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SWEET P+D project H2-districts

Spitzenlastversorgung von Quartierenergiesystemen mit Hilfe von stationären Wasserstoff-Brennstoffzellen

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Summary

The H2-districts project investigates how stationary hydrogen-fuel-cells (FCs) can be integrated into district energy systems to provide peak-shaving, grid-support and thermal services while reducing CO_2 emissions. The project is motivated by the growing mismatch between rising winter electricity demand—driven by heat-pump uptake and electric-vehicle charging—and limited local generation in winter, which creates high-cost peak loads and stresses distribution grids. By coupling a 60 kW_{el} PEMFC (the "kvyreen" prototype) with a medium-temperature district-heating network at Empa's NEST+move demonstrator, the consortium explores the technical feasibility, control strategies and economic viability of using hydrogen-powered combined-heat-and-power (CHP) units as flexible assets.

The approach combines a field-tested pilot, detailed data acquisition, and model-based optimization. A model-predictive controller (MPC) receives short-term load forecasts (generated with XGBoost) and cost signals (electricity tariffs, peak-power fees, hydrogen price) and determines optimal set-points for the FC, heat pump and thermal storage. Experiments over a two-month period (Feb–Apr 2025) quantify system efficiencies, ramp-rates and the impact of auxiliary loads, while a mixed-integer linear programming (MILP) design tool evaluates techno-economic performance across a range of demand profiles, climate scenarios and ageing assumptions. Sensitivity analyses (via Morris' method) identify peak-power fees, FC capital cost and lifetime as the dominant drivers of optimal sizing.

Key results show that the FC can track power set-points under three minutes, achieving system electrical efficiencies of 40-48% and thermal efficiencies of 30-50% depending on load. In the local case study (NEST building) peak-shaving yields modest cost reductions (~3%) because of a flat load profile, whereas extending the control to the wider Empa campus (global case) improves total operational costs by over 10% thanks to larger winter peaks. Techno-economic analysis reveals that second-life FCs become competitive only when peak-power fees exceed ~18 CHF/kW and demand scales above ~500MWh eq/year; under these conditions, they can defer grid-reinforcement investments (≈1.4kCHF per 22kW peak reduction) and lower annual operating costs by ~1.5%.The use of ageing models from the literature indicates that degradation is primarily affected by high-power operation. When ageing effects are considered in design optimization cases where FC operates as a base load unit, the optimal FC size is reduced by up to 28% for long-term planning horizons, while CHP operation slightly offsets efficiency losses.

H2-district concludes that hydrogen-fuel-cell units are technically viable for district-scale peak-shaving if operated correctly, especially in sectors with strong seasonal demand (e.g., schools, restaurants) and where air-source heat pumps dominate. Economic benefits hinge on future electricity tariff structures, peak-power fees and CO_2 pricing, as well as on the availability of affordable second-life FCs. Future work should refine long-term degradation models, expand forecasting horizons, and explore revenue streams from ancillary grid services to enhance the business case for widespread deployment.

Zusammenfassung

Das H2-districts Projekt untersucht, wie stationäre Wasserstoff-Brennstoffzellen (FC) in Quartiersenergiesysteme integriert werden können, um Lastspitzen zu glätten, das Stromnetz zu unterstützen und gleichzeitig thermische Leistungen zu erbringen sowie CO_2-Emissionen zu reduzieren. Das Vorhaben motiviert aus steigender Winterstromnachfrage – bedingt durch die Verbreitung von Wärmepumpen und das Laden von Elektrofahrzeugen – und begrenzter dezentraler Erzeugung, wodurch teure Lastspitzen entstehen, und das Verteilungsnetz belastet wird. Durch die Kopplung einer 60 kW_{el} Brennstoffzelle (Prototyp „kvyreen“) mit dem elektrischen- und wärmenetz am NEST+move-Demonstrator der Empa wird die technische Machbarkeit, geeignete Betriebsstrategien und die ökonomische Tragfähigkeit von wasserstoffbetriebenen Kraft-Wärme-Kopplungsanlagen als flexible Ressourcen geprüft.

