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ASSESSING THE POTENTIAL OF LARGE-SCALE SEASONAL THERMAL ENERGY STORAGE IN SWITZERLAND USING INTEGRATED GIS-BASED ENERGY MODELLING AND OPTIMIZATION

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Summary

Seasonal thermal energy storage (STES) can mitigate the seasonal mismatch between renewable energy supply and heat demand, particularly when integrated with district heating networks. This work assesses the potential of large-scale STES in Switzerland with a methodology that couples national-scale energy-system modelling, GIS-based spatial screening, and district-level optimisation. An automated scanner identified 226 candidate district-heating areas with a current heat demand of about 20.6 TWh/year. These areas were classified into nine archetypes according to their accessible heat sources and storage options, and we optimised one representative district per archetype with the open-source *optihood* mixed-integer linear programming framework, extended for this study with pit, borehole and tank seasonal-storage models. Under the considered assumptions, STES was selected in every archetype, where it can lower system costs, improve the utilisation of waste heat, and allow a more favourable operation of the heat pumps. Extrapolated to the national level and soft-linked to the Swiss EnergyScope model, the results indicate a deployable STES potential of about 2.94 TWh, roughly 14 % of the identified heat demand, with a corresponding land requirement on the order of 4.76 km^2. A transition-pathway analysis shows that the timing of deployment has a strong effect on transition costs and climate impact.

Keywords: seasonal thermal energy storage, district heating, GIS, energy-system optimisation, decarbonisation

Field of application for the findings: Energy-system planning, district-heating design, large-scale renewable integration

Addressed audience: Researchers, utilities, planners, technology developers, and policy makers

1. Introduction

Heating and domestic hot water account for a dominant share of final energy demand and greenhouse-gas emissions in Switzerland (about 50 % overall and close to two thirds in winter), mirroring the wider European context. National decarbonisation pathways consistently identify large-scale electrification through heat pumps, combined with a strong expansion of renewable electricity, as the most cost-effective route to long-term climate targets (European Commission, Directorate-General for Energy, 2023). This transition, however, requires substantial reinforcement of electrical infrastructure to accommodate the additional power demand from replacing fossil boilers, and it does not by itself resolve the pronounced seasonal mismatch between renewable availability and space-heating demand.

District heating (DH) offers a complementary route: it enables efficient integration of renewable and waste heat and provides flexibility that is difficult to obtain from distributed individual systems. In particular, large-scale thermal energy storage (LSTES) coupled to DH networks can cost-effectively shift heat from periods of abundant supply to periods of high demand, covering both short-term and seasonal balancing needs. National energy-system analyses for Switzerland, such as SolTherm2050 (Berger et al., 2021), indicate that several TWh of seasonal thermal storage may be required by 2050 to shift surplus summer renewable energy towards winter heat demand. Large-scale seasonal thermal energy storage (STES), integrated with DH, therefore emerges as a critical system component.

While national-scale models quantify the magnitude of required storage capacity, they typically represent Switzerland as a single aggregated region and do not resolve spatial constraints, local feasibility, or technology-specific deployment limits. Conversely, local or district-level studies can assess technical feasibility in detail but often lack consistency with national boundary conditions such as electricity-price seasonality, emission constraints, imports and exports, and long-term system evolution. Bridging this gap between top-down system needs and bottom-up spatial feasibility is essential for a realistic assessment of STES potential and its impact at national scale.

This study addresses this gap by developing an integrated methodology that combines a country-wide GIS layer superimposing heat-demand density with heat-source and storage potentials, an automated bottom-up optimisation of representative districts, and a national top-down energy-system model. The specific objectives are to (i) map the theoretical maximum potential of LSTES in Switzerland, (ii) build a GIS-based optimisation framework able to assess where and under which conditions LSTES is cost-competitive, and (iii) use transition-pathway analysis to identify the boundary conditions and incentives required to deploy the necessary storage capacity by 2050. This paper summarises the methodology and the main results.

2. Methodology

To link national energy-system requirements with local deployment feasibility, this study couples top-down energy-system modelling, GIS-based spatial analysis, and bottom-up district-level optimisation, as illustrated in Figure 1. The framework integrates three complementary components.

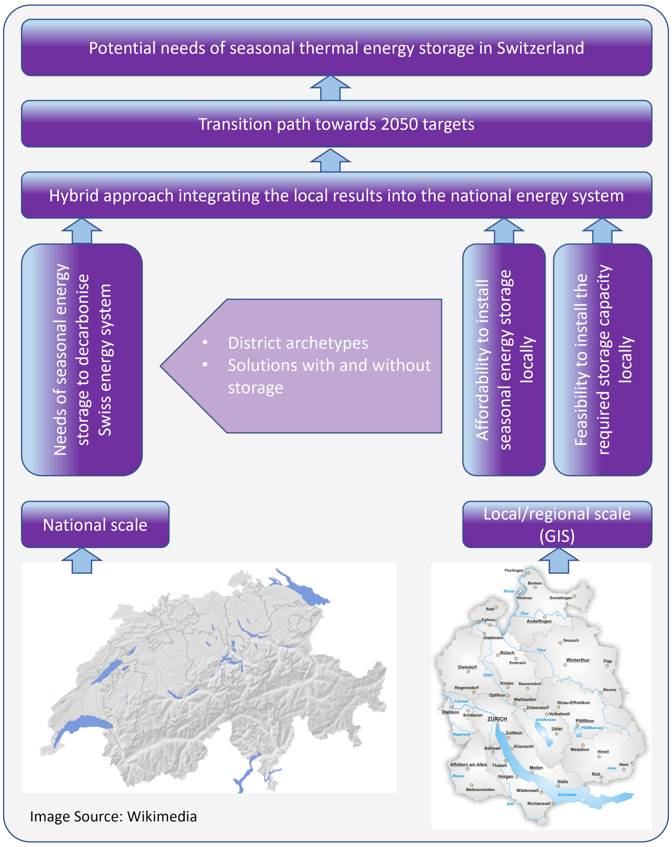

Figure 1: Conceptual methodology combining top-down and bottom-up energy modelling to assess the potential of large-scale seasonal thermal energy storage.

