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Research paper

# Techno-economic assessment of Waste-to-Energy-based Power-to-Methane systems for regional gas networks

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ABSTRACT

Power-to-Methane (PtM) offers a pathway to integrate renewable electricity into gas networks by converting captured $CO_2$ and hydrogen into synthetic natural gas (SNG). Waste-to-Energy (WtE) plants constitute attractive anchor points for PtM due to their continuous $CO_2$ emissions and availability of high-temperature waste heat. This study presents a system-level techno-economic assessment of WtE-based PtM deployment in a Swiss gas distribution network, using an hourly, multi-node optimization model formulated as a mixed-integer linear program. The analysis considers $CO_2$ capture at WtE plants, hydrogen production via electrolysis, methanation, transport infrastructure, and short- and seasonal storage. Multiple scenarios are evaluated, including grid-based PtM, fully renewable configurations with hydrogen imports, and hybrid systems combining local SNG production with natural gas imports under different $CO_2$ price levels. Costs are assessed using the levelized cost of methane (LCOM). Results show that SNG production is primarily constrained by renewable electricity availability rather than $CO_2$ supply. Seasonal storage of methane strongly reduces system costs by enabling production during periods of high renewable availability while meeting winter demand. Fully renewable configurations achieve LCOM values 0.13–0.24 CHF/kWh. This result relies on low-emission hydrogen imports via the planned European Hydrogen Backbone and on deployment of seasonal LNG storage. In contrast, hybrid systems combining natural gas imports with local SNG production rely solely on methane imports under current $CO_2$ prices, with SNG becoming economically viable only at higher carbon price levels, albeit at increased total system costs. Across all cases, operational expenditures dominate total system costs, driven mainly by electricity and imports. Overall, the results highlight the central role of low-carbon electricity availability, storage integration, and policy signals in determining the techno-economic performance of WtE-based PtM. The findings provide insights for the design and planning of energy conversion systems aiming to defossilize regional gas networks.

## 1. Introduction

Modern waste incineration plants are now also called Waste-to-Energy (WtE) plants as they supply power and district heat while avoiding methane emissions from landfills. This is critical because methane's warming effect is very high in the near term ($\approx 81–83 \times CO_2$ over 20 years) and still large on a 100-year basis ($\approx 27–30 \times CO_2$) according to IPCC-based reporting (Forster et al., 2021). Yet WtE plants still emit $CO_2$ (biogenic and fossil), motivating carbon capture, utilization and storage (CCUS).

In the European Union, waste incineration plants are not included in the EU Emissions Trading System (ETS), but Directive 2023/959 stipulates that they are currently assessing their inclusion from 2028 (European Parliament and Council of the European Union, 2023). In Switzerland, the Climate and Innovation Act (in force from 2025) anchors the net-zero 2050 target and is accompanied by a federal CCS/Carbon Dioxide Removal (CDR) roadmap (Federal council, 2022). The Swiss ETS has been revised in line with the EU ETS. The updated legal framework explicitly recognizes $CO_2$ capture and cross-border transport for storage, with implementing ordinances phased in from 2025 (Federal Office for the Environment FOEN, 2025). Importantly, the Swiss waste industry has agreed with the Confederation to commission $CO_2$ capture systems at municipal plants by 2030 (initial capacity ≥ 100 $ktCO_2\ yr^{-1}$) (Swiss Federal Administration (UVEK), 2024). Federal guidance identifies waste incineration plants as a "hard-to-abate" sector where capture and utilization or removal will be required. Nevertheless, it remains unclear whether plants will need to store the captured carbon to qualify as sinks or whether utilization pathways will be accepted.

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**Nomenclature**

| | |
|---|---|
| CAPEX | Capital expenditure |
| CC | Carbon capture |
| CCS | Carbon capture and storage |
| CCU | Carbon capture and usage |
| CEPCI | Chemical Engineering Plant Cost Index |
| DeCIRRA | Decarbonization of Cities and Regions with Renewable Gases |
| EHB | European Hydrogen Backbone |
| ETS | Emissions Trading System |
| HHV | High heating value |
| LCA | Life cycle assessment |
| LCOM | Levelized Cost of Methane |
| LCOSNG | Levelized Cost of Synthetic Natural Gas |
| MILP | Mixed-Integer Linear Programming |
| NG | Natural gas |
| OPEX | Operational expenditure |
| PEM | Proton exchange membrane |
| PPA | Power Purchase Agreement |
| PtG | Power-to-Gas |
| PtM | Power-to-Methane |
| PtX | Power-to-X |
| PV | Solar photovoltaic |
| RE | Renewable energy |
| RoR | Run-of-River |
| SNG | Synthetic Natural Gas |
| SOEC | Solid oxide electrolyzer cell |
| TEA | Techno-economic analysis |
| WtE | Waste-to-Energy |
| WWTP | Wastewater treatment plant |

In practice, the most common $CO_2$ utilization pathway at WtE plants today, is direct supply to nearby horticulture (greenhouses) as food-grade $CO_2$. For example, AVR and Twence in the Netherlands purify and liquefy flue-gas $CO_2$ and then transport it to nearby greenhouses. Reviews of WtE+CCU echo this pattern and highlight that Power-to-X (PtX) valorization of WtE $CO_2$ is still rare but emerging (Bertone et al., 2024). Christensen and Bisinella (2021) conclude in an extensive life cycle assessment (LCA) study that producing feedstock chemicals or fuels with $CO_2$ hydrogenation provides much higher benefits than direct utilization of captured $CO_2$ or CCS, but only in non-fossil-based energy systems, due to the dramatically high consumption of electricity. Several pioneering projects have already been implemented and demonstrate how $CO_2$ from waste incineration can be used in PtX applications. In Yokohama, Japan's first WtE-to-methanation pilot plant, $CO_2$ is captured from the Tsurumi WtE plant's flue gas and is converted into e-methane (Mitsubishi Heavy Industries, Ltd., 2023). In Finland, Vantaa Energy is developing a PtG facility that will capture $CO_2$ from its WtE plant and combine it with low-emissions hydrogen to synthesize e-methane (I.E.A. Bioenergy Task 44, 2025). In Dietikon (Switzerland), an award-winning industrial PtG plant produces around 18 GWh per year of synthetic methane via biological methanation, powered by electricity from the local WtE plant and using $CO_2$ from the wastewater treatment plant's digester gas (Limeco, 2024).

Several studies have mapped the technological and policy landscape for WtE-anchored carbon capture and PtM, but most evidence remains plant-centric or lacks high time resolution. Bertone et al. (2024) provide an extensive review of CCUS retrofits at WtE plants, covering incineration principles, capture routes, and regulation. They conclude that routing WtE plants $CO_2$ into PtX is still uncommon and that research has focused mainly on the technical and environmental sides of CCUS integration in WtE plants, with economics largely missing. In parallel, Ince et al. (2021) survey PtX modeling from 2015–2020 and document a steady rise in techno-economic analyses while confirming hydrogen production as persistent cost driver; within this literature, e-methane appears comparatively commercially-ready thanks to compatibility with existing gas infrastructure. At the process-plant scale, Salomone et al. (2023) study the integration of SNG production at a WtE plant, comparing capture technologies, electrolyzer types and heat-integration schemes and reporting energy and environmental indicators while missing the economic perspective.

Other studies on PtM outside the WtE context integrate the economic aspects but in plant-centric frames. As an example, Morgenthaler et al. (2020) used Calliope framework to optimize an hourly, fully renewable 100 kWe PtM island system and found levelized costs around 0.24–0.30 € $kWh^{-1}$; $CO_2$ is treated exogenously and carbon capture is not included. Likewise, Chauvy et al. (2020) couple cement plant $CO_2$ with wind-powered hydrogen in an Aspen flowsheet and report SNG costs around 115 €/MWh. Costs are dominated by high CAPEX costs of electrolyzers and renewable electricity prices. Earlier integrated work by Abdon et al. (2017) combines techno-economic analysis (TEA) and LCA across electrolyzer scales (tens of kW to GW), illustrating the centrality of scale and operating hours and how assumed $CO_2$ sourcing (e.g., DAC vs. biogenic streams) shifts outcomes.

At the system boundary scale, national and regional "potential" studies are informative about how much PtG might be feasible but stop short of economics or infrastructure. For Switzerland, Rüdisüli et al. (2023) estimate ≈ 7–20 $TWhyr^{-1}$ of PtG potential via geo-methanation by pairing surplus renewables with point-source $CO_2$, Run-of-River (RoR) and WtE nodes as promising anchors.

Taken together, the literature establishes the technologies, clarifies cost drivers, and quantifies single-site performance or national potential. What the literature does not yet provide is a regional, multi-node optimization that endogenizes transport infrastructure, inter-site resource sharing, hourly and seasonal demand profiles, and short- and inter-seasonal storage. The present study addresses this gap by optimizing the entire regional PtM system, capturing system-level interactions — such as the trade-off between pipeline investment and distributed methanation — that are invisible at single-plant scale.

## 2. Data and methodology

In the present study, regional SNG production for grid injection is evaluated and costs are reported as levelized cost of synthetic natural gas (LCOSNG, CHF/kWh), or as levelized cost of methane (LCOM, CHF/kWh) for cases that mix SNG production with natural gas (NG) imports. The system boundary includes $CO_2$ capture from waste incineration plants, hydrogen production via electrolysis, methanation, and — where relevant — transport and storage (pipelines and tanks) up to grid injection. Emissions accounting follows a Scope 2 approach: direct WtE stack emissions not captured are excluded; carbon intensity is applied to grid electricity, imported natural gas, and to any non-biogenic $CO_2$ used. Biogenic $CO_2$ used for SNG is treated as climate-neutral at point of use per the study's boundary choices.