Der Ansatz kombiniert einen im Feld getesteten Piloten, detaillierte Datenerfassung und modellbasierte Optimierung. Ein modellprädiktiver Regler (MPC) erhält Lastprognosen (mittels XGBoost) sowie Kostensignale (Stromtarife, Spitzenlastgebühren, Wasserstoffpreis) und bestimmt optimale Sollwerte für die Brennstoffzelle, die Wärmepumpe und den thermischen Speicher. Experimente über einen Zeitraum von zwei Monaten (Februar-April 2025) quantifizieren Systemwirkungsgrade und Ansprechzeiten. Sensitivitätsanalysen (mittels Morris-Methode) zeigen, dass Spitzenlastgebühren, Kapitalkosten der FC und deren Lebensdauer die entscheidenden Treiber für die optimale Dimensionierung sind.

Die wichtigsten Ergebnisse zeigen, dass die FC unter drei Minuten den Leistungs-sollwert verfolgt und dabei System-elektrische Wirkungsgrade von 40-48% sowie thermische Wirkungsgrade von 30-50% je nach Last erreicht. Im lokalen Anwendungsfall (NEST-Gebäude) führt das Lastspitzen-Shaving zu Kosteneinsparungen von etwa 3%, da das verhältnismässig kleine Lastspitzen verursacht; erst die Ausweitung des Betriebs auf das gesamte Empa-Campus-Gebiet (globaler Fall) verbessert die Gesamtkosten um mehr als 10%, da dort grössere Winterlastspitzen auftreten. Die technoökonomische Analyse zeigt, dass Second-Life-FCs erst ab Spitzenlastgebühren von rund 18 CHF/kW und einem Jahresäquivalenzbedarf von über 500 MWh wirtschaftlich werden; unter diesen Bedingungen können sie Investitionen in die Netzverstärkung (≈ 1,4kCHF pro 22 kW Spitzenreduktion) verzögern und die jährlichen Betriebskosten um etwa 1,5% senken. Die Verwendung von Alterungsmodellen aus der Literatur zeigt, dass die Degradation in erster Linie durch den Betrieb mit hoher Leistung beeinflusst wird. Wenn Alterungseffekte bei der Designoptimierung berücksichtigt werden, bei der die Brennstoffzelle als Grundlastanlage betrieben wird, reduziert sich die optimale Brennstoffzellengröße für langfristige Planungshorizonte um bis zu 28 %, während der KWK-Betrieb Effizienzverluste leicht ausgleicht.

Die Projektresultate zeigen, dass Wasserstoff-Brennstoffzellen technisch geeignet sind, um in Quartieren Lastspitzen zu glätten, insbesondere in Sektoren mit stark saisonaler Nachfrage (z. B. Schulen, Restaurants) und dort, wo Luft-Wärmepumpen dominieren. Der wirtschaftliche Nutzen hängt von zukünftigen Stromtarifen, Spitzenlastgebühren und CO_2-Preisen sowie von der Verfügbarkeit kostengünstiger Second-Life-FCs ab. Weiterführende Arbeiten sollten Langzeit-Degradationsmodelle verfeinern, Prognosehorizonte erweitern und zusätzliche Erlösquellen aus Netzdienstleistungen prüfen, um das Geschäftsmodell für eine breitere Einführung zu stärken.

Résumé

Le projet H2-districts étudie comment les piles à combustible à hydrogène stationnaires (FC) peuvent être intégrées aux systèmes d'énergie de quartier afin de fournir du pic-shaving, un soutien au réseau et des services thermiques tout en réduisant les émissions de CO_2. Le projet est motivé par le déséquilibre croissant entre la hausse de la demande d'électricité en hiver – due à l'adoption des pompes à chaleur et à la recharge des véhicules électriques – et la production locale limitée pendant la saison froide, ce qui crée des charges de pointe coûteuses et met sous tension les réseaux de distribution. En couplant une pile à combustible PEMFC de 60 kWel (le prototype « kvyreen ») à un réseau de chauffage urbain à température moyenne sur le démonstrateur NEST+move d'Empa, le consortium explore la faisabilité technique, les stratégies de contrôle et la viabilité économique de l'utilisation d'unités combinées chaleur-électricité (CHP) alimentées à l'hydrogène comme actifs flexibles.

