is being addressed in the 'Netztransformationsplan erneuerbare Gase' initiative (NeG-Initiative) of the Swiss gas network providers.*

3.9 Seasonal storage system integration

3.9.1. Understand interaction of seasonal storage with the energy system

Investigate how various seasonal storage technologies can be optimally integrated into a sector-coupled energy system by analysing their interactions with short-term storage, energy transport infrastructure, and sector coupling technologies. This requires system-level modelling that incorporates all relevant storage types (e.g. STES variants, large dam hydro, LRCs, biomass) while accounting for spatial constraints, geological conditions, infrastructure availability, and the dynamic operational characteristics of each technology (e.g. response time, charging/discharging rates). Findings should be validated through large-scale pilot projects to assess real-world integration and demonstrate the benefits to investors and policymakers.

Rationale: Although the technical properties of seasonal storage options are well documented, their roles and interactions within an integrated, sector-coupled energy system remain poorly understood. Current models rarely assess all storage types simultaneously or consider key constraints such as site-specific infrastructure, land use, or subsurface conditions. A comprehensive system perspective is essential to determine optimal siting, required capacities, and operational strategies, and to inform investment and policy decisions for a resilient energy planning.

*ID: 27 | Timeframe: **2025-2030** | Significance: **High** | Uncertainty: **Low** | Topics: Energy Models, Pilots, Economy | Based on: Multiple expert opinions (8), (Friedl et al., 2018), (Forum Energiespeicher Schweiz, 2024) | Similar IDs: ID: 6 , ID: 18, ID: 35 | Comments: The interaction between short- and long-term storage is being researched in the STORE Innosuisse flagship.*

3.9.2. Find the best way to deal with summer electricity

Determine the best way to deal with the overall surplus of electricity during the summer months. This would involve calculating the LCOS and considering the operational dynamics in the short and long term (e.g. reaction time and charge/discharge speeds) as well as the knock-on effects and co-benefits (e.g. reduction in grid congestion and PV curtailment) for all storage options under the same assumptions/boundary conditions.

Rationale: Even after short-term balancing by flexible demand and short-term storage, it is foreseeable that there will be surplus electricity in summer. As export possibilities appear limited, a solution must be found for this energy, taking into account winter energy shortages, infrastructure costs, and resilience. Although some curtailment is foreseeable, it is unclear which fraction should be stored, how it should be stored, and what the cost implications are. No studies simultaneously consider all long-term options for using surplus electricity (after day/night balancing with short-term storage) in detail, such as different types of STES and Power-to-X paths, including hydrogen production and biomass upgrading. A comprehensive analysis would need to consider the additional benefits and limitations of the options in terms of their short-term dynamics and the possibilities for coupling with short-term storage.

*ID: 28 | Timeframe: **2025-2030** | Significance: **Medium - high** | Uncertainty: **Medium** | Topics: Economy, Energy Models | Based on: Own deduction | Similar IDs: ID: 6, ID: 10.*

3.9.3. Find and monetize additional system benefits of seasonal storage

Beyond the traditional role of purchasing, storing, and selling energy on a seasonal basis, additional revenue streams for seasonal storage should be explored. These include using storage for short- to medium-term energy balancing, such as stabilizing the gas grid, relieving electricity grid congestion or curtailment, and shaving peak loads in district heating systems, which would increase the number of operational cycles and potentially improve economic performance. Participating in future reserve markets is another option, where storing energy to support system resilience could generate income. To fully assess these opportunities, the technical, economic, and operational implications must be examined. This includes evaluating increased wear from more frequent cycling, changes in system lifetime and costs, and potential trade-offs or synergies between fast-response operation and reserve capacity provision.

Rationale: Seasonal storage typically experiences low annual utilization, which limits its profitability when used solely for seasonal energy shifting. Leveraging the same infrastructure for additional services may significantly improve cost-effectiveness, but there is currently limited understanding of the technical and non-technical benefits that such multi-service operation could deliver. It remains unclear how these benefits could be monetized and what technological modifications might be required to support such flexibility. Addressing this gap is essential to unlock the full value of seasonal storage in the future energy system.

*ID: 29 | Timeframe: **2025-2030** | Significance: **Medium** | Uncertainty: **Medium** | Topics: Economy | Based on: Own deduction | Similar IDs: ID: 17 | Comments: The STORE Innosuisse flagship project considers the dynamic interplay between short- and long-term storage.*

3.10 Exergy efficiency and local resources

3.10.1. Incentivise or enforce exergetically efficient use of local resources

Develop regulations and/or incentives regarding exergy efficiency, regionality and seasonal patterns of the energy supply-demand pathway to achieve higher energy system efficiency. This includes incentivising the use of chemical energy carriers in applications that make the best use of high exergy, such as high-temperature process heat and CHP plants as well as saving easily storable energy carriers, such as wood, for the winter months. It also involves incentivising heat production using locally available resources and combining this with STES where appropriate.

Rationale: Currently, the exergy content of energy sources is often not used optimally, particularly for space heating. Additionally, available energy sources are frequently not optimised with regard to their seasonal characteristics (e.g. ease of storage) and regional availability. Incentives and/or regulations are needed to ensure these aspects are considered.

*ID: 30 | Timeframe: **2025-2030** | Significance: **Medium - High** | Uncertainty: **Low - Medium** | Topics: Economy, Regulations, Society | Based on: Multiple expert opinions (2), (Vuille et al., 2023) | Similar IDs: ID: 35, ID: 36.*

3.11 Hydrogen & methane imports

3.11.1. Prepare for a hydrogen infrastructure

To successfully connect to the EHB, several things need to be done and/or clarified. Swiss hydrogen regulations must be developed and aligned with European regulations. An agreement on participation in the EU hydrogen market must be reached. The future import price must be assessed to provide a reliable time-dependent (seasonal) cost of hydrogen, together with domestic infrastructure costs. This is crucial for investment decisions regarding hydrogen demand technologies and large-scale storage, as well as for comparisons with local production costs. Additionally, given Europe's ambitious expansion plans, the impact of delays in backbone construction and hydrogen production abroad should be considered, as well as the lead time required to make a decision.