### *2.1. Processes involved*

$CO_2$ is captured from the waste incinerator flue gas; $H_2$ is produced by electrolysis. Solid-oxide electrolysis (SOEC) are implemented at waste incineration plants to utilize available waste heat. SOEC are high-temperature electrolyzers that achieve higher electrical efficiency than low-temperature electrolyzers by utilizing heat to reduce the electrical energy required. Proton-exchange-membrane (PEM) electrolysis is considered at RoR hydropower sites for renewable $H_2$ production. Methane is produced by reacting captured $CO_2$ with $H_2$ in a catalytic methanation reactor following the Sabatier-reaction:

$$4\,H_2 + CO_2 \longrightarrow CH_4 + 2\,H_2O$$

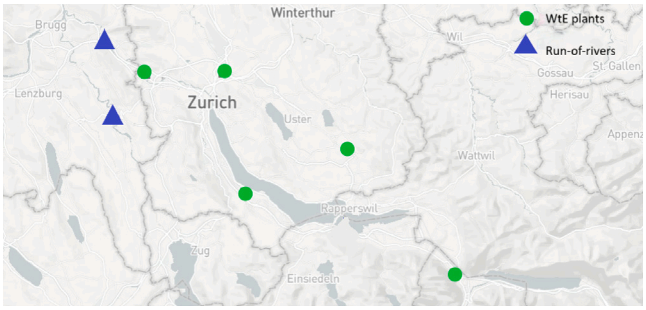



**Fig. 1.** Waste-to-Energy (WtE) plants and Run-of-Rivers (RoR) chosen in the area of operation of EnergiNova AG.

### 2.2. Region and sites selected

The study area is EnergiNova AG's territory, a main gas distributor around the Zurich lake. As shown in Fig. 1, the five WtE plants located in this area were selected: Hagenholz, Dietikon, Hinwil, Horgen and Linth. RoR within the area were assessed using the Confederation Geo data map. Two were selected (Bremgarten and Wettingen) based on their annual generation ($> 100\,\mathrm{GWh\,yr^{-1}}$). The PtM plants will be located at the WtE plants, where the SNG will be directly injected into the gas grid. The RoR will serve as additional hydrogen production sites.

### 2.3. Cases and scenarios modeled

Three cases that differ in electricity source, import options, and policy signals are studied. Each case has subcases which are referred to as scenarios.

- *Case 1: SNG production from grid electricity* assesses the regional PtM potential with no constraint on the electricity side. Indeed, electricity for the SOEC is drawn from the grid, transport of $CO_2$ and $H_2$ by pipelines between the WtE plants is available. To always match the demand, natural gas import is also available but at an expensive exaggerated price, so the model chooses to import only as last resort. This first case gives a sense of how the production could look like and the total costs of such a system. Two scenarios will be envisioned: one with the current demand of gas and one with the 2050 estimated future demand. Fig. 2 shows how the system can look like at each waste incineration plant. The $CO_2$ in the flue gas, which is normally emitted, is captured by the CC. The SOEC is fueled by waste heat from the incineration process and grid electricity. The $CO_2$ and $H_2$ are then combined in a methanation reactor and the SNG produced is fed into the natural gas grid. Note that some imports within the region are allowed, $CO_2$ and $H_2$ can be transported from one WtE plant to another via pipelines.
- *Case 2: Renewable SNG production and $H_2$ import* is a fully renewable SNG case. Hydrogen is either produced locally using renewables or imported through the EHB as low-emissions hydrogen. Local electricity is supplied by photovoltaics installed on municipal rooftops in the WtE plant's municipality and by two selected RoR. The hydrogen from the RoR is transported by pipelines to the waste incineration plant. A utility battery, hydrogen and LNG storage are made available. Hydrogen can be temporarily stored in compressed form to buffer the operation between the electrolyzer and the methanation reactor. When SNG production exceeds the instantaneous gas demand, the surplus methane is liquefied and stored as LNG, which enables compact, high-density storage suitable for the large seasonal volumes considered. Current demand is not simulated for this case because the EHB is assumed operational only from 2030 onwards, which aligns with the 2050 horizon.
- *Case 3: Renewable SNG production and natural gas import* also produces hydrogen locally using renewables but allows for natural gas imports instead of hydrogen (in contrast to Case 2). Different scenarios are simulated with each a different $CO_2$ tax level applied on the natural gas import of 120/480/1970 CHF $t^{-1}$ to probe policy effects.

### 2.4. Data and profiles

Resources and demand are given as an hourly profile over a year.

#### 2.4.1. Natural gas demand

A "Current demand profile" has been calculated using the mean of 2013–2023 EnergiNova data (outliers removed), totaling $\sim 3.2$ TWh $\mathrm{yr}^{-1}$. The "2050 profile" is constructed with a baseload equal to 40% of summer load plus 30% retention of current winter heating demand, totaling $\sim 1.2$ TWh $\mathrm{yr}^{-1}$.

#### 2.4.2. WtE plants data

$CO_2$ emissions and waste heat availability at waste incineration plants were first found by year and then downscaled to an hourly profile taking as a basis Horgen's WtE plant 2022 profiles. Annual $CO_2$ is estimated as 1 t $CO_2$ per 1 t waste incinerated, then downscaled to hourly using Horgen's flue-gas and $CO_2$ content profiles. Heat surplus profiles are built analogously from Horgen data (waste-to-heat yield, losses, own-use). Detailed information can be found in Supplementary data, Appendix C.

#### 2.4.3. Renewables and site resources

The PV potential has been estimated taking all the roofs available at the municipality where the WtE plant is located. Crystalline silicon photovoltaic modules are considered with a module efficiency of 20%. The hourly PV power generation for a 1 kWp module for year 2023 has been found using PVgis tool database PVGIS-Sarah (European Commission – Joint Research Centre, 2025), at the different locations. We assume that the irradiation should not vary much between locations and an average has been taken to speed up the simulations. A default system loss of 14% was assumed, the slope and azimuth were optimized by the tool itself.

The maximum surplus power that can be used from the two RoR was estimated by subtracting the current generation from the maximum power that can be produced by the turbines. Data about the turbines' power and the yearly generation was found in the "Statistics on hydropower plants" (WASTA). Then, assuming that the monthly production should be similar to the national one, a monthly profile was derived using the 2024 RoR monthly production in Switzerland. From there, an hourly generation profile was derived assuming that the hourly production is constant over a month. The surplus is especially high during spring and summer. This monthly disaggregation of RoR generation, combined with the assumption of constant hourly production within a month, represents an upper bound on surplus electricity availability.

#### 2.4.4. Economic and emission parameters

Global parameters related to technologies are presented in the table below. The electricity cost of 0.19 CHF/kWh corresponds to the Swiss C7 industrial tariff (> 7.5 GWh/yr), which is a contracted rate and therefore less volatile than wholesale spot prices.

The technologies have been specified in the model using multiple parameters:

- Efficiency
- Energy capacity range: Maximum and minimum in [kW] or [kg/h]
- Storage capacity range: Maximum and minimum in [kWh] or [kg]
- Carrier ratios between the input and output

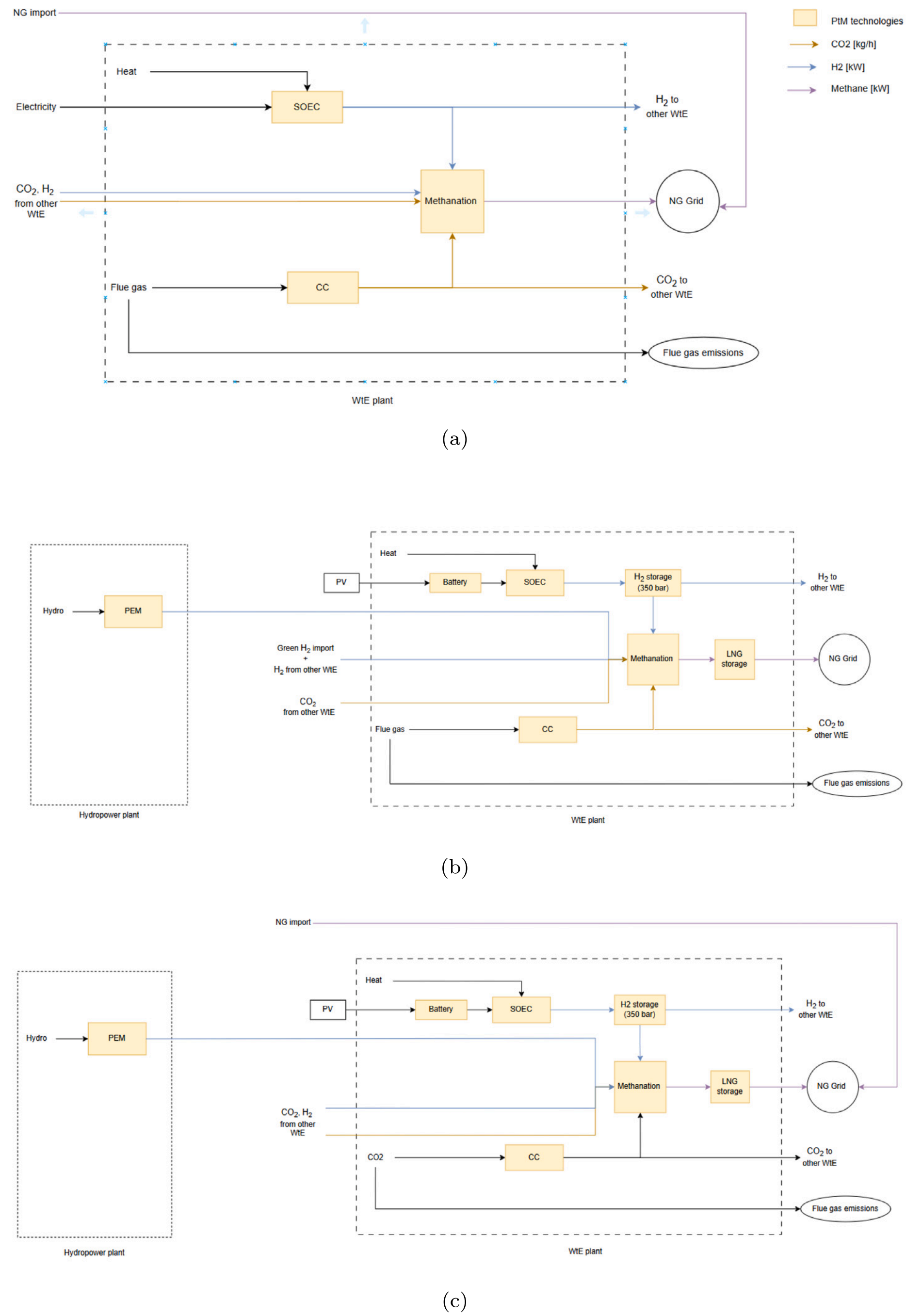



**Fig. 2.** Process diagrams showcasing the configurations and technologies available for the three cases. PEM = proton exchange membrane, PV = solar photovoltaic, CC = carbon capture, SOEC = solid oxide electrolyzer cell, NG = natural gas, WtE = Waste-to-Energy plants. (a) Case 1: SNG production from grid electricity. (b) Case 2: Renewable SNG production and $H_2$ import. (c) Case 3: Renewable SNG production and natural gas import.