L'approche combine un pilote testé sur le terrain, une acquisition de données détaillée et une optimisation basée sur des modèles. Un contrôleur prédictif (MPC) reçoit des prévisions de charge à court terme (générées avec XGBoost) ainsi que des signaux de coût (tarifs électriques, frais de puissance de pointe, prix de l'hydrogène) et détermine les points de consigne optimaux pour la FC, la pompe à chaleur et le stockage thermique. Des expériences menées sur deux mois (février-avril 2025) quantifient les rendements du système, les taux de montée en puissance et l'impact des charges auxiliaires, tandis qu'un outil de conception basé sur la programmation linéaire en nombres entiers mixtes (MILP) évalue la performance techno-économique selon différents profils de demande, scénarios climatiques et hypothèses de vieillissement. Des analyses de sensibilité (méthode de Morris) identifient les frais de puissance de pointe, le coût d'investissement de la FC et sa durée de vie comme principaux facteurs déterminants de la taille optimale.

Les résultats clés montrent que la FC peut suivre les consignes de puissance en moins de trois minutes, atteignant des rendements électriques de 40-48 % et des rendements thermiques de 30-50 % selon la charge. Dans l'étude de cas locale (bâtiment NEST), le pic-shaving entraîne une réduction modeste des coûts (~3 %) en raison d'un profil de charge plat, alors que l'extension du contrôle à l'ensemble du campus Empa (cas global) améliore les coûts opérationnels totaux de plus de 10 % grâce à des pointes hivernales plus importantes. L'analyse techno-économique révèle que les FC de seconde vie ne deviennent compétitives que lorsque les frais de puissance de pointe dépassent ~18 CHF/kW et que la demande dépasse ~500 MWh eq/an ; dans ces conditions, elles permettent de différer les investissements de renforcement du réseau (≈1,4 kCHF par réduction de pointe de 22 kW) et de réduire les coûts d'exploitation annuels d'environ 1,5 %. L'utilisation de modèles de vieillissement tirés de la littérature indique que la dégradation est principalement affectée par un fonctionnement à haute puissance. Lorsque les effets du vieillissement sont pris en compte dans les cas d'optimisation de la conception où la pile à combustible fonctionne comme une unité de charge de base, la taille optimale de la pile à combustible est réduite jusqu'à 28 % pour les horizons de planification à long terme, tandis que le fonctionnement en cogénération compense légèrement les pertes d'efficacité.

H2-district conclut que les unités à pile à combustible hydrogène sont techniquement viables pour le pic-shaving à l'échelle d'un quartier si elles sont correctement exploitées, notamment dans les secteurs présentant une forte demande saisonnière (écoles, restaurants) et où les pompes à chaleur aérothermiques dominent. Les bénéfices économiques dépendent des futures structures tarifaires de l'électricité, des frais de puissance de pointe et de la tarification du CO_2, ainsi que de la disponibilité de FC de seconde vie abordables. Les travaux futurs devraient affiner les modèles de dégradation à long terme, élargir les horizons de prévision et explorer les sources de revenus provenant des services auxiliaires du réseau afin d'améliorer le cas d'affaires pour un déploiement généralisé.

Main findings («Take-Home Messages»)

- The hydrogen fuel cell CHP prototype can deliver rapid (≤ 3min) power ramps and achieve system electrical efficiencies of 40-48% and thermal efficiencies of 30-50%, proving its technical suitability for district scale peak shaving.
- When coordinated with model predictive control across the pilot case, the fuel cell operation reduces total operational costs by more than 10% and cuts peak import power by ~10kW, demonstrating tangible grid reinforcement savings that align with Switzerland's goal of deferring costly network upgrades.
- Economic viability hinges on high peak power fees (≥18CHF/kW) and sufficient seasonal demand; under these conditions, second life fuel cells become cost effective, delivering up to 1.5% annual operating cost reductions and supporting the Swiss energy strategy of increasing renewable integration while limiting CO_2 intensive peak generation.
- Incorporating ageing aware optimization shows that accounting for fuel cell degradation can shrink optimal sizing by up to 28% for long term planning, ensuring realistic investment assessments and reinforcing the policy emphasis on durable, low carbon flexibility assets in future Swiss energy systems.