First, national-scale modelling with the Swiss EnergyScope (SES) framework defines consistent boundary conditions relevant to seasonal storage, including long-term decarbonisation targets, electricity-price seasonality, and the overall magnitude of required storage. SES is a mixed-integer linear programming (MILP) model that determines the cost-optimal configuration of technologies, energy carriers, and infrastructure for the entire Swiss energy system across electricity, heat, transport, and industry (Moret, 2017).

Second, a GIS-based screening approach identifies candidate district-heating areas across Switzerland. Building-level heat-demand data are aggregated spatially and analysed with a dedicated district-scanning algorithm based on heat-density thresholds and spatial contiguity, following established methodologies for mapping district-heating potential (Nussbaumer et al., 2020) and extending them to explicitly include the feasibility of large-scale thermal storage.

Third, the identified districts are classified into archetypes according to accessible heat sources and feasible storage options. For each archetype, a representative district is selected for detailed techno-economic optimisation with a MILP energy-system model. Results are subsequently extrapolated from representative districts to the national level, and soft-linked back into SES so that national cost-optimisation accounts for local techno-economic feasibility. A transition-pathway analysis finally extends the assessment from isolated target years to the evolution of the system over time.

3. GIS-based district identification and archetypes

3.1 GIS data and heat demand

A country-wide GIS database was assembled that superimposes heat-demand density with the thermal source and storage potentials relevant to seasonal storage: municipal and industrial waste heat, waste-incineration plants, river, lake and groundwater potentials, borehole feasibility, and a purpose-built pit-storage suitability layer. A representative subset of these superimposed layers for north-east Switzerland is shown in Figure 2; the full layer stack is used to determine, for each candidate district, which heat sources and storage options are locally available. For heat demand, we compared three sources: the Swisstopo and EU HotMaps 100×100 m datasets and EPFL's building-resolved QBuildings database (Girardin, 2012). QBuildings proved the most accurate, and it also provides the building attributes (energy reference area, roof and façade area, heating system, PV potential) required as input to the bottom-up model. Building demand was aggregated into 1 ha hexagonal cells to match the resolution of the other maps. Hexagons were used rather than squares because each cell then has more direct neighbours, so more of the surrounding area is taken into account when the scanner searches for contiguous district-heating candidates.

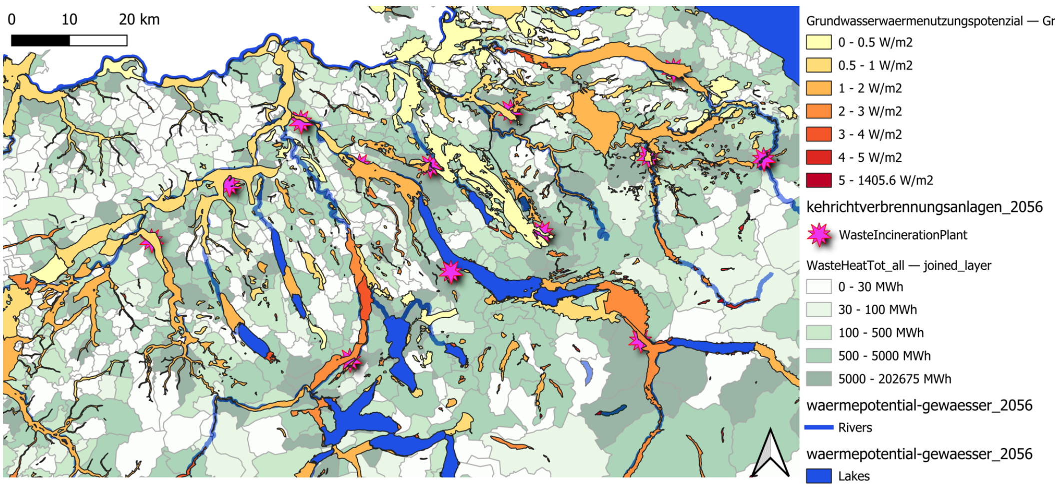

Figure 2: Subset of the superimposed GIS potential maps for north-east Switzerland (ground-water, waste incinerators, municipal waste heat, river and lake potentials). The full set of layers, including PV, borehole and pit-storage potential, is used to assign the available heat sources and storage options to each district.

From this heat-demand layer, a dedicated scanner extracts contiguous clusters suitable for district heating, following the economic-viability criteria of Nussbaumer et al. (2020): an initial cluster must contain at least four connected hectares above 700 MWh/(a·ha), which are then extended with adjacent cells above 400 MWh/(a·ha). Imposing spatial contiguity reduces the problem to a tractable covering-location problem. Applied to the whole country, the scanner identified 226 potential district-heating areas. A sensitivity analysis of the demand thresholds indicates that these reference values are conservative, so the resulting number of viable networks, particularly in rural areas, should be regarded as a lower bound.