- Lifetime

The energy and storage capacities of the technologies are consistently associated with the output carrier. All conversion calculations in the system have been based on the HHV. The specific data used in the model by technology has been summarized in tables displayed in Supplementary Material, Appendix A.

LNG storage per KVA is restricted to the medium-size class (77 GWh = 12,300 m3 at 6.25 kWh/L HHV, corresponding to a cylindrical tank of roughly 28 m diameter and 20 m height), reflecting the footprint, safety-zoning, and permitting constraints of urban waste-incineration plots. Larger regional-terminal-scale tanks (100,000 m3) are considered infeasible at these sites and therefore excluded.

### *2.4.5. Investment costs calculation*

Costs are taken for year 2023. When the costs found were from previous years, the CEPCI (Chemical Plant Cost Indexes) was applied using the following formula:

$$C_{\text{inv}}^{\text{year2022}} = C_{\text{inv}}^{i} \cdot \frac{\text{CEPCI}^{2022}}{\text{CEPCI}^{i}}$$

The capital costs associated with the initial expenses are generally not linear. Thus, they had to be linearized using a linear approximating function by choosing a specific point (technology size) and size range, giving the following linear cost function:

$$C(x) = C_{\text{inv,fix}} + C_{\text{inv,var}} \cdot x, \quad x_{\min} \leq x \leq x_{\max}$$

**Table 1**
General parameters used in the simulation.

| Parameter | Value | Comment |
|---|---|---|
| Interest rate $i$ | 5% | Interest rate |
| Electricity cost [CHF/kWh] | 0.19 | C7 category (7 500 000 kWh/yr and 1630 kW maximum power) (ElCom, 2023) |
| $H_2$ import cost [CHF/kWh] | 0.079 | $H_2$ import via pipeline from North Africa (International Energy Agency (IEA), 2023) |
| Natural gas import cost [CHF/kWh] | 0.50 | Although the current cost is much lower, this one was agreed upon after discussions with EnergiNova. |
| Exchange rate USD/CHF | 0.89 | Average on year 2023 |
| Exchange rate EUR/CHF | 1 | Assumption due to typically low difference |
| $E_G$ [kg $CO_2$-eq/kWh] | 0.089 | Electricity consumption carbon intensity (Rüdisüli et al., 2022) |
| $NG_G$ [kg $CO_2$-eq/kWh] | 0.228 | Natural gas production and transport to Switzerland (WWF, 2025) |
| $CO_2$ tax [CHF/t $CO_2$] | 120 | $CO_2$ tax in Switzerland (FOEN, Federal Office for the Environment, 2025) |

In case different range sizes are defined for a technology, piecewise linearization has been used, allowing to have a continuous function made of linear segments on each interval defining the technology size range.

### 2.4.6. Modeling approach

The problem is translated into a mathematical optimization problem, specifically into a MILP, formulated in `Calliope v0.6.10` and solved with `Gurobi v10.0.0` on a one-year, hourly horizon. Nodes represent WtE and RoR sites; links represent pipelines. The solver selects which technologies to install, their sizes, and hourly dispatch to minimize total annualized system cost subject to balances and limits. Decision variables in the model include power generation levels, technologies purchase, size and location, energy storage operation, carriers imported and exported, and dispatch schedules. Constraints represent the technical, environmental, and operational limitations and relationships within the energy system, ensuring that the model solution adheres to specified requirements, such as energy balance equations and demand/supply constraints.

The objective minimizes total annualized cost:

$$\min z$$

$$z = \sum_{l \in L} \sum_{t \in T} C_{l,t}$$

$$C_{l,t} = C_{\text{inv},l,t} + \sum_{\tau \in \text{time}} C_{\text{var},l,t,\tau}$$

The cost function is composed of two components, the annual investment costs and the variable costs. The annual investment costs encompass the capital costs and the maintenance costs. The variable costs are time dependent and encompass the carriers consumption and production price (if specified) over one year. To get the investment costs in [CHF/year], the annualization is done as follows:

$$C_{\text{inv},l,t} = C_{\text{inv,tot},l,t} \cdot \frac{i(1+i)^n}{(1+i)^n - 1}$$

where:

- $C_{l,t}$: Annual cost of technology $t$ at location $l$.
- $C^{\text{inv}}_{l,t,k}$: Annual investment cost of technology $t$ at location $l$.
- $C^{\text{var}}_{l,t,k,\tau}$: Variable cost of technology $t$ at location $l$ at time $\tau$.
- $C_{\text{inv,tot},l,t,k}$ are the total investment costs in CHF
- $n$ is the lifetime of each technology considered
- $i$ is the interest rate

Let $l \in L$, $t \in T$, $c \in C$, and $\tau \in$ time, such that:

- $L$: Set of locations
- $T$: Set of technologies $\{T_{\text{prod}}, T_{\text{supply}}, \dots\}$
- $C$: Set of carriers
- time: Set of timesteps

For reporting, two cost metrics are used. The levelized cost of methane (LCOM) is the ratio of annualized investment and fixed and variable operation-and-maintenance costs to the total methane delivered to the grid, including imports. The levelized cost of SNG (LCOSNG) is calculated over only the locally produced SNG volume and is undefined when no SNG is produced. LCOM is the primary economic indicator; LCOSNG is used when it is informative to separate the cost of local production from that of imports.

### 2.4.7. Assumptions

Waste-heat is shared by district heating, on-site uses, capture, and SOEC, therefore, there might be a competition between the different end-uses. The surplus heat (Waste-heat minus district heating, own consumption and power delivered) and $CO_2$ emissions calculated do not match at every timestep. Therefore, we do not force carbon capture to match total emissions. Capture is sized and dispatched to support PtM.

The carbon footprint is accounted using Scope 2 and is applied for the electrical grid, natural gas import and on the non-biogenic $CO_2$ that might be as well captured and used for SNG production. In Switzerland, half of the carbon dioxide emitted by waste incineration plants is considered biogenic (Mohn et al., 2012), (Jorio, 2020). Moreover, the electricity emissions in Switzerland are of only 33 g/kWh when only accounting for the emissions due to production (Energyscope, 2024). This value is actually much higher when accounting for the imports and is then equal to 89 g/kWh (Rüdisüli et al., 2022). Direct WtE stack emissions are excluded as they occur independently of PtM operation. Combustion of SNG produced from biogenic $CO_2$ is treated as climate-neutral. Potential direct (Scope 1) emissions from the PtM process chain — including fugitive methane leakage from pipelines and storage, and $CO_2$ venting from capture units — are not explicitly modeled. This is consistent with the treatment in the EU Renewable Energy Directive (RED II), where such process emissions for Power-to-X pathways were assessed as negligible (Bube et al., 2025). Robust empirical data on Scope 1 emissions from PtM systems at scale are not yet available, as no large-scale regional PtM network is currently in operation. Gray emissions from equipment manufacturing and construction are excluded and would require a full life cycle assessment.

**Table 2**
Key results for Case 1: SNG production from grid electricity.

| | Current demand | Future demand |
|---|---|---|
| LCOM [CHF/kWh] | 0.44 | 0.42 |
| LCOSNG [CHF/kWh] | 0.34 | 0.38 |
| Annualized costs [MCHF/yr] | 1414 | 525 |
| CAPEX [MCHF/yr] | 107 | 96 |
| SNG production [GWh/yr] | 1291 | 764 |
| $CO_2$ utilization[a] | 0.36 | 0.24 |
| Heat utilization[a] | 0.54 | 0.32 |
| Emissions reduction vs Base | 0.23 | 0.41 |

[a] Fraction of available resource used for SNG production.

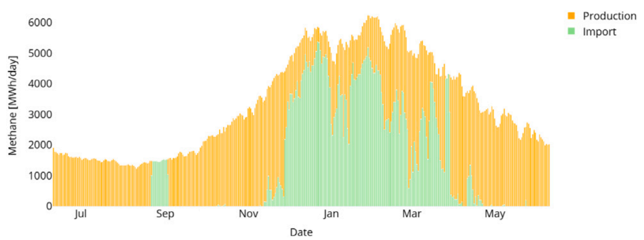
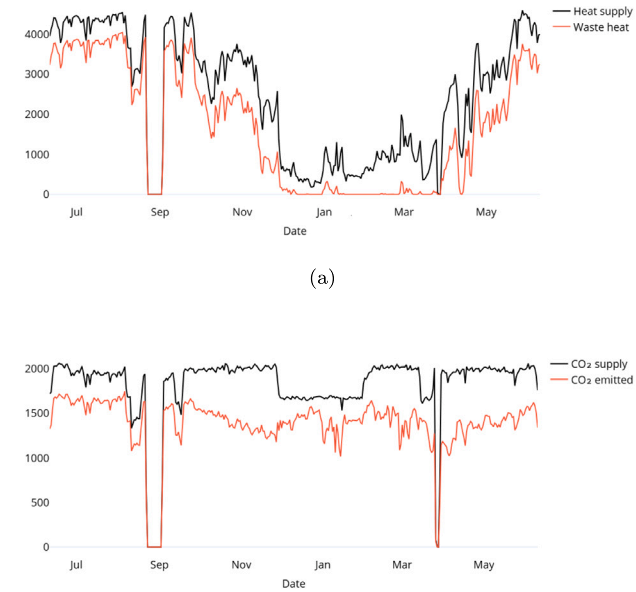



**Fig. 3.** Case 1 *Future demand*: SNG production and natural gas imports in MWh/day.




(a)

(b)

**Fig. 4.** Case 1 *Future demand*: Aggregation of resources availability at all WtE plants (black lines) and residual quantities after utilization for SNG production (red lines). (a) Heat in MWh/day. (b) $CO_2$ in t/day.