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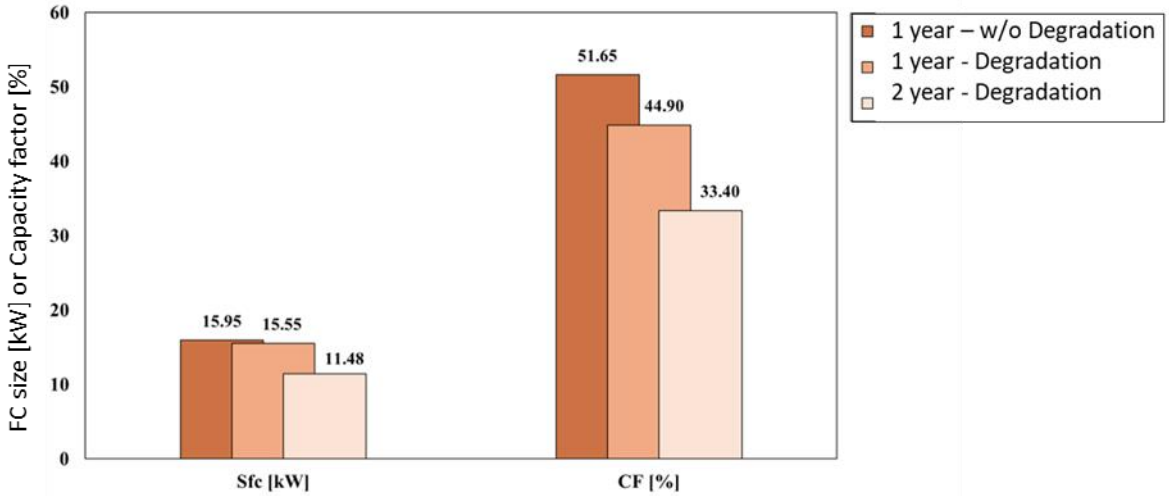

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List of abbreviations

ASHP	Air-sourced heat pump
BES	Battery energy storage
BoL	Beginning of life
CF	Capacity Factor
CHP	Combined heat and power
COP	Coefficient of Performance
DHN	District Heating Network
DSO	Distribution Grid Operator
e-HRS	Electric Hydrogen Refueling Station
FC	Fuel cell
FLFC	First-life fuel cell
GSHP	Ground-source heat pump
H_2	Hydrogen
HP	Heat pump
HT	High-temperature
LHV	Lower heating value
MFH	Multi-Family House
MILP	Mixed Integer Linear Programming
MPC	Model Predictive Control
MS	Milestone
MT	Medium-Temperature
P&ID	Piping and Instrumentation Diagram
PV	Photovoltaics
RES	Renewable energy sources
SFH	Single-family house
SFOE	Swiss Federal Office Of energy
SOC	State of charge
SLFC	Second-life fuel cell
VSE	Verband Schweizerischer Elektrizitätsunternehmen (Association of Swiss DSOs)
TAC	Total annualized cost
TES	Thermal energy storage
WHR	Waste heat recovery
WP	Work package
ZEV	Zusammenschluss zum Eigenverbrauch (prosumer communities)
ZH	Zurich

1 Introduction

1.1 Context and motivation

The trend towards electricity as the main energy carrier, as well as the use of additional decentralized loads and productions, increases the utilization of the distribution grid significantly. The electrification of building heating and mobility, in particular, are driving energy consumption strongly, with the coverage of this demand currently still largely based on fossil fuels. During winter, there is typically a higher energy demand compared to summer. In contrast, summer experiences an increased share of renewables in the grid, combined with relatively lower local consumption. To address this discrepancy, various concepts have been developed to store the "excess electricity" generated in summer for later use during winter. Several of these storage concepts employ hydrogen (H_2) as an energy carrier, leveraging its capabilities for efficient and effective energy storage, as indicated in the VSE study "Energy Future 2050" [1]. Out of the SFOE SWEET PATHFNDR consortia, technology models and simulation environments are available for district energy system setups, including hydrogen.