3.2 District archetypes

Each district was cross-referenced with the source and storage potential maps. Because optimising all 226 districts individually is computationally prohibitive, the districts were grouped into archetypes defined by their accessible heat source, ordered by increasing cost of exploitation: waste incinerator (full / partial coverage), municipal waste heat (full / partial coverage), river, groundwater, lake, and a "no source" class where only storage is possible. The river category was split into "River small" and "River large" to separate the three metropolitan districts (Zürich, Basel, Geneva), whose demand dominates the class, giving nine archetypes in total (Figure 3). For each archetype the representative district is the one whose demand is closest to the archetype average, except for River large where the largest (Zürich) district is used to ensure the result scales to the full class demand. The total current heat demand across all identified districts is 20.6 TWh/year (Tab. 1). As an illustration, Fig. 4 maps the classified district-heating candidates in two example cities, Lausanne and Bern, each coloured by its assigned archetype.

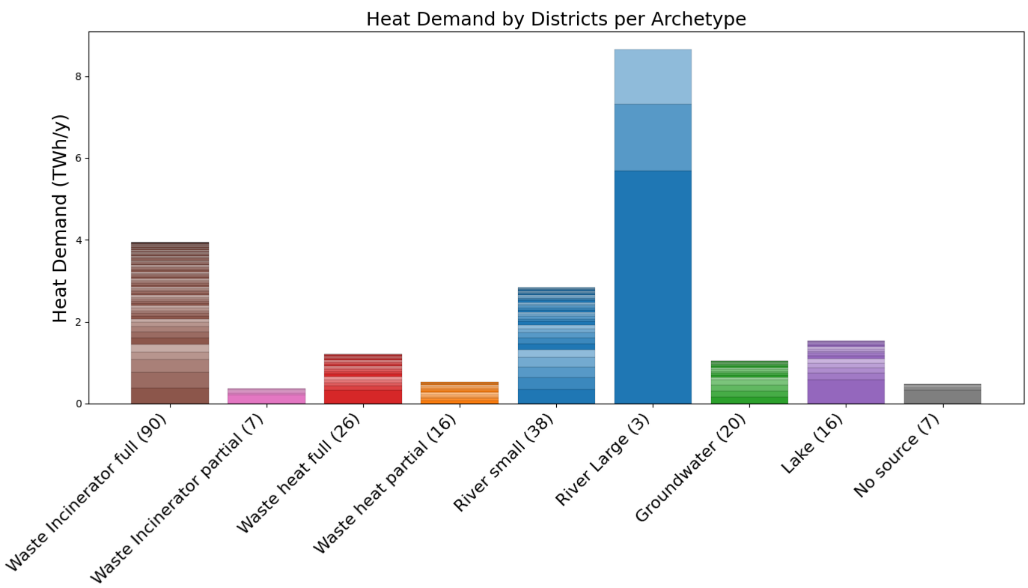

Figure 3: The nine district archetypes and the districts within each. Every district is represented by a bar segment proportional to its annual heat demand; the number of districts per archetype is given in brackets.

4. Bottom-up optimisation of representative districts

4.1 The optihood framework and seasonal-storage models

Representative districts were optimised with *optihood* (Dimri et al., 2023), an open-source MILP energy-system optimisation tool built on the *oemof* framework (Hilpert et al., 2018). Operated in investment mode, it jointly selects and sizes conversion and storage technologies while minimising the total annualised system cost (annualised investment plus operation), subject to hourly energy balances over a full year. An automated GIS-to-optihood pipeline translates the spatial and building data of each district into the required scenario files; buildings are aggregated by usage type to keep the problem tractable, and hourly demand profiles are generated from the building attributes and standard load profiles.

Three seasonal-storage technologies were implemented specifically for this study, namely tank (TTES), pit

Table 1: Current annual heat demand of the identified districts, by archetype (from the GIS scanner).

Archetype	**Heat demand [TWh/y]**
Waste incinerator (full)	3.936
Waste incinerator (partial)	0.359
Waste heat (full)	1.211
Waste heat (partial)	0.522
River (small)	2.831
River (large)	8.650
Groundwater	1.045
Lake	1.538
No source	0.482
Total	**20.574**

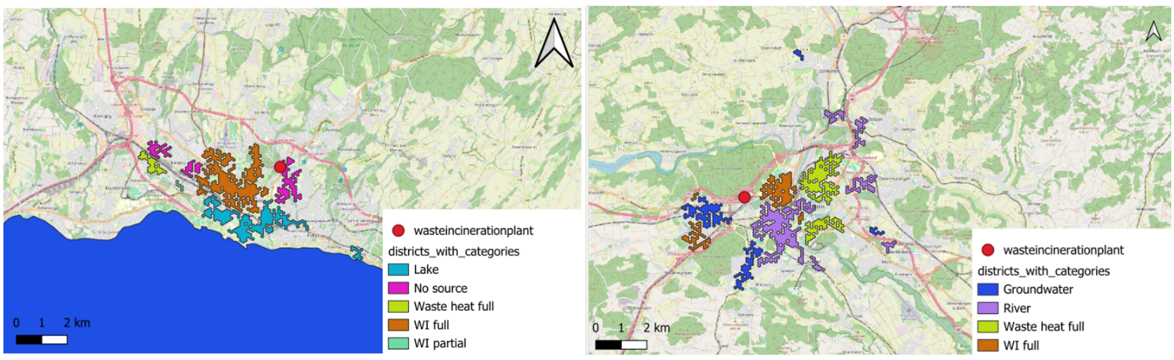

Figure 4: Identified district-heating candidates classified by archetype for two example cities, Lausanne (left) and Bern (right). Colours denote the assigned archetype and the red marker shows the associated waste-incineration plant. The available heat source, and hence the archetype, varies from district to district even within one city.