Rationale: Experts agree that connecting to the EHB would be advantageous for Switzerland, as import prices for larger volumes appear to be competitive with, or even lower than, domestic production. However, there are currently no formal agreements in place with neighbouring countries, and Switzerland does not yet have a regulatory framework that is aligned with those of its neighbours. To create business cases and incentives for investment, the costs of hydrogen must become clearer and more reliable, including import costs as well as domestic distribution costs. Large-scale hydrogen storage would be incentivised by significant variations in import prices, so estimates of these variations need to be quantified. Investment risk is closely related to the likelihood of delays in constructing the hydrogen backbone and production facilities abroad. Close monitoring of progress and potential obstacles could therefore reduce these risks. Finally, a clear and reliable decarbonisation path is a prerequisite for a potential hydrogen market/import, but this is currently insufficiently implemented in Switzerland to reduce investment risks and enable business development (Wenger et al., 2022).

*ID: 31 | Timeframe: **2025-2035** | Significance: **Medium – High** | Uncertainty: **Medium** | Topics: Economy, Regulations, Resilience | Based on: Multiple expert opinions (3) | Similar IDs: ID: 20, ID: 26, ID: 33, ID: 39 | Comments: The Gas Supply Act is currently being developed, likely containing also regulations regarding hydrogen.*

3.11.2. Maintain possibility to import renewable methane

The possibility of importing methane should be maintained and the future potential and import price variability of bio- and e-methane should be estimated. For comparison with domestic storage, the contractual and technical details of securing gas storage abroad should be assessed. Regulations are also required for the grid-bound import recognition of carbon neutral methane.

Rationale: As methane imports remain important in the energy system, reliable access to international markets remains relevant and efforts and strategies to decarbonise imported methane are needed. There is also uncertainty about the availability, price and price volatility of imported carbon-neutral methane, which is an important consideration for the deployment of large-scale domestic gas storage. In addition, grid-bound (virtual) carbon-neutral methane imports are not yet exempt from the CO_2 levy because there is no international clearing system for proof of origin, which would be a prerequisite for inclusion in the CO_2 Act and the Mineral Oil Tax Act (MinöStG).

*ID: 32 | Timeframe: **2025-2035** | Significance: **Medium – High** | Uncertainty: **Medium** | Topics: Economy, Regulations, Resilience | Based on: Own deduction | Similar IDs: ID: 25 | Comments: Regarding certificates of grid-bound imports of renewable gases see Motion 21.4318.*

3.12 Lined rock cavern operation

3.12.1. Investment uncertainty and business cases for LRC

Open questions regarding incentives and business cases should be addressed. This includes assessing the future volatility of import prices for methane (and potentially hydrogen), exploring the options for participating in future short- and long-term reserve markets, and understanding the possible roles and benefits of short- and long-term buffering/grid stabilisation of gas supply and demand. Clarity is also needed on construction and operating costs. Additionally, legal barriers to construction and operation need to be identified, and any missing regulatory constraints should be addressed. Finally, clear information should be compiled on the options for securing capacity abroad, including the associated costs, speed of access and reliability.

Rationale: The necessary information to calculate a reliable future LCOS — required for a business case for LRC — is not yet available. This includes future gas import price fluctuations, as well as other revenue streams, such as participation in reserve markets, and construction and operating costs. There are also uncertainties regarding legal barriers and the need for new rules to ensure fair and system-friendly market integration with well-defined quality of service standards. The planned LRC in Oberwallis is likely to address questions relating to technical construction details, regulatory aspects, and economic performance under current market schemes. In order to inform the discussion on LRC versus securing capacity abroad, more reliable information on both options is needed.

*ID: 33 | Timeframe: **2030-2040** | Significance: **Medium – High** | Uncertainty: **Medium** | Topics: Economy, Regulations, Resilience | Based on: Single expert opinion | Similar IDs: ID: 2, ID: 17, ID: 20, ID: 27, ID: 32, ID: 39, ID: 41 | Comments: The LCOS estimation of 15 CHF/MWh for methane LRC is based on price volatilities from years 2013 – 2020 and 1.5 cycles/year projected into the future, which is a strong assumption, given that demand is likely to change in the coming years (Kober et al., 2024).*

3.12.2. Consolidate geological information for suitable gas storage

There is a need for more consolidated information on suitable geological formations for LRC, but also potentially other storage technologies (such as porous rock and salt caverns).

Rationale: If additional gas storage facilities are required beyond the planned facility in Oberwallis, potential sites near major pipelines, gas hubs and major demand centres should be investigated for geological suitability. This would involve identifying sites for additional LRCs and exploring the possibility of implementing salt or porous rock storage.

*ID: 34 | Timeframe: **2025-2035** | Significance: **Medium** | Uncertainty: **Medium** | Topics: Economy | Based on: Multiple expert opinions (2), (Hälfiger, 2024) | Similar IDs: ID: 8 | Comments: The Federal Council was assigned to develop a program for nation-wide exploration of the subsurface (Motion 20.4063).*

3.13 Seasonal scheduling

3.13.1. Estimate the impact of systematic seasonal scheduling with system models

Integrate seasonal scheduling options into energy system models, such as dual-fired district heating networks (heat pump with CHP/boiler), with or without STES and biomass upgrading (e.g. hydrogen injection in gasification processes). Take into account regional and local constraints in terms of available energy infrastructure, geographical and geological suitability, and social acceptance, in order to assess if and how they can be deployed optimally.

Rationale: The potential impact of seasonal scheduling on different technologies, the energy system, and the seasonal supply-demand mismatch is not well understood. To assess potential beneficial (and detrimental) technology combinations, optimal schedules, and their impact on system costs and efficiency, detailed modelling of the seasonal scheduling of sector coupling and seasonal storage technologies in energy system models would be required.