The aim of this project is to explore the potential of utilizing hydrogen-powered fuel cells (FCs) as combined heat and power systems (CHPs) within district energy systems. By implementing this solution, several benefits can be achieved, including reduced grid loads during the crucial winter months and enhanced security of supply generally. Ultimately, this integration of fuel cells contributes to a more flexible and resilient energy system, which poses a counter trend, i.e. not adding additional electrical loads for heating, but co-generating heat and electricity in crucial winter periods, where renewable supply of electricity tends to be low. In addition, by using renewable hydrogen which leads to reducing the import of electricity with high carbon footprint, the overall CO_2-Emissions can be reduced. Continuing available works from SFOE SWEET PATHFNDR, the H2-districts project deepens the understanding of systemic interactions on the demand side when hydrogen technologies are introduced. Learnings were fed back to PATHFNDR in order to inform larger scale studies conducted in that project.

The foreseeable widespread use of heat pumps, especially air-sourced heat pumps, will cause an increased power demand and heavy grid load in the future. This increased load is emphasized when outside temperatures are low in winter. This problem is well described in [3]. The relevant key points of this study, developed by DSO's, are listed here:

- On average, the measured peak power of heat pumps is approx. 60% higher than the declared peak power. The reason for this is, that the declared peak power in the installation permission is often derived from the nominal power, which represents a mean operation point and is not the worst case at the lowest outside temperature.
- In operation, heat pump power peaks coinciding strongly with other grid load peaks in winter.
- Power control by electricity suppliers only allows for short-term relief, longer control actions lead to rebound effects.
- The first real grid overloads caused by heat pumps in certain areas are expected in the 2030s during cold winters.

Furthermore, relating impacts for the Swiss energy system 2050:

- Heat pumps could cover 80% of heating demand (Switzerland 2050)).
- Additional grid load: 5-7 GW during cold periods, corresponding to approximately 60% of today's maximum grid load.
- Regional differences depend on outside temperature and grid structure.

In addition to the higher grid load caused by heat pumps, also the additional power and energy for charging battery-electric vehicles in buildings and districts will significantly contribute to grid load. The application of fuel cells for this kind of application, are not considered a competitor to heat pumps in the project consortia but are necessary to support the ramp-up of heat pumps and e-mobility as well as to implement the goals of the 2050 Climate Strategy.

It should also be noted that in winter, due to electricity imports or, in the future, the operation of fossil-fueled peak-load power plants, the specific carbon footprint from imported electricity is typically 3-4 times higher than in summer. Whenever buildings require large amounts of electricity (e.g., for heating and EV charging) at times with high carbon footprint of grid electricity, buildings contribute to high CO_2 emissions.

Hydrogen-sourced fuel cells have gained momentum in recent years, supported by numerous research and demonstration [4] and an increasing number of commercial products. At scales relevant to this project (below 100 kW), polymer electrolyte membrane fuel cells (PEMFCs) are commercially available from companies such as. Typical electrical efficiencies range between 40–55%, while total (electrical + thermal) efficiencies up to 90% depending on operating conditions. Reported unit costs vary between CHF 2000–6000 per kWel for small systems. Such relatively high investment costs often limit the cost-effectiveness of PEMFCs. for small systems. Such relatively high investment costs often limit the cost-effectiveness of PEMFCs.

To reduce costs and promote circular economy principles, second-life fuel cell stacks from mobility applications represent a promising option for stationary CHP. End-of-life in vehicle use typically occurs earlier than in stationary operation, and system sizes match well with small-district energy systems. The lifetime of first-life PEMFCs for stationary applications typically ranges between 40'000 and 60'000 hours, corresponding to approximately 7.5–10 years of operation for base-load use (e.g., 5'000 hours/year), as reported in Table 1. Increasing system lifetime has a positive impact on overall cost-effectiveness. Current research focuses on improving material durability and system integration to extend operating life. In parallel, identifying application contexts where a limited number of operating hours can still yield profitable operation is also considered a viable strategy to enhance the economic viability of PEMFCs.

Table 1 Overview of key techno-economic assumptions from literature and technology databases for small-scale PEMFC used as combined heat and power units.
(*) When lifetime is reported in years, PEMFC operation as a base-load unit is assumed (≈5000 hours/year).
(**) Fixed installation costs, such as engineering and piping, are not included in this parameter.