(PTES) and borehole (BTES) thermal energy storage, all built on top of optihood's existing two-node storage model. Investment costs and geometry-dependent heat losses are represented through piece-wise linear functions of storage capacity, with geometries following Van der Heijde et al. (2019). An aquifer option is included as a low-temperature source for the central heat pump rather than as a charged/discharged store. The key modelling assumptions and resulting energy densities are summarised in Table 2.

Table 2: Key assumptions for the seasonal-storage models implemented in optihood. The nominal thermal capacity is $E_{\text{nom}} = \rho_E V$ with V in m^3.

Technology	**Geometry assumption**	T_{high}	T_{low}	**Energy density** ρ_E
TTES	Cylindrical water tank, $h/D = 1$	90 °C	40 °C	58 kWh/m^3
PTES	Inverted truncated pyramid	80 °C	40 °C	47 kWh/m^3
BTES	Cylindrical borehole field, 200 m depth	80 °C	40 °C	30 kWh/m^3

4.2 Optimisation results

Optimisations used weather and demand profiles for 2023. Seasonal storage was selected in every archetype (Figure 5).

The relative TES capacity, expressed as storage capacity over annual heat demand, ranges from about 4 % for the Lake archetype to 29 % for the Waste incinerator (full) archetype. Where a low-temperature water source is available (river, groundwater, lake), a central water-source heat pump supplies a large share of the demand, and for the river case it can cover the demand entirely. Biomass, and for groundwater and lake an auxiliary air-source heat pump, supply the rest. For high-temperature sources (waste heat, waste incineration) the source covers most of the demand directly and no large heat pump is required; the "full" cases show the largest relative

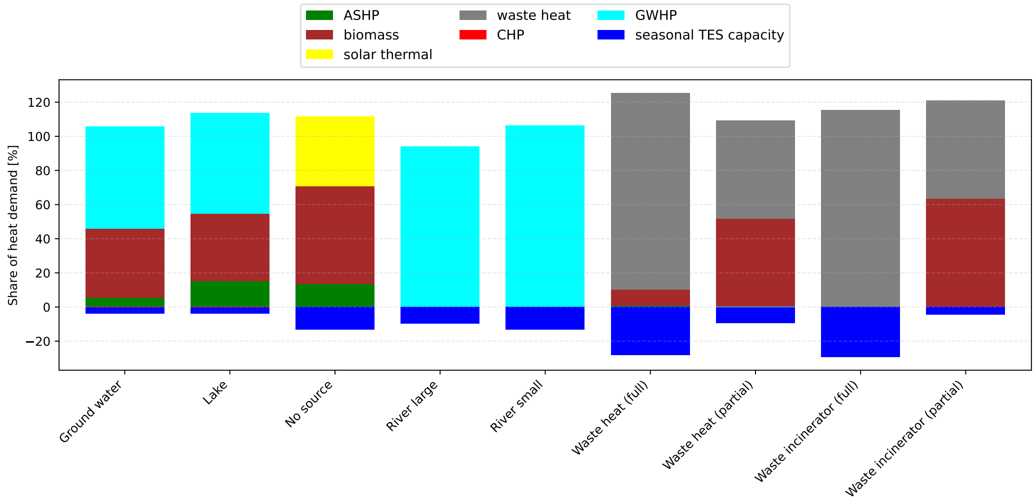

Figure 5: Positive axis: share of heat demand supplied by each technology per archetype (values above 100 % reflect system thermal losses). Negative axis: seasonal TES capacity relative to heat demand.

storage because the near-constant annual waste-heat supply produces a summer surplus that must be shifted to winter. The only archetype without waste or water sources relies on solar thermal collectors for roughly 40 % of demand, again with substantial storage to absorb the summer surplus.

Absolute seasonal-storage volumes span three orders of magnitude, from about 4,000 m^3 (Waste incinerator, partial) to roughly 11.8 million m^3 (River large), and scale almost directly with each archetype's annual heat demand (Figure 6): the largest stores sit where the most heat must be shifted from summer to winter. Apart from the industry-dominated Waste incinerator (partial) case, whose levelised cost of energy (LCOE) exceeds 150 CHF/MWh because a uniform 330 CHF/MWh electricity price is applied to a large electricity demand, the archetypes reach a competitive LCOE of 75–100 CHF/MWh (network costs excluded). The waste-heat systems are the cheapest, as their heat is assumed available at 30 CHF/MWh. The number of storage cycles per year ranges from about 1 for the waste-heat (full) cases, which behave as purely seasonal stores with smooth state-of-charge profiles (Figure 7), to over 12 for the Lake archetype, whose small store cycles frequently. In most cases the optimal PV capacity corresponds to 30–50 % of electricity consumption, and the battery storage stays small ($\leq$1.8 h of PV peak) across all archetypes.