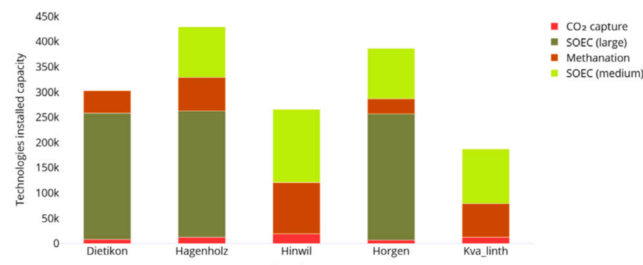



**Fig. 5.** Case 1 *Future demand*: Units installed with their respective capacities for each location. Energy capacity has a different unit depending on the carrier. For methanation it is in kW of methane produced, for the $CO_2$ capture it is in kg/h of CO2, for the SOEC it is in kW.

Inter-unit compression between capture and methanation ($CO_2$) and SOEC and methanation ($H_2$) is neglected due to low pressure difference. For transport and storage, compression investment costs are included but not operational costs due to model limitations. Specific compression energy is calculated post-simulation for sensitivity.

## 3. Results

### 3.1. Case 1: SNG production from grid electricity

The key outcomes for both scenarios (*Current demand* and *Future demand* (estimated for 2050)) are summarized in Table 2. In both cases, the LCOM (local SNG + NG imports, computed at the assumed NG price of 0.50 CHF/kWh per Table 1) is high, and despite the deliberately inflated cost of methane imports, the model still opts for substantial imports (≈ 60% of demand today and ≈ 38% in 2050).

Seasonal variations are evident in the simulated SNG production (Fig. 3). Production peaks in summer, spring, and early autumn, while winter demand is largely met by natural gas imports. The two-week dip in August reflects maintenance downtime at the Horgen WtE plant, from which all time-profiles were derived. The seasonal trend is governed by resource availability: in summer and spring, abundant heat supports hydrogen production, whereas in winter, most heat is redirected to district heating, limiting SNG production (Fig. 4(a)). However, enough $CO_2$ is available throughout the year independently of the season (Fig. 4(b)).

In both scenarios, PtM technologies are deployed at all five waste incineration plants with the same configuration. Fig. 5 shows the technologies installed in the *Future demand* scenario, which results in slightly smaller average unit sizes, reflecting lower overall SNG production but still requiring peak-shaving capacity (Fig. 5). For both scenarios, the cost-optimal configuration combines distributed SOEC capacity totaling around 1.20 GW across the five plants, with a mesh of $H_2$ transfer pipelines linking the five WtE plants of combined flow capacity of 1.2 GW. $CO_2$ pipelines are not constructed.

Cost structures are dominated by NG imports: 69% and 44% of total costs for *current demand* and *future demand* respectively. When considering solely the SNG production costs (Fig. 6(a))), electricity purchases for electrolysis represent the largest share and account for most of the cost difference between the two scenarios. Annualized CAPEX amounts to 107 MCHF/yr for *current demand* and 96 MCHF/yr for *future demand*, reflecting the smaller installed capacities in the latter scenario. In both scenarios, the CAPEX distribution follows the same pattern: approximately 50% for $H_2$ pipelines, 33% for electrolysers, 13% for methanation, and 4% for $CO_2$ capture. Interestingly, the LCOSNG is lower for the *Current demand* scenario due to economies of scale — higher production spreads the fixed costs over more delivered methane.

Fig. 6(b) compares emissions to a "Base" case in which demand is met exclusively by natural gas imports (280 kt $CO_2$/yr). Emissions in the PtM scenarios include those from natural gas imports (transport and combustion) and electricity footprint for hydrogen production. Since half of waste incineration plants emitted $CO_2$ is biogenic (see Section 2.4.7) and less than 50% of total emissions are captured, the captured fraction is attributed to the biogenic pool; combustion of SNG is therefore treated as climate-neutral and not accounted for. Relative to the Base case, emissions decrease by 23% for *Current demand* and 41% for *Future demand*, underlining the mitigation potential of PtM even when relying on grid electricity, whose carbon footprint (89 g $CO_2$-eq/kWh, see 1) limits further reductions.

Finally, the impact of compression costs was assessed separately. Since no $CO_2$ pipelines are installed, only $H_2$ compression is relevant. The required compression work amounts to around 43 GWh/yr

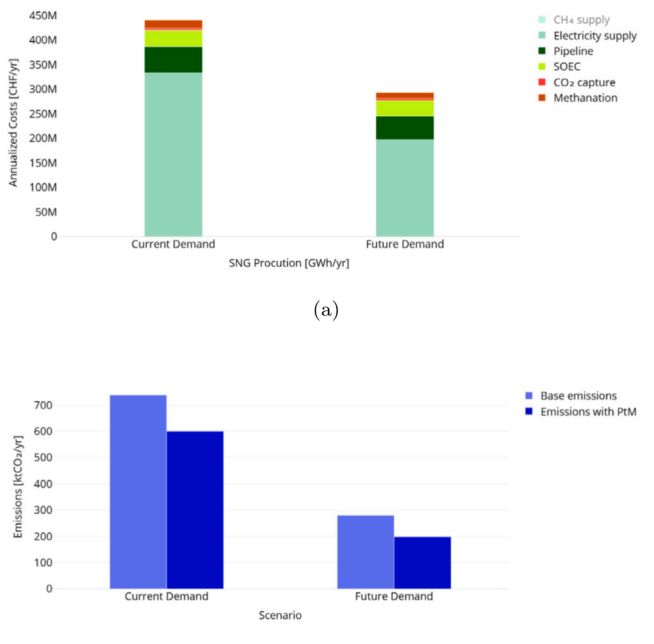



**Fig. 6.** Case 1: SNG annualized costs and total emissions comparison for both scenarios. The scenario's emissions (Emissions with PtM) are relative to the baselines emissions from full natural gas imports (Base emissions).

**Table 3**
Key results for Case 2: Renewable SNG production and low-emissions $H_2$ import.

| | Future demand |
|---|---|
| LCOM [CHF/kWh] | 0.16 |
| Annualized costs [MCHF/yr] | 214 |
| CAPEX [MCHF/yr] | 100 |
| SNG production [GWh/yr] | 1227 |
| $CO_2$ utilization[a] | 0.34 |
| Heat utilization[a] | 0.16 |
| $H_2$ production share[b] | 0.17 |
| Emissions reduction vs Base | 1 |

[a] Fraction of available resource used for SNG production.
[b] Share of total $H_2$ demand produced locally (remainder imported).

which, at an electricity price of 0.19 CHF/kWh, corresponds to about 8 MCHF/yr, and is therefore minor compared to total system costs. However, compression increases pipeline CAPEX by 10%.

### 3.2. Case 2: Renewable SNG production and low-emissions $H_2$ import

Case 2 explores a fully renewable hydrogen pathway, where low-emission hydrogen import is allowed to ensure feasibility and to benchmark local production against imports. Only the 2050 demand is simulated, as such imports via pipeline are not currently possible. Carbon dioxide import is permitted to ensure feasibility but penalized with a very high price, encouraging maximum use of $CO_2$ from the WtE.

Key results are summarized in Table 3. The LCOM, which is here the same as the LCOSNG, is 0.16 CHF/kWh. 34% of the available $CO_2$ and 16% of the heat are used in the conversion chain. Local hydrogen production accounts for 17% of supply, with the remainder covered by imports.

Under this low-emissions hydrogen pathway, the optimal architecture shifts from "distributed electrolysis" to "concentrated electrolysis with distributed methanation" (Fig. 7(a)). Methanation is deployed

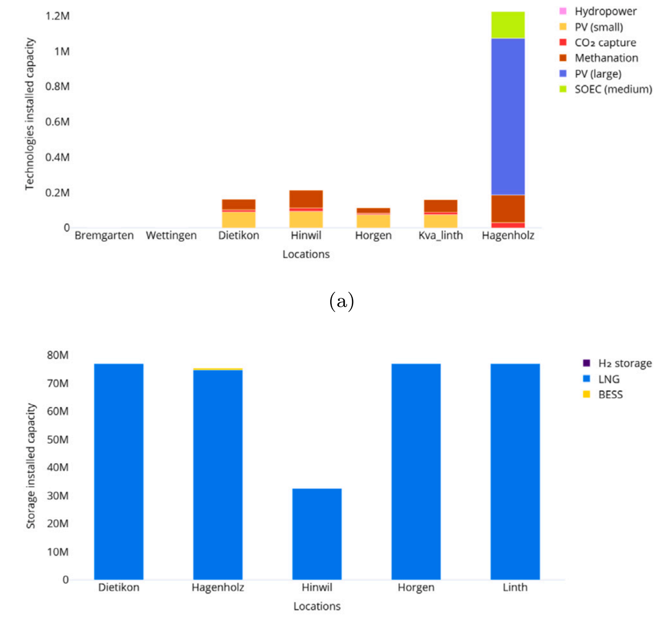
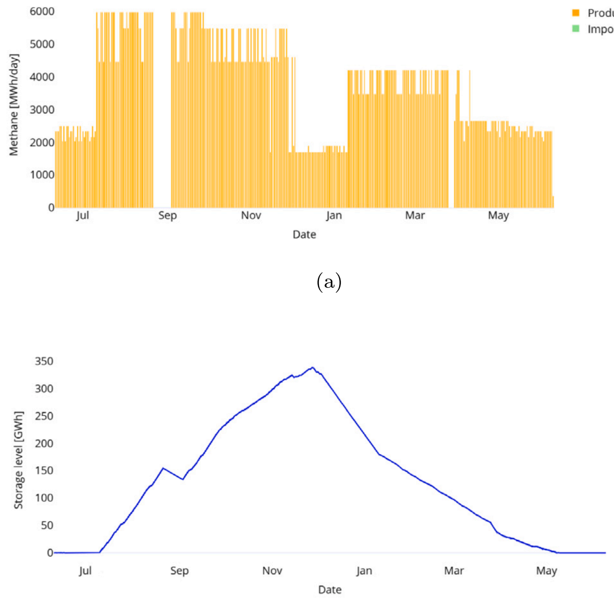