Reference	*Lifetime (*) [years or hours]*	*Capex per installed capacity (**) [CHF/kW]*	*Electrical Efficiency [-]*	*Thermal Efficiency [-]*
CROSSDat – SWEET-CROSS	7.5 years	2'975	0.575	-
ehubX internal database	7.5 years	3'294	47.5	42.5
https://www.sciencedirect.com/science/article/pii/S1876610219308483	60'000 hours	1'975	-	-
https://www.sciencedirect.com/science/article/pii/S0196890423007549#t0060	-	2'583	0.41	0.34
https://sweet-cross.ch/data/technology-assumptions-models/2023-02-28/	-	6'300	-	-
https://www.research-collection.ethz.ch/handle/20.500.11850/403923	10 years	-	0.55	0.3

The application and the long-term economic profitability of such a system will heavily depend on future CO_2 taxation, electricity tariffs, grid load fees, and cost savings resulting from avoiding grid expansion. Furthermore, it is conceivable that income from grid services will also make a significant contribution to the profitability of such systems.

1.2 Project objectives

This project investigates the use of hydrogen fuel cells integrated into neighborhood energy systems to provide operational flexibility. If operated with sustainably produced hydrogen, they can provide decentralized, renewable, electrical, and thermal energy. In this project, a pilot plant is installed in NEST+move at Empa to experimentally investigate the use of hydrogen fuel cells for electrical grid-support as well as for thermal boosting of the heating system, while minimizing CO_2-Emissions. Specifically, the kvyreen prototype of the SFOE project "e-HRS" was adapted and operated as an integrated pilot plant. Grid-relieving operating strategies were developed and validated on the plant. Furthermore, the extent to which heat pumps and thermal and electrical storage technologies can be used in combination with the pilot plant for grid-supportive purposes was investigated. In detail, it will be investigated to what extent the specific disadvantages of air-sourced heat pumps could be compensated for by operating them in combination with a fuel cell system. Attention will also be paid to the behavior of the fuel cell system over its lifetime.

The following questions (Q1, Q2 and Q3) were to be answered:

Q1: How and to what extent can the flexibility provided by hydrogen fuel cells in district energy systems be maximized and how much grid reinforcement cost can be deferred or saved?

> The focus will be on defining various control strategies that consider both thermal demand and storage capacities, as well as power-controlled solutions for grid relief and/or local demand coverage. By optimizing the operation of the system for these use cases jointly, cost efficiency and increased flexibility will be achieved, thus enabling effective management of energy resources.

Q2: What district settings are most suited for such systems?

> As classical gas fired combustion CHPs, the proposed hydrogen fuel cell systems can provide power and heat simultaneously, serve as heating system in cases where heat pumps are not allowed, quotas already have been met, or be a component in a ZEV energy hub.

Q3: How does aging affect the fuel cell performance and lifetime during stationary applications?

> This effect over the years may have an impact on the fuel cells' capabilities to provide services on the electricity side. To better understand the added value of such systems, this question will be investigated, and findings include in the resulting models, recommendations and guidelines.

2 Approach, method, results and discussion

2.1 Pilot system

First, a building permit had to be granted by the City of Dübendorf. Compiling the necessary documentation commenced with the project kick-off on 01. October 2023. The foreseen pilot installation was novel for the public entity; acquiring the building permit took several iterations with representatives of different offices, with each subsequent request for documentation dedicated to a different office. After having finally received the construction approval (dt. 'Baufreigabe') on 18. June 2024, construction works started the following day.

The kvyreen system was installed in NEST+move and integrated in terms of electrical, thermal, and data connections. The kyvreen system is located next to the move demonstrator in the Empa campus, Dübendorf, as shown in Figure 1. Detailed P&IDs were developed for both electrical and thermal integration, as depicted in Figure 2 and Figure 3. The kyvreen system has a nominal power output at the beginning of life of 60kW$_{el}$ (at the module level), which is expected to reduce to 52kW at the end of life. The system can be modulated, with a minimum power output set at 10kW$_{el}$. The hydrogen is supplied from a gas-bundle located next to the kvyreen system, with a supply pressure between 10 and 15bar and a nominal mass flow rate of 3.6kg/h. Regarding the cooling of the system, the adopted heat transfer fluid is Water/Glycol 50%, and the nominal thermal power matches the electrical one (60kW$_{th}$). The recovered heat is transferred into the medium-temperature district heating network of the Empa campus, which operates in the range from 28 to 38°C.