*ID: 35 | Timeframe: **2025-2030** | Significance: **Medium – High** | Uncertainty: **Medium** | Topics: Energy Models | Based on: Single expert opinion | Similar IDs: ID: 27, ID: 30, ID: 40.*

3.13.2. Find incentives and overcome barriers for seasonal scheduling processes

The benefits and challenges of implementing and optimising seasonal scheduling should be explored further. This should include exploring which processes should be seasonally coupled (e.g. through energy system models — see the previous knowledge gap), how the energy market could be changed to incentivise such operations and which business cases might be attractive. A potential combination of seasonal scheduling technologies should, of course, be tested in a pilot project to fine-tune details such as control and operation strategies and to identify regulatory hurdles. This would also increase visibility to investors by presenting potential business cases.

Rationale: Seasonal scheduling could combine different storage options and sector coupling technologies more effectively, playing to their strengths and increasing the flexibility and robustness of the energy system while reducing costs. However, these concepts have not yet been thoroughly or systematically investigated, meaning there is currently no comprehensive overview of the available options, their respective advantages and disadvantages, and their economic viability.

*ID: 36 | Timeframe: **2025-2035** | Significance: **Medium – High** | Uncertainty: **Medium** | Topics: Economy, Regulations, Pilots | Based on: Multiple expert opinions (3) | Similar IDs: ID: 27.*

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5 Appendix

5.1 Further knowledge gaps

Knowledge gaps with lower significance and higher uncertainty are listed here.

5.1.1. Estimate interannual weather variability and work out how to deal with it

The implications of interannual weather variability need to be better assessed to understand the possible impacts, particularly with regard to inflow storage (e.g. hydropower and biomass), and thus to resilience. Based on the results, the reserve market/scheme should be equipped with the appropriate tools to address interannual effects.[12]

Rationale: Current Swiss energy system models only look at annual time scales and are not able to capture interannual effects that may become more relevant due to global warming (droughts, etc.).

*ID: 37 | Timeframe: **2030-2035** | Significance: **Medium** | Uncertainty: **Medium** | Topics: Economy, Resilience, Environment | Based on: (Ganzer et al., 2022; Zeyringer et al., 2018).*

5.1.2. Assess the sustainability of seasonal storage

A systematic assessment of the sustainability of seasonal storage options and related infrastructure is needed. This should include life cycle assessments of all options, as well as considerations of the circular economy and social impacts, both nationally and internationally.

Rationale: In order to easily compare the different storage options and their associated infrastructure in terms of sustainability, a systematic assessment of their environmental and social impacts throughout their life cycles, at both the national and international levels, would be required. Such an assessment is currently lacking. Information on these aspects is scattered and only available on a technology-by-technology basis (e.g. for some STES technologies (Hayatina et al., 2023) and hydropower (Flury & Frischknecht, 2012). This makes it difficult to consider and compare the options. Although there are energy system models with life cycle assessment (LCA) integration (Schnidrig, Brun, et al., 2023), comparisons are limited since not all seasonal storage options are represented in the model. While there are studies that consider the spill-over effects of the energy transition in Switzerland (Hahn Menacho et al., 2025), specific information on seasonal storage technologies is lacking. More practical information on how to improve these aspects is also needed, e.g. technology-specific approaches to the circular economy, impact mitigation, and procedures to ensure social equity.

*ID: 38 | Timeframe: **2025-2040** | Significance: **Low - Medium** | Uncertainty: **Medium** | Topics: Economy, Society, Environment | Based on: Own deduction.*

5.1.3. How to build or convert LRCs for hydrogen storage

The suitability of LRC storage for hydrogen should be assessed. This should include research into how methane LRCs can be made hydrogen-ready, as well as planning for the transition phase and estimating the routing of hydrogen pipelines for the strategic siting of LRCs. The LCOS of hydrogen storage is unclear and needs to be clarified. This should include estimating price fluctuations of hydrogen imports and the costs of domestic production, domestic demand and construction and operation costs of hydrogen LRCs. Regulations for hydrogen storage and market participation should also be developed.

Rationale: Currently, there is no experience of converting LRCs from methane to hydrogen, and only one small hydrogen LRC pilot plant (Johansson et al., 2018). Consequently, there is a lack of knowledge regarding LRC conversion, LCOS and options for market participation, which makes it difficult to develop business cases. Additionally, there is no regulatory basis for hydrogen LRCs.

[12] Art 8b Ziff 7 Abs a StromVG allows the Federal Council to constitute an electricity reserve for longer than one year. The details are not yet conceived.

*ID: 39 | Timeframe: **2030-2040** | Significance: **Medium** | Uncertainty: **Medium – High** | Topics: TRL increase, Economy, Regulations | Based on: Multiple expert opinions (2) | Similar IDs: ID: 26, ID: 31, ID: 33 | Comments: The creation of a round table on gas storage is suggested in the Hydrogen Strategy (Der Bundesrat, 2024).*

5.1.4. Explore the potential of seasonal demand side management

In the context of the seasonal scheduling of processes, it is important to gain a better understanding of the impact and potential of seasonal demand-side management on the energy system, and of its relationship with seasonal variations in dynamic energy prices.

Rationale: When the seasonal difference in energy prices reaches a certain level, it is conceivable that companies will start planning their production seasonally in order to be more cost-efficient. However, it is unclear at what price difference companies/processes begin to manage demand, or what effect this has on the energy system relative to the magnitude of the energy price variation.

*ID: 40 | Timeframe: **2030-2035** | Significance: **Medium** | Uncertainty: **Medium** | Topics: Economy | Based on: Own deduction.*

5.1.5. Find rules for a system friendly and fair storage ownership

Rules on the ownership of large seasonal storage facilities should be developed, and the possibility of central coordination of storage owners should be explored.

Rationale: The question of which ownership model would allow for fair access and better coordination of investments in shared infrastructure to avoid monopolies, the abuse of market power and ensure competition remains unanswered. There is also a need for debate on whether a central coordination entity is required to coordinate storage efficiently on a national scale (similar to Swissgrid), to maximise system friendliness and guarantee a certain level of resilience — either as an alternative to, or in addition to, a reserve market.