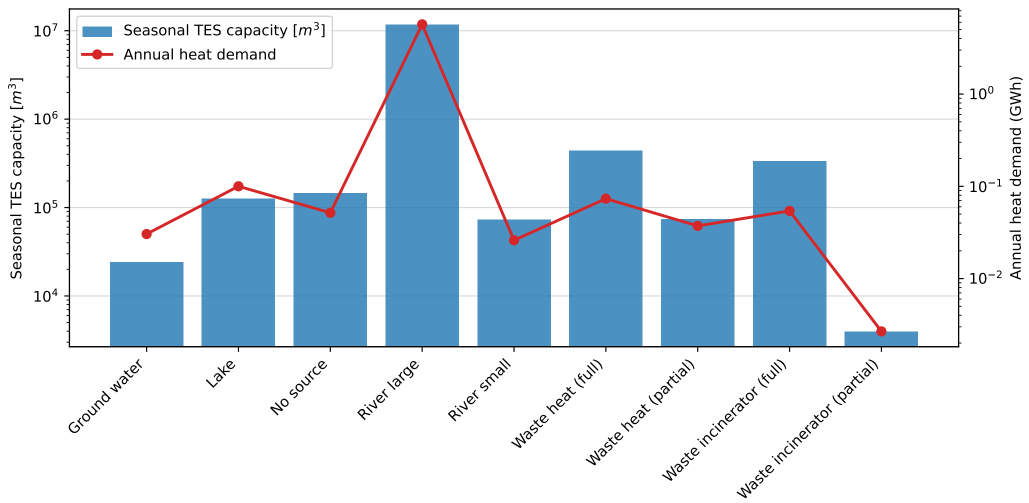

Figure 6: Absolute seasonal TES capacity (bars, left axis) and annual heat demand (right axis) for each archetype. The optimised storage volume scales almost directly with annual heat demand.

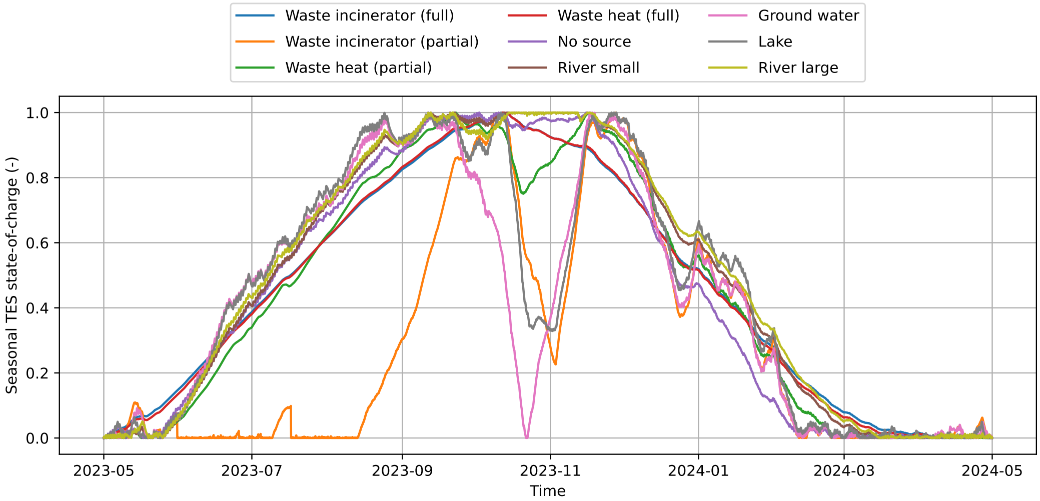

Figure 7: Seasonal TES state of charge over the year for all archetypes. Storage empties around April–May and peaks around October; waste-heat (full) cases show smooth, near-seasonal profiles.

4.3 Land requirements

The optimised storage volumes were translated into indicative surface areas per district. For BTES the active storage height is taken as the 200 m borehole depth, so a 100,000 m^3 field needs only about 500 m^2 of surface; for PTES and TTES the footprint follows from the linearised geometry and an assumed 20 m tank height, respectively. Both BTES and PTES can be covered after construction, leaving the surface usable for parks, sports fields or parking (Reuss, 2021). Distributing the archetype storage volumes across the districts of each class gives a national land requirement of about 4.76 km^2 (Table 3), which is a small footprint at national scale. Because the archetype is defined by its heat source rather than its storage technology, a store that is infeasible at a given site (e.g. a pit) can be substituted by another technology of different energy density, trading surface area against cost.

Table 3: Indicative national land requirement for seasonal storage by archetype: per-installation footprint, number of installations, and total surface area (1 football field = 7,140 m^2).

Archetype	**Type**	**Size [m^3]**	**Area/inst. [m^2]**	**No.**	**Total [m^2]**
WI full	PTES	337,360	28,795	73	2,097,927
WI partial	BTES	3,976	20	134	2,667
Waste heat full	PTES	493,453	34,344	17	566,718
Waste heat partial	PTES	73,787	10,452	14	146,972
River small	PTES	73,491	10,424	109	1,137,414
River large	PTES	11,812,967	308,191	1.5	468,516
Groundwater	PTES	24,202	4,971	34	171,245
Lake	BTES	125,811	629	15	9,683
No source	PTES	146,151	16,486	9	154,257
Total					**≈4.76 km^2**

5. National-scale and hybrid modelling

5.1 Snapshot scenarios with Swiss Energy Scope

At the national scale, SES optimises the whole Swiss energy system at monthly resolution. It does not resolve temperature explicitly but distinguishes a low- and a high-temperature heat layer, and seasonal storage acts in the high-temperature layer, consistent with the 75–150 °C waste-heat potential of Burg et al. (2023). Before the bottom-up results were coupled in, a purely top-down analysis mapped how the need for seasonal storage responds to the main uncertainties of the 2050 system. Each case is optimised independently for the target year under perfect foresight, across 32 internally consistent scenarios of the CROSS framework (Marcucci et al., 2022) built from four uncertainty levers: geographical scope (national vs. international cooperation), degree of integration with neighbouring countries, climate pathway (RCP 2.6–8.5), and technology availability (conservative vs. progressive). Only the 16 progressive scenarios include thermal storage.