(a) (b) (c)

Figure 1 (a) Final location selected for the kvyreen system next to the move demonstrator; (b) fuel cell system; (c) auxiliaries and heat exchanger.

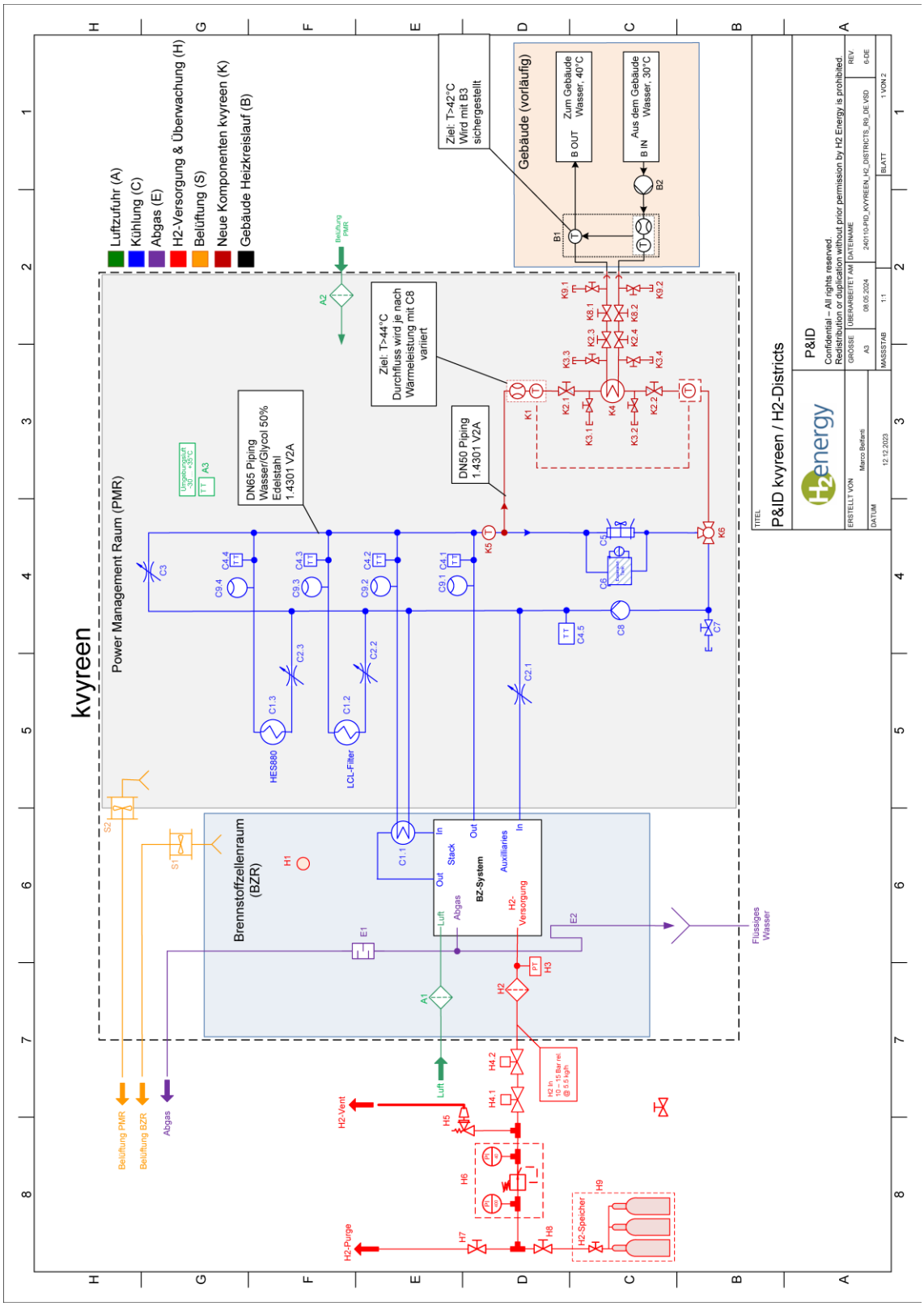


Figure 2 P&ID for the thermal integration of the kvyreen system into NEST+move.