*ID: 41 | Timeframe: **2025-2035** | Significance: **Medium** | Uncertainty: **Medium** | Topics: Economy, Regulations | Based on: Multiple expert opinions (2) | Similar IDs: ID: 1, ID: 33.*

5.1.6. Further develop and test hydrothermal biomass gasification

Further develop hydrothermal gasification technology. In particular, costs for smaller plants should be reduced as far as possible. Simple ways of incorporating hydrogen to increase methane yields, as well as ways of generating negative carbon emissions (e.g. biochar), should be explored. These developments should be combined in a commercial-scale pilot plant to test operation under real conditions and demonstrate the technology to investors.

Rationale: Hydrothermal gasification is more efficient than anaerobic digestion but less mature. To replace the predominantly small-scale anaerobic digestion plants in Switzerland, cost-effective small units are essential for wider adoption. For seasonal operation (see Chapter 2.2.3), hydrogen injection to boost methane yield and carbon separation methods for negative emissions should be tested in a commercial-scale pilot to achieve greater visibility among potential investors. The largest currently existing facility in Switzerland is HydroPilot at Paul-Scherrer-Institute (PSI) with a TRL of 6.

*ID: 42 | Timeframe: **2025-2035** | Significance: **Medium** | Uncertainty: **Medium** | Topics: TRL increase, Pilots | Based on: Own deduction | Similar IDs: ID: 13, ID: 14, ID: 36.*

5.1.7. Develop liquid fuel production technologies suitable for Switzerland

Increase efficiency, reduce costs and explore valuable by-products of liquid fuel synthesis. This includes optimising the conversion of biomass to methanol, achieving high efficiency at a smaller scale with low investment costs. The production of heavier hydrocarbons (e.g. kerosene) from methanol and/or FT synthesis should also be developed further to increase efficiency and reduce costs for small-scale units. Additionally, the potential for using side streams (e.g. from a bio-crude oil refinery) to produce valuable chemicals for the chemical industry, should be explored.

Rationale: For reasons of resilience (e.g. military, emergency services, backup generators), some local production of liquid fuels may be important, even if prices are not competitive with imports. Although suitable production processes exist, they are usually not very advanced and/or require large-scale production to achieve reasonable efficiency and cost, which makes them unsuitable for smaller-scale production in Switzerland. The main limiting factors (aside from general price competitiveness) are the limited availability of biomass at potential plants for biomass liquefaction, which restricts plant size, and/or the relatively high cost of the large quantities of hydrogen required for e-fuels. Increasing the value generation of such processes by producing additional valuable outputs for the chemical industry (which might also be necessary for reasons of resilience) could make such processes more economically viable.

*ID: 43 | Timeframe: **2030-2040** | Significance: **Medium** | Uncertainty: **Medium - High** | Topics: TRL increase, Economy | Based on: Multiple expert opinions (2) | Comments: Liquid fuel production is researched by the SWEET refuel.ch consortium.*

5.1.8. Understand role of liquid fuels

Understand the future role of carbon-neutral liquid fuels by identifying priority applications, determining the required fuel types (e.g. methanol, diesel, kerosene), and optimising their integration into the carbon ecosystem. Business cases to enhance resilience may involve both imported and domestic fuels. A thorough understanding of costs, including production, transport, and storage, and technical aspects (e.g. where simpler-to-produce methanol could substitute diesel or kerosene) is essential for comparing them to methane or hydrogen for similar uses. Given the need to import SAFs at scale, additional uses to enhance system resilience should also be considered.

Rationale: Despite potentially higher costs, especially compared to methane or hydrogen, carbon-neutral liquid fuels may play a valuable role in the future energy system due to their simple and cost-effective long-term storage. Their system-level benefits and potential import prices must therefore be carefully assessed and compared to those of methane/hydrogen. Given their easy storability, stockpiling SAFs could offer strategic value, enabling their use in emergencies, such as for electricity or heat generation, and should be considered to enhance overall system resilience.

*ID: 44 | Timeframe: **2030-2040** | Significance: **Low - Medium** | Uncertainty: **Medium - High** | Topics: Economy | Based on: Single expert opinion | Comments: Liquid fuels are researched by the SWEET refuel.ch consortium.*

5.1.9. Further investigate metal fuels

Further investigate the potential of metal fuels for seasonal storage. This includes developing a better understanding of the technical details, costs, efficiencies, and potential applications (e.g. heat and electricity generation). Promising concepts should be tested on a larger scale in pilot plants to assess operational stability and cycle stability, as well as potential technical, economic and regulatory barriers.

Rationale: Metal fuels are still at an early stage of research, and their potential for seasonal energy storage and integration into the energy system remains largely unexplored. While several promising concepts are under investigation, it is currently uncertain whether and under what conditions metal fuels could become viable, widely adopted seasonal energy carriers. They offer notable advantages — such as the absence of carbon emissions, non-toxicity, non-flammability, and relatively high energy density (e.g. compared to sensible thermal energy storage). However, key parameters such as cost, conversion efficiency, and cycle stability are not yet well understood and require further research.

*ID: 45 | Timeframe: **2025-2030** | Significance: **Medium** | Uncertainty: **High** | Topics: TRL increase Economy, Regulations, Pilots | Based on: Single expert opinion.*

5.1.10. Continuously monitor development in waste availability and treatment

Explore ways to seasonally store waste easier and cheaper. This involves further exploring methods of separating waste fractions that can be stored from mixed waste, and identify which storable waste types could be burned in simpler, lower-cost furnaces without requiring advanced flue gas treatment. Compare the potential of seasonally optimising waste incinerator operation with the flexibility gained through STES and assess the synergies of combining both approaches. Estimate future trends in waste quantity and calorific value and develop strategies to avoid infrastructure lock-in due to declining waste volumes.