Across all of them a robust seasonal pattern emerges (Figure 8): storage charges in summer, with a peak concentrated in July and August, and discharges in winter, most strongly between November and March. Scope and integration change mainly the magnitude of the storage swings, with domestic, low-integration cases storing more because their tighter constraints leave less cross-border flexibility. Climate shifts the timing and composition of storage use rather than its qualitative role: under constant-climate assumptions the activity spreads over the year and gains an additional spring charging period, whereas the warmer RCP scenarios concentrate it into a single summer charge followed by winter discharge. In all of these scenarios Switzerland is treated as a single node, a limitation the hybrid coupling in the next section is designed to address.

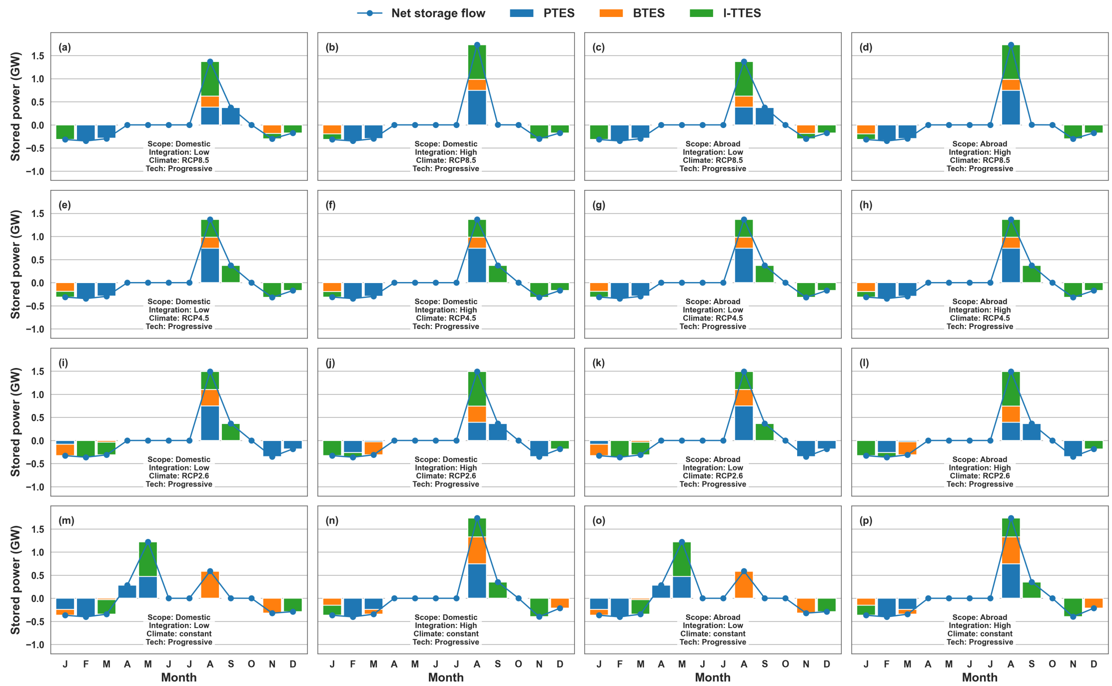

Figure 8: Monthly net thermal-storage flows for the Swiss energy system in 2050 across the progressive CROSS scenarios (PTES, BTES, l-TTES). Positive values denote net summer charging, negative values net winter discharge.

5.2 Hybrid soft-linking and national impacts

Representing Switzerland as a single node cannot say whether the required storage can be sited locally. Following Schnidrig et al. (2024), the bottom-up and top-down models were therefore soft-linked in three phases: districts are typified into the nine archetypes; each archetype is optimised with optihood in two variants, with and without seasonal storage; and SES selects, per archetype, the configuration that minimises national system cost, scaling each representative district by the share of national heat demand it represents. The largest scaling weights fall on the WI partial and River small archetypes, while River large represents only a few metropolitan districts but enters with a high heat demand. Storage is thus an endogenous national outcome rather than an imposed assumption, and it concentrates in the archetypes where heat demand, resource availability and scaling weight make seasonal shifting most valuable. In the analysed case the national model selects storage for every archetype, so the hybrid outcome coincides with the with-storage configuration.

Comparing the storage and no-storage configurations isolates the system value of seasonal storage (Figure 9). Biomass imports fall in every archetype, since seasonal storage substitutes for dispatchable biomass as the winter balancing resource, and they are almost eliminated for River large, River small and Waste incinerator (full). The electricity response is more heterogeneous: imports decrease for waste-heat-rich and “no source” archetypes, but increase for river-, groundwater- and lake-based archetypes, where storage operation is coupled to large heat pumps. These local changes add up to a marked shift in the national energy balance: enabling storage cuts biomass imports by about 11 TWh/year (roughly 85 %) and displaces the remaining oil-boiler heat entirely, while local low-voltage PV generation rises by about 6.5 TWh/year and the electricity drawn from the medium-voltage grid falls by about 5.1 TWh/year. The net supply of low-temperature heat is essentially unchanged (91.9 vs. 91.8 TWh/year), so the effect is a change in the supply mix rather than in total demand. At the system level the storage-enabled configuration raises the annualised investment cost from about 8.0 to 8.5 BCHF/year (mostly low-voltage PV, decentralised heat pumps and district-heating infrastructure), while annual operation and maintenance costs fall from about 4.6 to 3.4 BCHF/year, driven overwhelmingly by reduced biomass and light-fuel-oil use. The total annual system cost is therefore lower with storage, about 11.9 instead of 12.6 BCHF/year, so seasonal storage trades higher upfront investment for substantially lower operating costs.