**Fig. 7.** Case 2: Installed technologies and storage capacities by location. Energy capacity has a different unit depending on the carrier. For methanation it is in kW of methane produced, for the $CO_2$ capture it is in kg/h of $CO_2$, for the SOEC it is in kW of $H_2$ produced. Storage capacity is in kWh. PV = solar photovoltaic, SOEC = solid oxide electrolyzer cell, LNG = liquified natural gas, BESS = utility-scale batteries.

at all five WtE plants (32–157 MW capacity, matched to local captured $CO_2$). RoR locations do not produce hydrogen. $H_2$ production takes place exclusively at Hagenholz (151 MW SOEC), where a high-temperature electrolyzer couples the largest local PV potential with the plant's waste heat, yielding higher electrolyzer efficiency than the PEM option available at the RoR sites. The bulk of $H_2$ feed ($\approx$ 83% of methanation requirements) is met by pipeline import from the European Hydrogen Backbone at an assumed price of 0.079 CHF/kWh, not by local production. Therefore, no inter-site $H_2$ pipelines are deployed because each waste incineration plant draws imported $H_2$ from the EHB. Methanation remains fully decentralized for the same cost reason as in Case 1: $CO_2$ pipeline CAPEX per kW of delivered energy is roughly 13 times that of $H_2$ pipelines, so methanation stays at the $CO_2$ source. A large deployment of LNG storage at all locations (maximum storage size of 77 GWh at Dietikon, Horgen and Linth) is observed, totaling 338 GWh. Battery energy capacity is modest (0.6 GWh, at Hagenholz only), but its CAPEX share is large (47%) because of the high per-kWh cost of utility batteries, while LNG tanks provide the seasonal balancing and reshape the production profile (Fig. 7(b)). Methanation activity is shifted toward summer and spring when renewable electricity is abundant, while winter demand is largely met by stored methane (Fig. 8).

Total costs (214 MCHF/yr) are dominated by OPEX with the hydrogen import costs. CAPEX (100 M CHF/yr) is dominated by on-site renewables and storage (PV 24%, utility-scale battery 47%) that supply electrolyzer and other loads; the PtM technologies account for the remaining 29%.

The impact of LNG compression was assessed separately. Around 500 GWh of methane are stored annually, requiring $\approx$ 16 GWh/yr of compression work. At an electricity price of 0.19 CHF/kWh, this corresponds to $\approx$ 3 MCHF/yr. Compared with the total annualized system cost of 214 MCHF/yr, the effect is marginal ($<$ 2%).




(a)

(b)

**Fig. 8.** Case 2: SNG production. The 2-weeks gap observed in August is due to maintenance of waste incineration plants. (a) and LNG storage level (b) profile throughout the year.

**Table 4**
Key results for Case 3: SNG production with natural gas import, for three $CO_2$ tax levels applied to the imported $CH_4$.

| | Scenario a | Scenario b | Scenario c |
|---|---|---|---|
| $CO_2$ tax [CHF/t $CO_2$] | 120 | 480 | 1970 |
| LCOM [CHF/kWh] | 0.08 | 0.15 | 0.39 |
| LCOSNG [CHF/kWh] | 0.00 | 0.11 | 0.15 |
| Annualized costs [MCHF/yr] | 96 | 201 | 483 |
| CAPEX [MCHF/yr] | 0.5 | 35 | 60 |
| SNG production [GWh/yr] | 0 | 314 | 405 |
| $CO_2$ utilization[a] | 0.00 | 0.09 | 0.12 |
| Heat used utilization[a] | 0.00 | 0.10 | 0.13 |
| Emissions reduction vs a | – | 0.42 | 0.64 |

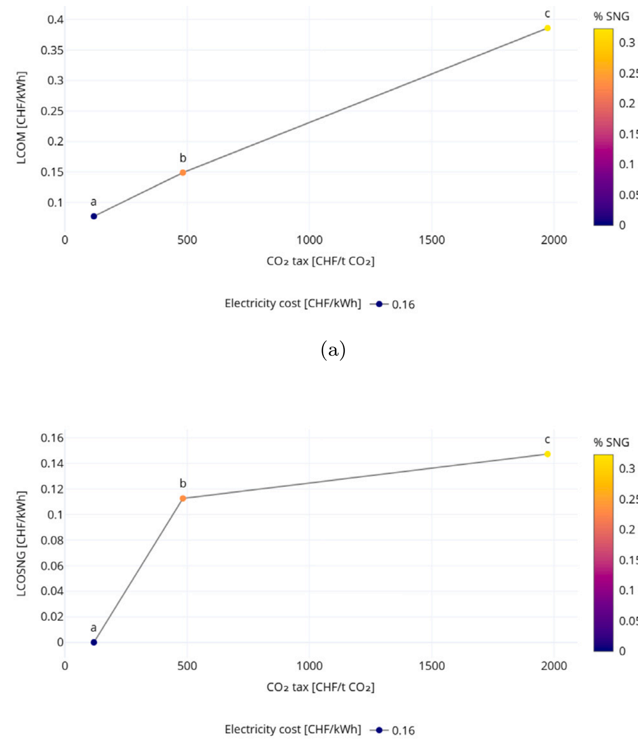
[a] Fraction of available resource used for SNG production.

### 3.3. Case 3: Renewable SNG production and natural gas import

In case 3, in addition to local SNG production, the import of natural gas is permitted. A $CO_2$ levy (carbon tax) is applied to methane imports, and its value is varied to assess the impact on overall costs, emissions, and SNG production. While the base cost of natural gas remains constant, the total import cost increases with the $CO_2$ tax, ranging from the current level up to an extreme value of nearly 2000 CHF/t $CO_2$. Table 4 summarizes the results for the three modeled scenarios.

As illustrated in Fig. 9(a), an increasing $CO_2$ tax leads to higher LCOM (local SNG + NG imports) and greater SNG production, thereby reducing total emissions and driving the system toward higher self-sufficiency. Under *Scenario a*, which applies the current tax of 120 CHF /t $CO_2$, all methane is imported, as SNG production is not economically viable. In *Scenario b*, where the current tax is quadrupled, while the total costs are doubled, the LCOM is 0.15 CHF/kWh and the emissions are reduced by 42%. In *Scenario c*, emissions are further reduced (64% compared to *Scenario a*) but the resulting LCOM of 0.39 CHF/kWh is prohibitively high.

When considering only the SNG contribution (excluding imports; Fig. 9(b)), *Scenario b* supplies 23% of demand, whereas *Scenario c* covers 32%. A balance between acceptable cost, emission reduction and self-sufficiency must therefore be identified.




(a)

(b)

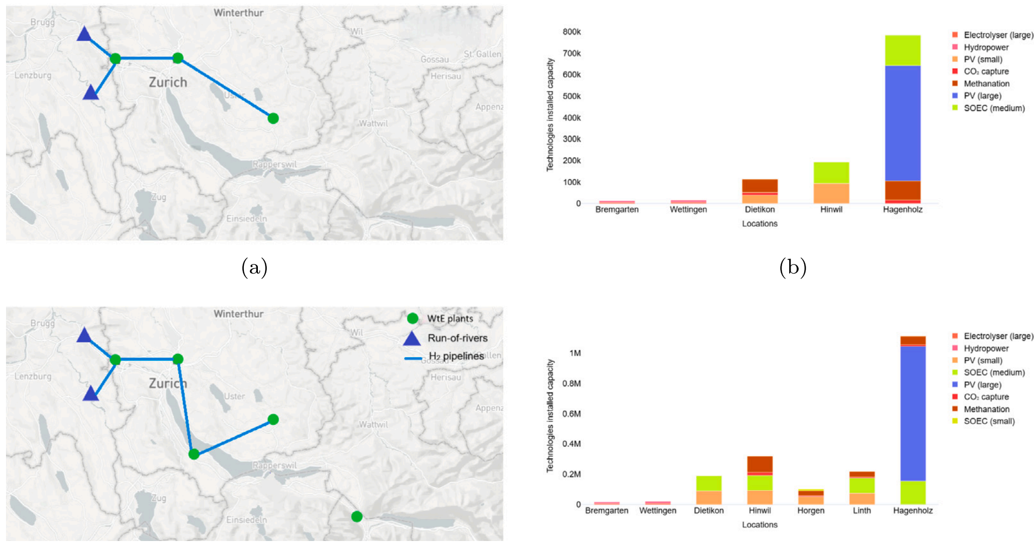
**Fig. 9.** Levelized Cost of Methane (LCOM) (a) and Levelized Cost of SNG (LCOSNG) (b) as a function of $CO_2$ tax. The color bar illustrates the share of total methane demand met by SNG.

The incremental cost of emission abatement rises sharply between the two SNG scenarios: *Scenario a* to *b* delivers a 42 percentage-point emission reduction for an LCOM increase of roughly 0.07 CHF/kWh, whereas *b* to *c* adds a further 22 percentage points at an incremental cost of about 0.24 CHF/kWh. *Scenario b* therefore emerges as a more cost-effective operating point, while *Scenario c* represents a boundary case illustrating the maximum emission reduction achievable within the available renewable resources under extreme carbon pricing.

Fig. 10 shows the configuration of SNG production and the units installed for both scenarios *b* and *c*. In *Scenario b*, SNG production occurs at Hagenholz and Dietikon (89 and 62 MW of methanation, respectively). Hagenholz hosts both hydrogen (141 MW SOEC) and methane production, while Dietikon focuses solely on methane. Surplus $H_2$ is generated at nearby facilities – 100 MW of SOEC at Hinwil and ≈12 MW of PEM electrolysis at the two RoR power plants – and distributed to Hagenholz and Dietikon via pipelines. In *Scenario c*, two additional sites, Horgen and Linth waste incineration plants, are integrated into the SNG network, raising total methanation capacity from ≈150 to ≈230 MW. All the WtE plants produce SNG except Dietikon, which hosts PV installations and a 100 MW SOEC to produce $H_2$ for delivery to other sites. Total SOEC capacity reaches 466 MW, supplemented by ≈16 MW of PEM at the RoR nodes. In general, technology sizes increase with SNG capacity.