Rationale: In Switzerland, the seasonal flexibility of waste incineration remains underexplored. While studies have analysed operational flexibility and seasonal storage of some waste (Dettli et al., 2014;

Fuhrer et al., 2025), they have not examined integration with STES. Combining seasonal flexibility of incineration operation with STES could leverage synergies to further increase seasonal flexibility. A challenge is the lack of cost-effective methods to separate storable waste fractions from mixed municipal and industrial waste. In particular, isolating clean-burning fractions that do not require costly flue gas treatment could enable their use in simple, low-CAPEX furnaces. This would help providing peak thermal loads without the need to oversize incineration capacity. While projections of municipal waste volumes are available (Birnstengel et al., 2018), there is uncertainty around future waste composition and availability, especially in light of evolving circular economy policies. Continuous monitoring of these developments is essential, as waste incinerators are often embedded in long-lived infrastructure such as high-temperature district heating networks (>100 °C). A decline in waste availability could make it difficult to transition to lower-temperature alternatives like heat pumps, thereby increasing the risk of long-term technological lock-in.

*ID: 46 | Timeframe: **2025-2040** | Significance: **Low - Medium** | Uncertainty: **High** | Topics: Economy | Based on: Single expert opinion.*

5.2 Back-of-the-envelope calculations on biomass usage

5.2.1. Assumptions

The assumptions made are highly simplified and should only provide a rough estimate of the order of magnitude of the potential. These assumptions are briefly explained below:

Biomass potentials: The biomass assumptions are taken from Thees et al. 2017 and are expressed in TWh_{LHV} of the respective raw biomass. In this estimate we distinguish between *manure* (7.4 TWh_{raw}), *woody biomass* (14 TWh_{raw}) and *other biomass* (green waste, sewage sludge etc., 4.5 TWh_{raw}). This calculation only takes into account the sustainable potential. Given the dispersed nature of manure and the challenges associated with its use, only 80 % of the estimated total sustainable potential is considered available for exploration. A slightly higher figure of 90 % is used of the woody biomass fraction and other biomass, as they are either more transportable or ‘occur’ more centrally. Much of the biomass is already tied to uses and it is not clear how much of these fractions can be made available for (seasonal) energy services. For the sake of simplicity, the total sustainable potential is considered and made somewhat more realistic by slightly reducing the utilisation rates. Nevertheless, the selected utilisation rate is probably still too high. However, it should provide an indication of the potential for development if the use of biomass energy is prioritised.

Available processes: We consider 4 different processes for direct biomass processing: anaerobic digestion (mature) and hydrothermal gasification of wet biomass, gasification and direct combustion of woody biomass. Due to the technological simplicity of anaerobic digestion and the resulting likelihood of its use in more remote locations and on a smaller scale, 80 % of *manure* (often in remote locations with small plants) and 30 % of *other biomass* fractions (often closer to urban centres with larger plants) are processed by this technology. Conversely, hydrothermal gasification processes 20 % of *manure* and 70 % of *other biomass*. Of the woody biomass, 70 % is gasified and 30 % is burned directly for heat generation. As wood is easier to transport, larger gasification plants can be built and are also more likely to be connected to a methane pipeline.

Storage and seasonality: All biomass processing plants operate continuously throughout the year to maximise capacity factor. The wet biomass fraction, in particular, cannot be stored for long periods and must be processed continuously anyway. It is estimated that 1.5 TWh_{LHV} of seasonal methane storage is available, and that wood can also be stored seasonally. The year is divided into two seasons: summer and winter, each lasting six months.

Gas network connections: To estimate the potential methane production, it is important to note that only part of the biomass treatment plants can be connected to the gas grid. To take this into account, only 50 % of decentralised manure digesters are considered to be connected to a gas grid, whereas 90 % of hydrothermal gasification plants and wood gasification plants are connected and 80 % of other wet biomass digesters (as they are more centralised). The unconnected digesters produce biogas continuously, which is burned in an engine to produce electricity and heat. While other transport possibilities exist (e.g. via road), they are more expensive as stated in Chapter 2.3.3 and might only become interesting at very high methane prices.

Efficiencies: Anaerobic digestion is estimated to be 30 % efficient, hydrothermal gasification 70 % and wood gasification 60 % ($LHV_{raw\ biomas} \rightarrow LHV_{CH4}$). Combustion of the gas in a gas turbine results in an electrical efficiency of around 35 %, with an additional 40 % of heat recovered for space heating. It is not assumed that large capacities of combined cycle gas turbines with higher efficiencies are installed. To estimate how much the use of waste heat reduces the electricity demand, the respective heat content is converted to an equivalent amount of electricity using a heat pump COP of 3.

Energy density, volume density and methane - carbon dioxide ratio: Anaerobic digestion is assumed to produce gases consisting of 60 % methane and 40 % CO_2 (Guidati et al. 2021), hydrothermal gasification 70 % methane and 30 % CO_2 (Muhlke et al. 2023) and wood gasification 60 % methane and 40 % CO_2.[13] Those ratios are highly dependent on the actual feedstock, but are typically roughly around those values. The volumetric density of CO_2 is 1.98 kg/m^3, energy density of methane is 13.9 kWh/kg (13.9×10^{-6} TWh/t), hydrogen 33.3 kWh/kg (33.3×10^{-6} TWh/t).

5.2.2. Estimating methane production

If biomass potential were prioritised for methane production to be fed into the gas network, the biomethane yield could be estimated as follows.

How to read the table: The tables are arranged by biomass fraction and should be read from left to right. The initial quantity of the respective raw biomass fraction is stated on the left. The greyed-out percentages show the proportion of energy transferred from one step to the next. The 'Exploration' column shows how much of the initial feedstock quantity is considered available for conversion. 'Process selection' divides or assigns the available fraction between the available processes. 'Conversion efficiency' explains how much of the raw biomass fraction inputted into the conversion process ends up in the end product. The 'Gas network connection' explains how much of the produced gas can be injected into the gas network. The 'Yield' describes the methane output available to the gas network.