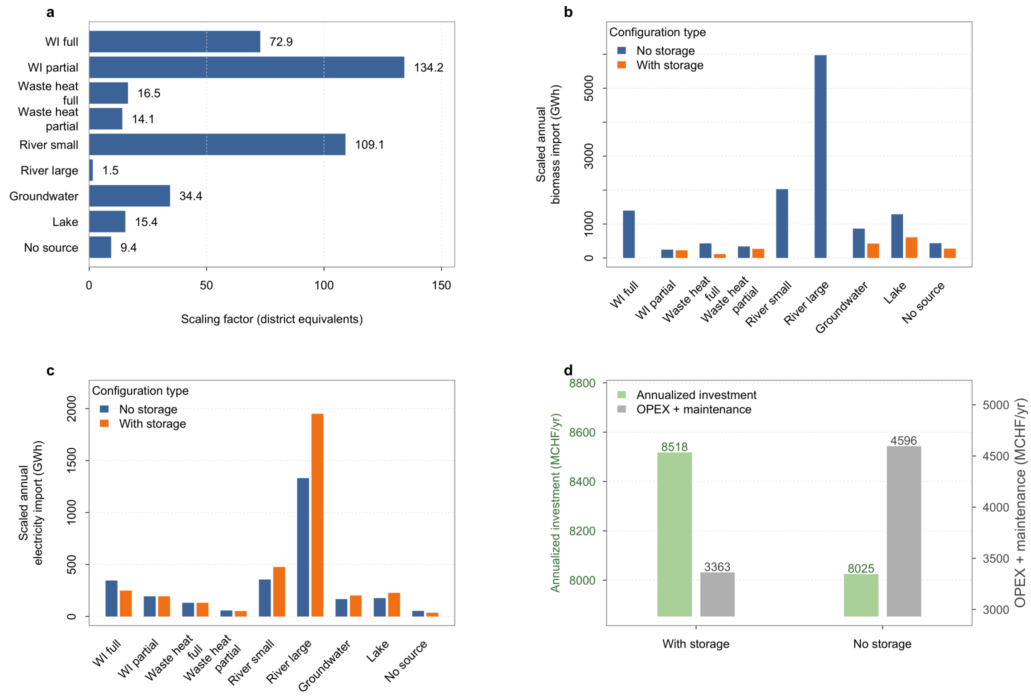

Figure 9: Scaling factors of district archetypes and resulting national-level impacts. Panel (a) reports the scaling factor of each archetype in district-equivalent terms. Panels (b) and (c) show scaled annual biomass and electricity imports for configurations with and without seasonal storage, where the with storage configuration is also the configuration chosen by the hybrid approach. Panel (d) compares total capital and operational expenditures for the two configurations.

5.3 Transition pathways

Snapshot optima describe a target state but not how to reach it. A multi-period transition-pathway formulation (Limpens, 2021) links five-year steps between 2025 and 2050 through inter-temporal capacity constraints. For a fixed 2050 storage target (2869 GWh), alternative deployment timings were compared against an endpoint-constrained minimum-cost reference in which only the 2025 and 2050 capacities are fixed (Figure 10). Timing matters, but the penalties are modest: forcing immediate build-out by 2030 raises the cumulative annualised storage cost by about 926 MCHF relative to the reference, while an extremely slow build-out is essentially identical to it. The corresponding total system-transition-cost penalty is much smaller, about 192 MCHF for the immediate pathway, because earlier storage lets the system build less district-heating network and heat-pump capacity elsewhere. The reference pathway is not a last-minute build-out: it installs a substantial amount of storage early (about 900 GWh by 2030) and then steps up to the full target in the final period. The climate response is non-monotonic but mostly favourable: every pathway except the extremely slow one lowers cumulative emissions relative to the reference, with the largest reduction (about 1,540 ktCO_2-eq) for the fast pathway rather than for immediate deployment. The same final capacity can therefore be reached through very different schedules with different costs and emissions, which is why dedicated early-stage incentives matter for storage that is not yet cost-optimal under today's markets.

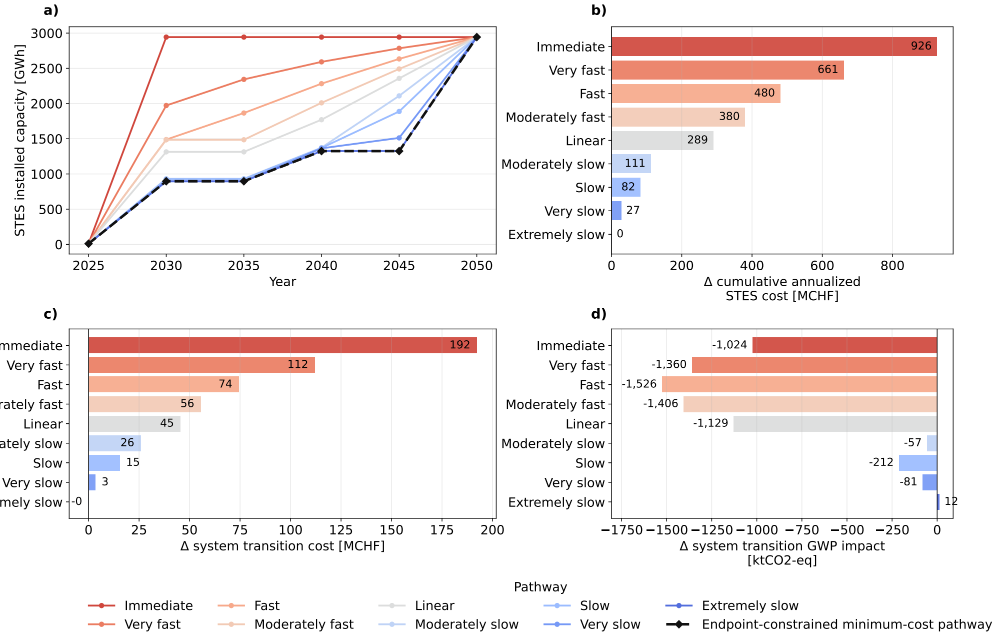

Figure 10: Effect of alternative STES deployment timings for a fixed 2050 capacity target. Panel (a): installed capacity trajectories. Panels (b)–(d): change in cumulative annualised STES cost, system transition cost, and cumulative transition GWP impact relative to the cost-optimal reference.