The total LNG storage size remains constant at 39 GWh. In *Scenario c*, limited $H_2$ storage is added, while no batteries are installed in either scenario. Only low pressure $H_2$ pipelines are constructed. Large-scale compressed $H_2$ pipelines are not implemented due to their higher cost. Instead of increasing pipeline capacity to reduce methanation reactor costs at a given location, it appears more cost-effective to install additional methanation units.

CAPEX is effectively zero in *Scenario a* (no PtM deployed) and rises to 35 MCHF/yr in *Scenario b* and 60 MCHF/yr in *Scenario c*. In




(a) (b)

(c) (d)

**Fig. 10.** Spatial distribution of SNG production sites and hydrogen transport network for *Scenario b* (a, b) and *Scenario c* (c, d).

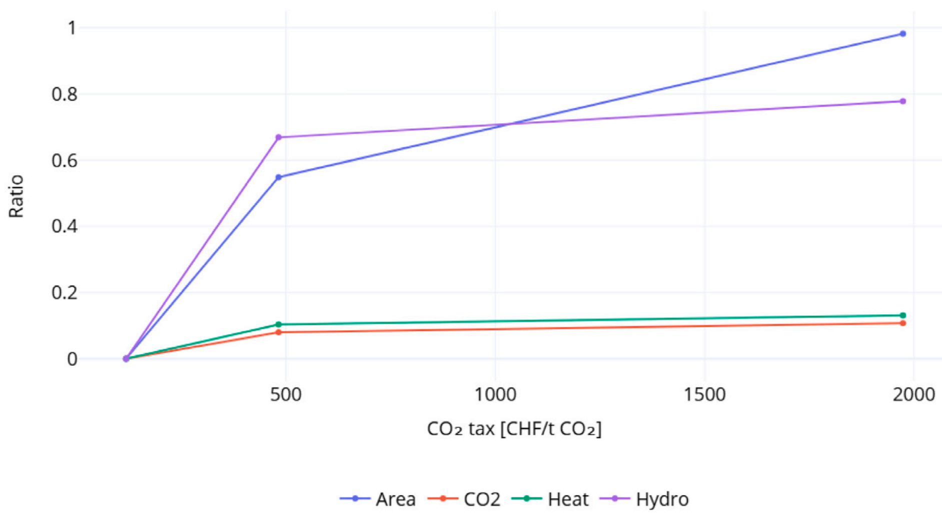



**Fig. 11.** Ratio of resources used as a function of applied $CO_2$ tax.

both SNG-active scenarios, CAPEX is dominated by PV (≈40%) and electrolysers (29–32%); methanation contributes 15–17%, $CO_2$ capture 4–5%, and $H_2$ pipelines only 4–5% because the active subset of sites is small and the pipeline network is short. No $CO_2$ pipelines are installed.

Renewable electricity capacity remains the main limiting factor for SNG production, as observed in the previous cases. Fig. 11 shows that at the highest $CO_2$ tax, the entire PV area available is utilized, and 78% of the river power plant capacity is used for $H_2$ production. With the current $CO_2$ tax (*Scenario a*), the model chooses to import $CH_4$ exclusively because building PtG units is not economically viable. Consequently, the LCOM reaches only 0.077 CHF/kWh, but annual emissions amount to 283 kt $CO_2$. Increasing the tax encourages more SNG production until the renewable potential is fully exploited.

### 3.4. Sensitivity analysis

The sensitivity of the system to key parameters is analyzed for the different cases. Only most uncertain parameters are selected: grid electricity price, hydrogen import cost through the EHB, $CO_2$ pipeline costs and methane demand projection for 2050. For NG import, the assumed import price of 0.50 CHF/kWh is conservative (above current levels), no sensitivity analysis is required. Lower prices would only reinforce the finding that SNG requires policy support. No CAPEX sensitivity is performed as capital expenditure represents less than 25% of total annualized cost in all cases, so even substantial CAPEX variations would not shift the costs as much as the OPEX. A summary of all sensitivity results can be found at the end of the Section in Table 5.

*Electricity price (Case 1 future demand).* The effect of electricity cost is investigated in Case 1 by varying the cost by ±40%. The results show that, for both higher and lower electricity costs, the annual production of SNG remains constant at 764 GWh/year. This indicates that SNG production is not limited by electricity cost and operates near its maximum potential, given the constraints of heat availability during winter and the installed technologies. The SNG share could be further increased by adding LNG storage, as observed in Case 2. Overall, system costs change by ±10%, with an LCOM of 0.38 CHF/kWh for lower electricity prices and 0.48 CHF/kWh for higher prices. Additionally, higher electricity costs lead to the construction of fewer $H_2$ pipelines.

*$CO_2$ pipeline cost (Case 2).* Across all base cases described in the previous sections, no $CO_2$ pipelines are built. This could be due to their

costs, which is usually higher than hydrogen especially the CAPEX of compression. This hypothesis is tested by reducing $CO_2$ pipeline costs to 60%, 40% and 25% of the reference value (1406 CHF/kW and 891 CHF/km). The LCOM remains within ±1.2% of the reference across the entire range, confirming that the system economics are insensitive to the $CO_2$ pipeline unit cost.

The optimizer selects two distinct configurations depending on the cost level. At the reference and at the strongest reduction (25%), no $CO_2$ pipeline and no $H_2$ pipeline are built; methane is produced from imported $H_2$ combined with on-site $CO_2$ capture, with local electrolysis covering 17%–18% of the $H_2$ demand. At intermediate cost reduction (60–40%), the optimizer instead invests in 136 km of $CO_2$ pipelines, centered at Hagenholz, supplying $CO_2$ to all other methanation sites; together with a small $H_2$ pipeline backbone of 29 km. Despite these pipelines, the system is still decentralized, with $CO_2$ capture units installed at all locations and electrolysis built at multiple locations instead of only Hagenholz (base case). In this mixed configuration the local $H_2$ share rises to 26–28%, reflecting the additional load taken by the electrolysis.

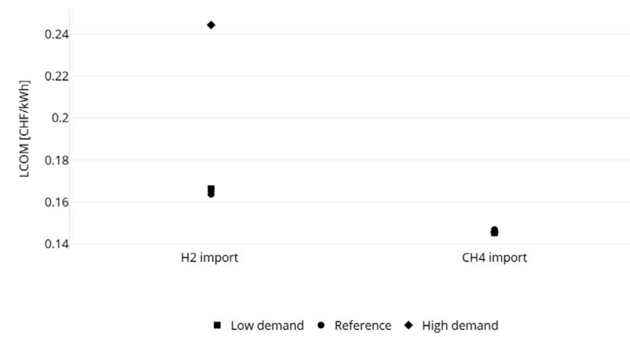
Because both configurations yield comparable LCOM, the choice between them is not strictly monotonic in $CO_2$ pipeline cost. The practical conclusion is that $CO_2$ pipeline CAPEX uncertainty does not threaten the LCOM result, and that even sizeable reductions in $CO_2$ transport cost are insufficient to unlock a clearly preferred system architecture.

*Hydrogen import price (Case 2).* The $H_2$ import price was varied by ±40% around its reference value of 0.079 CHF/kWh, yielding a high case at 0.111 CHF/kWh and a low case at 0.047 CHF/kWh. LCOM responds strongly and almost symmetrically: a ±40% change in $H_2$ import price drives a ±20% change in LCOM, confirming that imported $H_2$ is the dominant LCOM driver and contributes to roughly half of the methane production cost across the explored range. The system architecture responds differently in the two directions. At the higher price, the configuration matches the reference case: no $CO_2$ or $H_2$ pipelines are built, and the local $H_2$ share rises only slightly, from 16.9% to 18.5%. At the lower price, the optimizer builds a 101 km $CO_2$ pipeline backbone centered at Hagenholz, a 29 km $H_2$ pipeline backbone, and the local $H_2$ share rises to 23.5%. The $H_2$ import price is therefore the main lever on LCOM, much more than $CO_2$ pipeline CAPEX.

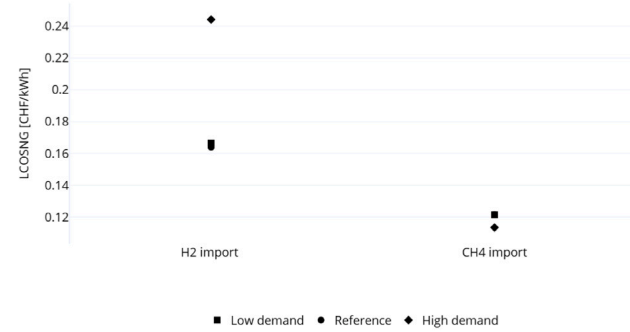
*Demand (Cases 2 and Case 3 scenario b).* One of the key uncertainties in the model is the future demand, which directly influences both the volume of imports and local production. Cases 2 and Case 3 *Scenario b* (renewable SNG production combined with natural gas imports) are selected as they both result in acceptable costs and local SNG production. Fig. 12 shows the impact of demand variation (±30% from reference) on LCOM and LCOSNG for both cases. In Case 3 *Scenario b*, variations in demand have minimal effect on LCOM and LCOSNG. As demand increases, the SNG share decreases from 38% (low demand) to 30% (high demand), with additional demand met through natural gas imports. Hence, in this scenario, higher demand primarily increases natural gas imports, while local SNG production remains nearly constant. In contrast, in Case 2, where all methane is produced locally, higher demand requires additional SNG production and thus more $H_2$ imports. Consequently, both LCOM and LCOSNG increase sharply as production scales with demand. This highlights that local SNG production is highly sensitive to demand fluctuations, whereas scenarios allowing natural gas imports are less affected.

### 3.5. Model validation

To verify that the model produces physically plausible outputs, an internal mass and energy balance closure at the Dietikon node (Case 1, current demand scenario) is performed using the underlying technology




(a)




(b)

**Fig. 12.** Impact of demand variation on the Levelized Cost of Methane (LCOM) (a) and Levelized Cost of SNG (LCOSNG) (b). Low/high demand is 30% below/above the reference demand.

parameters with the Sabatier stoichiometry and with published HHV-based conversion factors. Technology parameters used in the model are documented in the Supplementary Material and are consistent with published values.