<table>
<tr><th colspan="2">Feedstock and available processes</th><th>Exploration</th><th>Process selection</th><th>Conversion efficiency</th><th>Gas network connection</th><th>Yield</th></tr>
<tr><td rowspan="4">**Manure** 7.5 TWh_{raw}</td><td rowspan="2">Anaerobic digestion</td><td rowspan="2">80 %</td><td>80 %</td><td>30 %</td><td>50 %</td><td rowspan="2">0.72 TWh_{CH4}</td></tr>
<tr><td>4.8 TWh_{raw}</td><td>1.44 TWh_{CH4}</td><td>0.72 TWh_{CH4}</td></tr>
<tr><td rowspan="2">Hydrothermal gasification</td><td rowspan="2">6 TWh_{raw}</td><td>20 %</td><td>70 %</td><td>90 %</td><td rowspan="2">0.76 TWh_{CH4}</td></tr>
<tr><td>1.2 TWh_{raw}</td><td>0.84 TWh_{CH4}</td><td>0.76 TWh_{CH4}</td></tr>
<tr><td rowspan="2">**Wood** 14 TWh_{raw}</td><td rowspan="2">Gasification</td><td>90 %</td><td>70 %*</td><td>60 %</td><td>90 %</td><td rowspan="2">4.76 TWh_{CH4}</td></tr>
<tr><td>12.9 TWh_{raw}</td><td>8.82 TWh_{raw}</td><td>5.29 TWh_{CH4}</td><td>4.76 TWh_{CH4}</td></tr>
<tr><td rowspan="4">**Other biomass** 4.5 TWh_{raw}</td><td rowspan="2">Anaerobic digestion</td><td rowspan="2">90 %</td><td>30 %</td><td>30 %</td><td>80 %</td><td rowspan="2">0.29 TWh_{CH4}</td></tr>
<tr><td>1.22 TWh_{raw}</td><td>0.36 TWh_{CH4}</td><td>0.29 TWh_{CH4}</td></tr>
<tr><td rowspan="2">Hydrothermal gasification</td><td rowspan="2">4.05 TWh_{raw}</td><td>70 %</td><td>70 %</td><td>90 %</td><td rowspan="2">1.79 TWh_{CH4}</td></tr>
<tr><td>2.84 TWh_{raw}</td><td>1.99 TWh_{CH4}</td><td>1.79 TWh_{CH4}</td></tr>
</table>

*Not all wood is gasified.

[13] Specific information about the CH4:CO2 ratio of wood gasification with subsequent methanation without additional hydrogen injection is not straight forward to get (e.g. here with hydrogen injection: Bahč et al., 2024), also since usually not all carbon is gasified. The ratio is therefore assumed to be slightly lower than hydrothermal gasification at 3:2.

The estimated yearly methane production that could be fed into the gas grid is around 8.3 TWh$_{CH4}$ per year. However, this estimation is slightly optimistic and could be considerably lower if less wood is gasified and/or combusted directly at the facility rather than being injected into the gas grid

5.2.3. Estimating winter electricity production/savings

If the available biomass was prioritized for electricity production, the potential electricity production and electricity savings from waste heat integration could be estimated as follows.

<u>How to read the table:</u> In addition to the description given in Section 5.2.2, the ‘Winter fraction’ halves the available methane production, as it is assumed that conversion plants run continuously (except for direct combustion of wood). The second ‘Conversion efficiency’ explains how much electricity is produced in the gas-to-power-and-heat process and how much waste heat is available for heating purposes. The ‘Yield’ describes electricity production and the amount of electricity that could be saved by replacing electric heat pumps with waste heat (considering a COP of 3).

Feedstock and available processes		Exploration	Process selection	Conversion efficiency	Winter fraction	Conversion efficiency	Yield/Production
Manure 7.5 TWh$_{raw}$	Anaerobic digestion	80 %	80 %	30 %	50 %	35 % electricity	0.25 TWh$_{el}$
						0.25 TWh$_{el}$	
			4.8 TWh$_{raw}$	1.44 TWh$_{CH4}$	0.72 TWh$_{CH4}$	40 % heat	saves 0.1 TWh$_{el}$
						0.3 TWh$_{th}$	
	Hydrothermal gasification	6 TWh$_{raw}$	20 %	70 %	50 %	35 % electricity	0.15 TWh$_{el}$
						0.15 TWh$_{el}$	
			1.2 TWh$_{raw}$	0.84 TWh$_{CH4}$	0.42 TWh$_{CH4}$	40 % heat	saves 0.06 TWh$_{el}$
						0.17 TWh$_{th}$	
Wood 14 TWh$_{raw}$	Gasification	90 %	70 %	60 %	50 %	35 % electricity	0.95 TWh$_{el}$
						0.95 TWh$_{el}$	
			9.03 TWh$_{raw}$	5.42 TWh$_{CH4}$	2.7 TWh$_{CH4}$	40 % heat	saves 0.36 TWh$_{el}$
						1.1 TWh$_{th}$	
	Direct combustion	12.9 TWh$_{raw}$	30 %	95 %	100 %*	-	saves 1.23 TWh$_{el}$
			3.87 TWh$_{raw}$	3.68 TWh$_{th}$	3.68 TWh$_{th}$	-	
Other biomass 4.5 TWh$_{raw}$	Anaerobic digestion	90 %	30 %	30 %	50 %	35 % electricity	0.06 TWh$_{el}$
						0.06 TWh$_{el}$	
			1.22 TWh$_{raw}$	0.36 TWh$_{CH4}$	0.18 TWh$_{CH4}$	40 % heat	saves 0.03 TWh$_{el}$
						0.07 TWh$_{th}$	
	hydrothermal gasification	4.05 TWh$_{raw}$	70 %	70 %	50 %	35 % electricity	0.35 TWh$_{el}$
						0.35 TWh$_{el}$	
			2.84 TWh$_{raw}$	1.99 TWh$_{CH4}$	0.99 TWh$_{CH4}$	40 % heat	saves 0.13 TWh$_{el}$
						0.4 TWh$_{th}$	