6. Discussion

The 20.6 TWh/year of heat demand in the identified districts agrees well with independent Swiss estimates of a realisable thermal-network potential of 17–22 TWh/year (Bundesrat der Schweizerischen Eidgenossenschaft, 2021). It should be read as an upper technical bound rather than a forecast: it is based on today's demand, whereas the EP2050+ scenarios (Prognos AG et al., 2021) project declining residential heat demand through renovation, efficiency and climate warming, with residential district-heating supply in 2050 between 2.6 and 9.2 TWh/year (about 3–13 TWh/year including neighbourhood-scale networks). Our estimate therefore represents the maximum extent of areas that are technically suitable for district heating, not a forecast of how much will actually be built.

Scaled to the national level, the bottom-up results give a deployable seasonal-storage potential of about 2.94 TWh, roughly 14 % of the identified heat demand (Table 4). Two archetypes dominate: waste incinerator (full) at 1155 GWh and river large at 844 GWh, together close to two thirds of the total, both driven by high district heat demand rather than by unusually large stores per unit demand. Measured against demand, the waste-heat-rich archetypes carry the most storage (29 % for waste incinerator full, 28 % for waste heat full), because near-constant annual waste heat forces the summer surplus to be held until winter, whereas groundwater and lake archetypes sit near 4 % because their heat pumps can follow demand. Pit storage is the most frequently selected technology under the considered assumptions, but no single technology is universally optimal: the choice depends on heat source, land availability and district characteristics, which is why the technology choice is resolved here per archetype rather than assumed uniform at the national scale.

These figures should be read within a few clearly stated assumptions, some of which make the estimate cautious and some of which work the other way. The bottom-up framework does not yet account for the electricity-network reinforcement costs associated with high peak electrical loads, for example when the optimisation selects a large central heat pump. Including these costs could make configurations with lower peak electricity demand, including those enabled by seasonal storage, comparatively more favourable; the reported STES potential is therefore conservative in this respect. The demand thresholds and the use of today's heat demand, however, push in the opposite direction. The archetype approach keeps the national analysis tractable while

Table 4: Deployable seasonal-storage capacity per archetype, from the bottom-up optimisation scaled to the national level with the archetype scaling factors.

Archetype	Storage capacity [GWh]
Waste incinerator (full)	1155.2
Waste incinerator (partial)	16.0
Waste heat (full)	340.8
Waste heat (partial)	48.8
River (small)	376.9
River (large)	844.0
Groundwater	39.2
Lake	58.1
No source	64.3
Total	**2943.3**

smoothing over some local diversity, and future demand, technology costs, and policy will refine the numbers further. District-heating network costs are not included in the district LCOE values, so absolute costs would be somewhat higher.

7. Conclusions

The study combined country-wide GIS screening, district-scale bottom-up optimisation, and national top-down modelling in a single framework, in order to assess not only how much seasonal thermal energy storage Switzerland may need, but whether that capacity can realistically be deployed under local constraints. An automated scanner identified 226 candidate district-heating areas covering 20.6 TWh/year of current heat demand, grouped into nine source-based archetypes and optimised with an LSTES-extended optihood framework through an automated GIS-to-optihood pipeline.

The bottom-up results show that seasonal storage is an economically attractive component of district energy systems across a wide range of local conditions: it was selected in every archetype, lowered system costs, improved waste-heat utilisation, and enabled more favourable heat-pump operation, with benefits tied to the availability of low-cost heat and the ability to shift production from low-price to high-demand periods. Extrapolated nationally, about 2.94 TWh of seasonal storage (roughly 14 % of the identified heat demand) could be deployed within the available spatial potential, requiring about 4.76 km^2 of surface area, much of which can remain usable after construction.

The hybrid soft-linking of bottom-up configurations into Swiss EnergyScope is the central methodological contribution of this work: it lets national cost-optimisation choose storage per archetype on the basis of local techno-economic feasibility. In the national system, enabling seasonal storage strongly reduces biomass dependence and smooths winter heat supply, trading a modest rise in annualised investment (about 8.0 to 8.5 BCHF/year) for a larger fall in operating cost (about 4.6 to 3.4 BCHF/year), and thus a lower total annual system cost (about 12.6 to 11.9 BCHF/year), while shifting the heat-supply mix towards a more electricity-coupled configuration whose electricity impact is archetype-dependent. Finally, the transition-pathway analysis shows that the 2050 capacity target alone does not determine the transition: the timing of deployment materially changes cumulative costs and climate impact, so early-stage incentives and regulatory support are likely to be needed to deploy storage that is not yet cost-optimal under current market conditions but is required to reach the 2050 targets.

Taken together, the results demonstrate that large-scale seasonal thermal energy storage can play a significant role in the Swiss energy transition, that sufficient technical and spatial potential exists for its deployment, and that integrated, spatially resolved modelling is essential to assess both the need for and the feasibility of future storage infrastructure. Future work will refine the GIS constraints (geology, protection zones, permitting), add industrial heat and cooling demand and the low-temperature/anergy networks that serve both, strengthen the coupling between the bottom-up and top-down models, and use the transition framework to test concrete policy instruments.

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