At the Dietikon node, the capacities selected by the model reproduce the Sabatier stoichiometry and the Hydrogen/$CO_2$ mass balance, and captured $CO_2$ exactly matches the methanation demand. The local SOEC output does not cover the full hydrogen requirement, and the gap is closed by pipeline imports from the Horgen and Linth nodes. No $CO_2$ pipelines are deployed, consistent with the structural abundance of $CO_2$ captured locally at each WtE site. Detailed mass and energy balances for this node, together with the corresponding parameter checks, are reported in Supplementary Appendix D.

The methanation capacities selected by the model at the five WtE nodes (30–151 $MW_{CH_4}$ across scenarios, see Supplementary Appendix D) exceed the scale of any currently operating PtM plant. The largest operational plant in Switzerland is Limeco (~2 $MW_{el}$) and the largest in the world is Audi e-gas plant in Werlte, Germany (~6 $MW_{el}$). Since no PtM plant at the scale selected by the model is in operation, the model cannot be validated against a like-for-like installation; validation is instead established by (i) the stoichiometric closure and parameter consistency reported above and (ii) the cost comparison in Table 6 against published techno-economic assessments whose reference plant sizes are close to the range considered here. All reference studies, evaluate single-plant PtM configurations, whereas the present work considers a regional multi-node system with inter-site hydrogen transport and, in Case 2, large-scale seasonal LNG storage. To enable a like-for-like comparison, LCOSNG (cost of locally produced SNG only, excluding any NG imports) is reported here. For simplicity only Case 1 *future demand*, Case 2 and Case 3 *scenario b* are taken for comparison.

**Table 5**
Summary of sensitivity analyses: parameter, case tested, range, and LCOM response.

| Parameter | Case | Range tested | LCOM range (CHF/kWh) | Δ LCOM | Topology change |
|---|---|---|---|---|---|
| Grid electricity price | 1 | ±40% | 0.38 – 0.48 | −10%/ + 11%[a] | Fewer $H_2$ pipelines at high price |
| $CO_2$ pipeline CAPEX | 2 | −75% to ref | 0.16 – 0.17 | −1%/ + 1% | Yes (mixed topology at −40%/ − 50%) |
| $H_2$ import price | 2 | ±40% | 0.13 – 0.20 | −21%/ + 20% | Yes (mixed topology at −40%) |
| Methane demand | 2 | ±30% | 0.16 – 0.24 | −1%/ + 49% | No |
| Methane demand | 3b | ±30% | 0.15 | ±1% | No |

**Table 6**
Comparison of LCOSNG (locally produced SNG only) results with published PtM techno-economic assessments. The plant size is reported by location as a range. Values are reported in the currency used by each source.

| Study | Plant size [$MW_{SNG}$] | LCOSNG | Electricity | Notes |
|---|---|---|---|---|
| This work, Case 1 | 30–100 | 0.31–0.46 CHF/kWh | Swiss grid | 2050 demand |
| This work, Case 2 | 30–160 | 0.13–0.24 CHF/kWh | RE + $H_2$ imports | 2050 demand; 338 GWh seasonal LNG storage |
| This work, Case 3 | 30–100 | 0.11–0.15 CHF/kWh | RE + NG imports | 2050 demand; 39 GWh seasonal LNG storage |
| Böhm et al. (2020), PtG-PV | 50–100[a] | 0.08 EUR/kWh (2020); 0.04 EUR/kWh (2030)[b] | Dedicated PV | Single plant; ambitious CAPEX learning to 2050 |
| Brynolf et al. (2018), S4 | 50–200 | 0.16–0.60 EUR/kWh (2015); 0.12–0.28 EUR/kWh (2030) | Grid, 50 EUR/MWh | Single plant |
| Hannula (2015)[c] | 200 | 0.14 EUR/kWh | Grid, 50 EUR/MWh | Single plant; $CO_2$ from anaerobic digestion; future projection with 85% renewables. |
| Tremel et al. (2015)[c] | 28–32 | 0.170 EUR/kWh | 93 EUR/MWh | Single plant |

[a] Exception, values are in $MW_{el}$.
[b] Values correspond to PtG-PV configurations at 50 and 100 MW under learning-curve assumptions.
[c] Values extracted from the harmonized literature review of Brynolf et al. (2018), Tables 1 and 2.

The reported LCOSNG values span nearly an order of magnitude because the studies also differ in electricity supply and plant scale. Böhm et al. (2020) report the lowest values, coupling the plant directly to dedicated photovoltaic generation at 18–31 EUR/MWh and applying ambitious technological-learning reductions to CAPEX by 2030–2050. Brynolf et al. (2018), Hannula (2015) and Tremel et al. (2015) assume grid electricity at 50–130 EUR/MWh, yielding 120–600 $EUR/MWh_{SNG}$ (range across years and scales).

Case 1 (0.34–0.38 CHF/kWh) is at the upper end of this range because Swiss industrial grid electricity at 0.19 CHF/kWh dominates the operational expenditure: roughly four times the price assumed by Brynolf et al. and Hannula, and nearly an order of magnitude above the dedicated-PV cost used by Böhm et al. The ±40% electricity-price sensitivity (Section 3.4) keeps Case 1 LCOSNG within 0.30–0.43 CHF/kWh, still above the comparator range.

Case 2 (0.16 CHF/kWh) falls within the range reported by the size-scaled single-plant studies and is consistent with literature values for large-scale PtM plants supplied with lower-cost electricity. This figure depends on imported hydrogen at the IEA-projected price of 0.079 CHF/kWh (Table 1): the $H_2$ import-price sensitivity (±40%) shifts LCOSNG to 0.13–0.19 CHF/kWh, remaining inside the comparator range. Because 83% of the hydrogen feed is imported, the comparison is not strict, as in the reference studies all the hydrogen is produced on-site, but it remains informative on a per $/kWh_{SNG}$ basis.

The model therefore reproduces the expected sensitivity of LCOSNG to electricity price and plant scale across the covered by the published Techno-Economic Analysis.

## 4. Discussion

The results of the different cases are analyzed and compared in this section. Key findings are highlighted, and production costs are evaluated against current biogas market prices. According to Energie 360° (Energie 360 S.A., 2025), for 100% biogas the price is 0.229 CHF/kWh for households and 0.154 CHF/kWh for industries. In this study, a threshold of 0.200 CHF/kWh is considered as the maximum acceptable LCOM. The discussion is organized around resource availability, cost structure, sensitivity and emissions reduction, spatial system architecture, and finally limitations of the analysis.

### 4.1. Resource availability and seasonal effects

$CO_2$ availability is more than sufficient, consistent with findings from a national Swiss PtG study (Rüdisüli, 2025). Heat supply generally does not limit production, except during winter when heat availability is constrained due to district heating. SNG production primarily occurs during spring and summer, when renewable electricity generation is high and waste heat from WtE plants is available. Conversely, methane imports are concentrated in winter, when demand peaks for heating.

Renewable electricity availability is the main bottleneck for low-emissions $H_2$ production. In Case 2, only 17% of the $H_2$ demand in 2050 is produced locally, with the remainder imported. In Case 3, the maximum SNG share reaches 32% (*Scenario c*). Storage, particularly LNG storage, is essential to mitigate the variability of renewable electricity and demand fluctuations. For instance, in Case 2, large LNG storage capacities (approximately 340 GWh) reduce the LCOM to 0.16 CHF/kWh.

### 4.2. Cost structure and emissions reduction

Against the biogas benchmark of 0.20 CHF/kWh introduced at the beginning of Section 4, Case 2 (0.16 CHF/kWh) and Case 3 *Scenario b* (0.15 CHF/kWh) both fall below the threshold and are therefore cost-competitive with industrial biogas. These cases confirm that WtE-based PtM can become competitive with biogas when either low-emission hydrogen imports through the EHB are available or when a carbon tax adjustment is permitted, resulting in a combination of SNG production and natural gas imports.

Among all cases, OPEX is the largest cost component, mainly driven by electricity grid price, $CH_4$ and $H_2$ imports. In Case 1, relying solely on the electrical grid, both current and projected future demand scenarios yield LCOM values that are economically uncompetitive with biogas benchmark price. This is primarily due to high electricity costs. The assumed electricity cost of 0.19 CHF/kWh corresponds to the regulated C7 industrial tariff, which includes energy procurement, network usage, and regulatory surcharges. A ±40% variation around the C7 tariff shifts Case 1 LCOM by roughly the same proportion, confirming that electricity price is the dominant LCOM driver in the grid-only configuration. In practice, a PtG plant operator could procure electricity through alternative channels. On the Swiss wholesale market, average day-ahead prices were around 0.011–0.080 CHF/kWh in 2023 and 2024 (Bundesamt für Energie (BFE), 2024), to which network charges would be added. Alternatively, long-term power purchase agreements (PPAs) with renewable generators could provide price stability at intermediate levels. Furthermore, the flexibility of electrolyzers, which can modulate their load in response to price signals, would enable preferential operation during low-price periods, further reducing the effective electricity cost. The constant-tariff assumption is therefore considered conservative; time-of-use or PPA-based procurement strategies could reduce LCOM below the values reported here. Exploring such dynamic pricing strategies is identified as future work.

Regarding the $H_2$ import price, an equivalent ±40% variation around the assumed price shifts Case 2 LCOM from 0.13 to 0.19 CHF/kWh, and in the low-price case the optimum flips to a mixed configuration with 24% of hydrogen produced locally and $CO_2$ pipelines appearing in the network. Case 2 results are therefore dependent on EHB pricing assumptions rather than robust to them.

The assumed $CH_4$ import price is set deliberately above current spot prices to reflect a future carbon-adjusted scenario, and lower import prices would worsen Case 3 competitiveness.

Beyond cost, the cases differ in their emission reductions. These reductions are relative to a future demand baseline relying on 100% fossil natural gas, which results in 280 $ktCO_2$ annual emissions. In Case 1, 764 GWh/yr of SNG produced from waste-$CO_2$ displaces an equivalent volume of imported natural gas, avoiding approximately 174 $ktCO_2$/yr. Case 2 replaces the full methane demand with locally produced SNG. It uses only renewable energy, low-emission hydrogen and biogenic carbon, therefore it is considered to have no $CO_2$ emissions. Case 3 *scenario b* covers 314 GWh/yr of demand with SNG and the remainder through natural gas imports, its reduction reaches 72 $ktCO_2$/yr. In Case 2, where approximately 83% of hydrogen is imported, the realized reduction is therefore conditional on the EHB delivering certified low-carbon hydrogen. The reductions reported here should therefore be read as upper bounds, and a full life-cycle assessment of the regional system is identified as future work (Section 4.6).