*The easy storage of wood allows the combustion only during winter

Overall, using most biomass and biomass-based energy carriers for electricity and heat generation would produce around 1.8 TWh_{el} of electricity in winter, with an additional 1.9 TWh electricity saved through waste heat integration. If a seasonal gas storage of 1.5 TWh_{LHV} is considered available and filled with methane produced in summer (which is not yet considered for winter electricity production), the yield increases to a total of 2.4 TWh_{el} production in winter and an electricity saving of 2.1 TWh_{el} in winter (considering 35 % efficiency for electricity generation and 40 % for waste heat provision). The summer production of (must-run) wet biomass treatment plants is about 1.5 TWh_{CH4} (see previous section) which is sufficient to fill the considered 1.5 TWh_{LHV} gas storage

Options to further increase the electricity output would be to run the wood gasification plant only in winter (+0.95 TWh_{el} and +0.36 TWh_{el} saved). Upgrading the residual CO_2 using hydrogen in summer could increase the summer production by around 2.3 TWh_{CH4}, but would need a higher storage capacity than the considered 1.5 TWh_{CH4} for shifting surplus methane to winter. The potential for upgrading is estimated in the next section.

This calculation does not take into account competing demands for methane and wood, such as the need for high-temperature process heat. It is estimated that the heat demand for processes above 400 °C will be around 12 TWh_{th} in 2050 (BFE, 2021), meaning that it would be difficult to meet this particular demand using only biomass even without electricity generation.

5.2.4. Biomass upgrade potential

Here, the potential for upgrading the residual carbon dioxide (CO_2) of biomass methanation using hydrogen is calculated. The idea behind seasonal scheduling of biomass treatment plants is described in Chapter 2.2.3. All calculations refer to 1 unit of raw biomass. Three processes are differentiated: Anaerobic digestion (AD), hydrothermal gasification (HG) and wood gasification (WG). While the hydrogen can theoretically be directly injected into the HG and WG reactions ('hydrogen co-injection'), AD requires an additional reactor for reacting biogas with hydrogen.

Step 1: Mass of emerging CO_2

With efficiencies of 30 % for AD, 70 % for HG and 60 % for WG, the emerging methane per kWh_{raw} is:

$$AD: 1\ kWh_{raw} \xrightarrow{30\,\%\,eff.} 0.3\ kWh_{CH4}$$

$$HG: 1\ kWh_{raw} \xrightarrow{70\,\%\,eff.} 0.7\ kWh_{CH4}$$

$$WD: 1\ kWh_{raw} \xrightarrow{60\,\%\,eff.} 0.6\ kWh_{CH4}$$

Energy density methane (standard pressure): $10.5 \frac{kWh}{m^3}$

$$AD: 0.3\ kWh_{CH4} \triangleq \frac{0.3}{10.5} = 0.0286\ m^3_{CH4}$$

$$HG: 0.7\ kWh_{CH4} \triangleq \frac{0.7}{10.5} = 0.0667\ m^3_{CH4}$$

$$WG: 0.6\ kWh_{CH4} \triangleq \frac{0.6}{10.5} = 0.0571\ m^3_{CH4}$$

Volume of produced CO_2: The CH_4–CH_2 ratio from gasification/digestion is estimated to be 3:2 for AD, 7:3 for HG and 3:2 for WG.

$$AD: \frac{2}{3} \cdot 0.0286 = 0.0191 \frac{m^3_{CO2}}{kWh_{raw}}$$

$$HG: \frac{3}{7} \cdot 0.0667 = 0.0286 \frac{m^3_{CO2}}{kWh_{raw}}$$

$$WG: \frac{2}{3} \cdot 0.0571 = 0.0381 \frac{m^3_{CO2}}{kWh_{raw}}$$

Mass per volume of CO_2 at standard pressure: $1.98\frac{kg}{m^3}$

$$AD: 0.0191 \cdot 1.98 = 0.0378\frac{kg_{CO2}}{kWh_{raw}}$$

$$HG: 0.0286 \cdot 1.98 = 0.0566\frac{kg_{CO2}}{kWh_{raw}}$$

$$WG: 0.0381 \cdot 1.98 = 0.0754\frac{kg_{CO2}}{kWh_{raw}}$$

Therefore, per TWh of raw biomass, the following residual CO_2 content is produced:

$$AD: 37800\frac{t_{CO2}}{TWh_{raw}}$$

$$HG: 56600\frac{t_{CO2}}{TWh_{raw}}$$

$$WG: 75400\frac{t_{CO2}}{TWh_{raw}}$$

Step 2: Required hydrogen for upgrade

The gravimetric carbon content of CO_2 is 0.273 (12/(12+2*16))

$$AD: 0.273 \cdot 37800 = 10319\frac{t_C}{TWh_{raw}}$$

$$HG: 0.273 \cdot 56600 = 15452\frac{t_C}{TWh_{raw}}$$

$$WG: 0.273 \cdot 75400 = 20584\frac{t_C}{TWh_{raw}}$$

The carbon atom is ¾ the weight of CH_4 and the weight ratio of carbon-hydrogen is 3:1 in the methane molecule. Therefore, the amount of required H_2 is:

$$AD: \frac{10319}{3} = 3440\frac{t_{H2}}{TWh_{raw}}$$

$$HG: \frac{15452}{3} = 5151\frac{t_{H2}}{TWh_{raw}}$$

$$WG: \frac{20584}{3} = 6861\frac{t_{H2}}{TWh_{raw}}$$

However, since the methanation reaction reads: $CO_2 + 4H_2 \rightarrow CH_4 + H_2O$, double the hydrogen is required. Therefore, for upgrading all the emerging CO_2 of 1 TWh raw biomass, the following amount of hydrogen is required:

$$AD: 2 \cdot 3440 = 6880\frac{t_{H2}}{TWh_{raw}}$$

$$HG: 2 \cdot 5151 = 10302\frac{t_{H2}}{TWh_{raw}}$$

$$WG: 2 \cdot 6861 = 13722\frac{t_{H2}}{TWh_{raw}}$$

With an energy density of $33.3 \cdot 10^{-6}\frac{TWh}{t_{H2}}$ and production efficiency of 60 % from electricity this results in:

$$AD: 6880 \cdot 33.3 \cdot 10^{-6} = 0.229 \frac{TWh_{H2}}{TWh_{raw}} \triangleq 0.382 \frac{TWh_{el}}{TWh_{raw}}$$

$$HG: 10302 \cdot 33.3 \cdot 10^{-6} = 0.343 \frac{TWh_{H2}}{TWh_{raw}} \triangleq 0.572 \frac{TWh_{el}}{TWh_{raw}}$$

$$WG: 13722 \cdot 33.3 \cdot 10^{-6} = 0.457 \frac{TWh_{H2}}{TWh_{raw}} \triangleq 0.762 \frac{TWh_{el}}{TWh_{raw}}$$

Step 3: Methane potential from upgrade

The produced methane results with an energy density of $13.9 \cdot 10^{-6} \frac{TWh}{t_{CH4}}$ in:

$$AD: 10319 \frac{t_C}{TWh_{raw}} + 3440 \frac{t_{H2}}{TWh_{raw}} = 13759 \frac{t_{CH4}}{TWh_{raw}} \triangleq 13759 \cdot 13.9 \cdot 10^{-6} = 0.191 \frac{TWh_{CH4}}{TWh_{raw}}$$

$$HG: 15452 \frac{t_C}{TWh_{raw}} + 5151 \frac{t_{H2}}{TWh_{raw}} = 20603 \frac{t_{CH4}}{TWh_{raw}} \triangleq 20603 \cdot 13.9 \cdot 10^{-6} = 0.286 \frac{TWh_{CH4}}{TWh_{raw}}$$

$$WG: 20584 \frac{t_C}{TWh_{raw}} + 6861 \frac{t_{H2}}{TWh_{raw}} = 27445 \frac{t_{CH4}}{TWh_{raw}} \triangleq 27445 \cdot 13.9 \cdot 10^{-6} = 0.381 \frac{TWh_{CH4}}{TWh_{raw}}$$

If all the CO_2 emerging in summer at biomass treatment plants, which are connected to the gas grid, is upgraded using hydrogen, the following additional methane could be produced.

How to read the table: In addition to the description given in Section 5.2.2, the ‘Summer production’ option reduces the available biomass by half, as it is assumed that biomass upgrading only occurs in summer. 'Upgrade potential' describes the additional amount of methane that can be produced with hydrogen injection per unit of raw biomass (see the results of calculation step 3). 'Required electricity' shows how much electricity is needed to produce the hydrogen required for the biomass upgrade (see results of the calculation step 2).

<table>
<tr><th colspan="2">Feedstock and available processes</th><th>Exploration</th><th>Process selection</th><th>Gas network connection</th><th>Summer production</th><th>Upgrade potential</th><th>Required electricity</th></tr>
<tr><td rowspan="4">Manure
7.5 TWh_{raw}</td><td rowspan="2">Anaerobic digestion</td><td rowspan="2">80 %</td><td>80 %</td><td>50 %</td><td>50 %</td><td>19.1 %</td><td>38.2 %</td></tr>
<tr><td>4.8 TWh_{raw}</td><td>2.4 TWh_{raw}</td><td>1.2 TWh_{raw}</td><td>0.23 TWh_{CH4}</td><td>0.46 TWh_{el}</td></tr>
<tr><td rowspan="2">Hydrothermal gasification</td><td rowspan="2">6 TWh_{raw}</td><td>20 %</td><td>90 %</td><td>50 %</td><td>28.6 %</td><td>57.2 %</td></tr>
<tr><td>1.2 TWh_{raw}</td><td>1.08 TWh_{raw}</td><td>0.54 TWh_{raw}</td><td>0.15 TWh_{CH4}</td><td>0.31 TWh_{el}</td></tr>
<tr><td rowspan="2">Wood
14 TWh_{raw}</td><td rowspan="2">Gasification</td><td>90 %</td><td>70 %*</td><td>90 %</td><td>50 %</td><td>38.1 %</td><td>76.2 %</td></tr>
<tr><td>12.9 TWh_{raw}</td><td>8.82 TWh_{raw}</td><td>7.94 TWh_{raw}</td><td>3.97 TWh_{raw}</td><td>1.51 TWh_{CH4}</td><td>3.02 TWh_{el}</td></tr>
<tr><td rowspan="4">Other biomass
4.5 TWh_{raw}</td><td rowspan="2">Anaerobic digestion</td><td rowspan="2">90 %</td><td>30 %</td><td>80 %</td><td>50%</td><td>19.1 %</td><td>38.2 %</td></tr>
<tr><td>1.22 TWh_{raw}</td><td>0.97 TWh_{raw}</td><td>0.49 TWh_{raw}</td><td>0.093 TWh_{CH4}</td><td>0.19 TWh_{el}</td></tr>
<tr><td rowspan="2">Hydrothermal gasification</td><td rowspan="2">4.05 TWh_{raw}</td><td>70 %</td><td>90 %</td><td>50%</td><td>28.6 %</td><td>57.2 %</td></tr>
<tr><td>2.84 TWh_{raw}</td><td>2.56 TWh_{raw}</td><td>1.28 TWh_{raw}</td><td>0.36 TWh_{CH4}</td><td>0.73 TWh_{el}</td></tr>
</table>

*Not all wood is gasified

The total upgrade potential is about 2.3 TWh_{CH4}, which would require about 4.7 TWh_{el} of electricity for hydrogen production in summer. The majority of the potential (1.51 TWh_{CH4}) is provided by wood gasification plants. The potential for biomass upgrade is greater if the anaerobic digestion residue, which contains residual carbon, is subsequently fed into hydrothermal gasifiers and upgraded there.