### 4.3. Spatial architecture and infrastructure choices

Overall, the resulting system configurations exhibit a decentralized structure across all cases. In Case 1, PtG units are installed at every location. The electricity-price sensitivity (Section 3.4) does not distort the dispatch or deployment decisions of the optimizer: a ±40% variation leaves annual SNG production unchanged at 764 GWh/yr, with total system cost scaling more or less proportionally. This indicates that production in Case 1 is bound by physical constraints — waste-heat availability in winter and the installed technology capacities — rather than by the electricity tariff. In Case 2, PVs are installed in every location but electrolysis only happens at Hagenholz (having the largest PV area), the other locations import hydrogen from outside the system. In Case 3, where both NG imports and SNG production coexist, SNG is produced at some WtE plants, with higher production levels leading to the activation of additional sites and an expansion of the hydrogen pipeline network (scenario b vs scenario c). Even when a single location has sufficient resources, a spatially distributed production is favored over centralized configurations due to lower system costs. In addition, usually the models build several low-pressure $H_2$ pipelines as they are the cheapest and then add larger ones if needed (Case 1).

Carbon dioxide pipelines are not selected in any case. Relative to hydrogen, $CO_2$ transport is more expensive as it needs to be in supercritical conditions. The $CO_2$ pipeline cost sensitivity (Section 3.4) first shows that the model is cost insensitive. LCOM remains within ±1.2% compared to the base case. The topology choice is effectively interchangeable: the optimizer selects between near-equivalent configurations, with mixed-pipeline architectures emerging at intermediate reductions (40–60%) and the base topology returning at the strongest reduction (75%). This non-monotone response reflects the insensitivity of total system cost to $CO_2$ pipeline costs. Therefore, the reason why $CO_2$ pipelines are seldomly installed across the different cases is structural: across all cases, local $CO_2$ supply at each WtE node substantially exceeds the $CO_2$ that can be converted to SNG under the binding electricity, hydrogen, and waste-heat constraints. System-wide, only 36% of the available waste-$CO_2$ is methanated in Case 1 (current demand), 22% in Case 1 (future demand), and 34% in Case 2; the share is smaller still in Case 3, where natural gas imports partially displace SNG. Because every node operates with a local $CO_2$ surplus, there is no inter-site $CO_2$ imbalance for a pipeline to exploit, and the optimizer consistently installs a dedicated capture unit at each plant.

It should be noted that the operational coordination of such a distributed system — including scheduling, safety protocols, and contractual arrangements between plant operators — is beyond the scope of this techno-economic optimization and requires dedicated operational planning studies.

### 4.4. Cross-case viability comparison

Case 1 establishes the technical reference: SNG produced from waste-$CO_2$ using grid electricity for hydrogen, with no LNG storage or hydrogen imports. The resulting LCOM (0.34–0.42 CHF/kWh) lies well above the biogas threshold, so Case 1 is not cost-competitive at present Swiss grid prices. The remainder of this subsection compares Cases 2 and 3, which were designed to address this cost gap through different supply strategies.

Case 2 is formulated as a scenario exploring the cost implications of large-scale low-emissions hydrogen availability for regional SNG production. This scenario is motivated by two factors: first, the limited renewable electricity potential within the study region, which constrains local hydrogen production to approximately 17% of demand; and second, the strategic interest of EnergiNova AG in evaluating future supply configurations. The results show that, under these conditions, SNG can be produced at a competitive cost of approximately 0.16 CHF/kWh. The assumed hydrogen import relies on the planned European Hydrogen Backbone (EHB), a network of 53,000 km of hydrogen pipelines across 28 European countries envisioned by 2040, including a connection to Switzerland via Italy and Germany by 2030 (van Rossum et al., 2022). While the EHB initiative is supported by 33 European gas transmission system operators, the timeline and extent of its realization remain uncertain. Its realization depends on geopolitical stability, cross-border regulatory harmonization, and bilateral agreements, which constitute risks that are difficult to quantify in an optimization framework. The hydrogen price sensitivity analysis (Section 3.4) partially captures this risk, by changing the reference price given by the IEA of 0.079CHF/kWh in 2030 by ±40%, the LCOM ranges between 0.13–0.19CHF/kWh, still below the biogas price threshold. Should the backbone not materialize or deliver hydrogen at much higher cost, Case 3, which relies on local renewables and natural gas imports, represents the more conservative alternative.

This raises several strategic considerations for EnergiNova AG: whether to maintain methane delivery, fully transition to hydrogen distribution, build parallel hydrogen pipelines or blend $H_2$ and $CH_4$ in existing networks. It is worth noting that EnergiNova's current pipeline infrastructure is already $H_2$-compatible, implying that no major investments would be required for conversion. Moreover, hydrogen embrittlement risks are mitigated by the use of compatible pipeline materials, and the inter-site distances in the study area result in negligible pressure losses for the low-pressure pipelines considered (see Supplementary material, Appendix B). Safety regulations for hydrogen transport in Switzerland are governed by the Swiss Gas and Water

Industry Association (SVGW) (des Gas-und Wasserfaches , SVGW), under which the modeled configurations would operate.

Case 3 aligns more closely with the current Swiss energy situation, combining natural gas imports with local SNG production. EnergiNova AG must balance local production and imports to ensure a secure supply while optimizing cost and emissions, addressing the so-called *Energy Trilemma* — the simultaneous challenges of energy security, affordability, and sustainability. Moreover, current $CO_2$ taxes (120 CHF/tCO2) are too low for SNG production to be economically viable. At present rates, importing natural gas and paying the tax is cheaper than producing SNG from renewable sources. Higher future taxes on fossil fuels could incentivize PtM technologies.

Sensitivity analysis (Fig. 12) shows that Case 3 is more robust to demand variations than Case 2. In Case 2, 100% of methane is replaced by SNG, making LCOM highly sensitive to demand changes. In Case 3, increased demand primarily leads to higher natural gas imports, with little effect on local SNG production or LCOM.

### 4.5. Carbon capture and business models

In this study, the cost of $CO_2$ capture is included in the overall LCOM. In practice, waste incineration plants will need to install carbon capture units, potentially with financial support from the government (Maus et al., 2012). Captured $CO_2$ could be sold to EnergiNova AG, which would operate the PtG plant. Another option would be that the waste incineration plant operates the PtM plant itself and then sells the methane to EnergiNova AG. Alternative models include a third-party operator managing the PtG. Similarly, the electricity from hydropower plants for the hydrogen production is considered in this study as surplus and free, but future pricing or commercialization of $H_2$ could influence costs. These considerations highlight the need for further investigation of business models with all stakeholders.

### 4.6. Emissions scope

This study focuses on $CO_2$-equivalent emissions (Scope 2) as the primary environmental metric. A comprehensive assessment of non-$CO_2$ impacts, including acidification (NOx, SOx), eutrophication, and human toxicity, would require a full life cycle assessment, which is beyond the scope of this techno-economic analysis. Existing LCA studies of PtM systems (IEA Technology Collaboration Programme on Advanced Motor Fuels (AMF), 2024) indicate that the electricity source and the $CO_2$ source are the dominant drivers, suggesting that configurations using low-carbon electricity (Cases 2 and 3) would also perform favorably in these categories. A dedicated LCA of the regional system studied here is identified as future work. Moreover, a detailed power system analysis coupling electricity and gas networks is outside the scope of this study but represents a relevant direction for future work.

## 5. Conclusions

This study assessed the techno-economic performance of Waste-to-Energy-based Power-to-Methane systems for supplying regional gas networks using an hourly, multi-node optimization framework. The results show that synthetic natural gas production from waste incineration plants can contribute to reducing natural gas dependency and associated $CO_2$ emissions, but that deployment is primarily constrained by the availability of low-carbon electricity rather than by carbon dioxide or waste heat supply. While Waste-to-Energy plants provide stable and abundant $CO_2$ streams, renewable hydrogen production remains the main bottleneck across all scenarios.

The multi-node regional approach adopted in this study reveals system-level findings that cannot be obtained from plant-centric analyses: the cost-optimality of decentralized SNG production across multiple WtE sites, the co-location of $CO_2$ capture and methanation, the preference for low-pressure hydrogen pipelines over $CO_2$ transport infrastructure, and the critical role of seasonal LNG storage in reducing levelized costs. These interactions between sites, transport, and storage justify the additional modeling complexity relative to single-plant assessments.

Fully renewable configurations require either substantial hydrogen imports or additional renewable electricity capacity, while methane storage plays a key role in balancing seasonal mismatches between production and demand. Systems combining renewable electricity, low-emissions hydrogen imports, and LNG storage achieve the lowest LCOM (Case 2, 0.13–0.20 CHF/kWh under projected 2050 demand), in line with current biogas prices. Although natural gas imports remain cost-effective under current conditions, higher $CO_2$ pricing would significantly improve the competitiveness of locally produced SNG.

Overall, the findings highlight that the viability of Waste-to-Energy-based Power-to-Methane plants depends on access to low-carbon electricity, adequate storage integration, and policy signals such as carbon pricing. These insights support strategic planning to enhance regional energy sufficiency and to defossilize regional gas networks.

## CRediT authorship contribution statement

**Sinda M'Saada:** Writing – original draft, Visualization, Validation, Methodology, Investigation, Conceptualization. **Zoe Stadler:** Writing – review & editing, Supervision, Project administration.

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## Declaration of generative AI and AI-assisted technologies in the manuscript preparation process

During the preparation of this work the authors used Claude AI in order to rewrite some sections of the manuscript. After using this tool/service, the authors reviewed and edited the content as needed and takes full responsibility for the content of the published article.

## Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Sinda M'Saada, Zoe Stadler reports financial support was provided by Innosuisse Swiss Innovation Agency. Sinda M'Saada, Zoe Stadler reports financial support was provided by EnergiNova AG. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.egyr.2026.109532.

## Data availability

The original contributions presented in the study are included in the article and the Supplementary Material, further inquiries can be directed to the corresponding author.

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