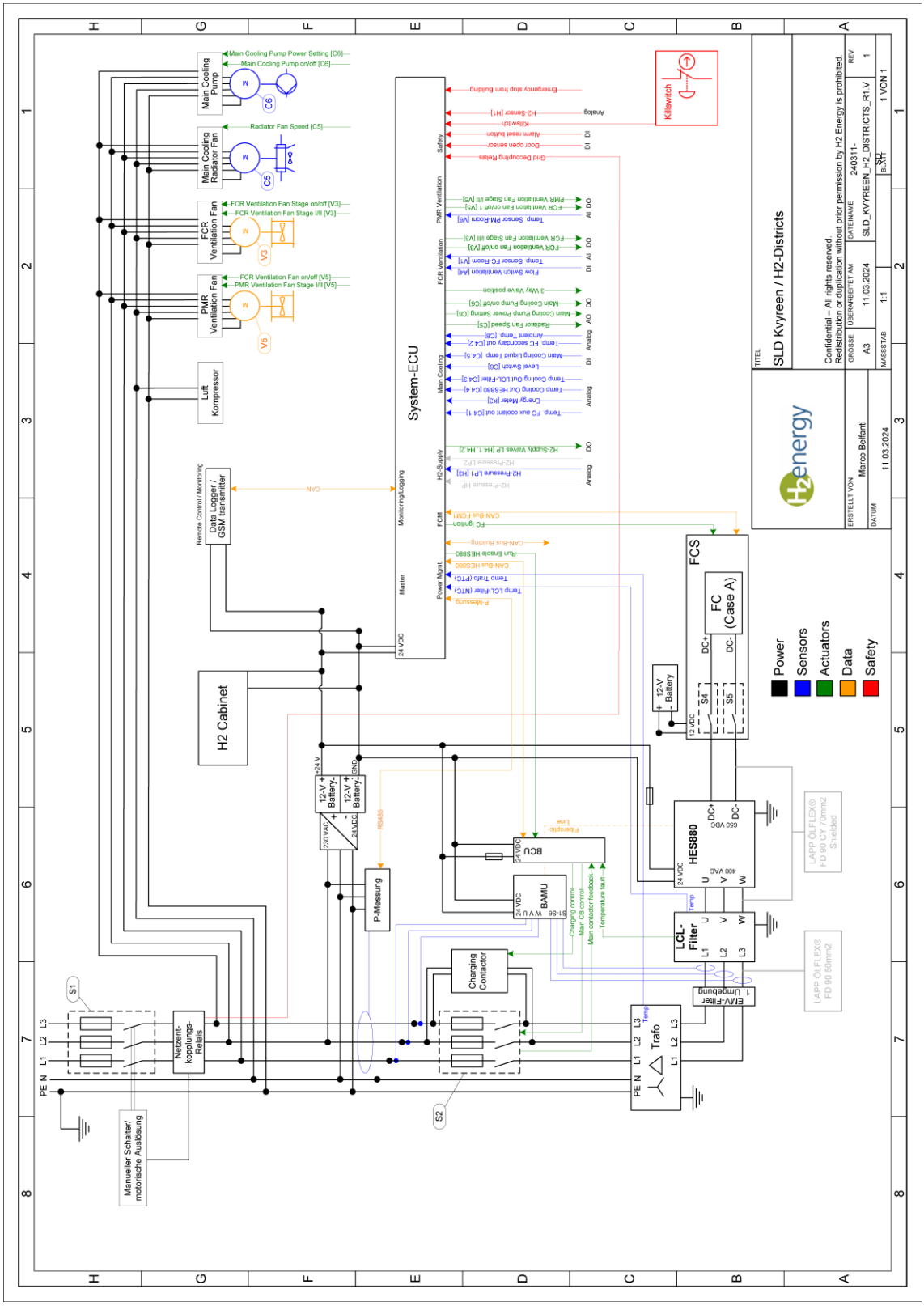


Figure 3 P&ID for the electrical integration of the kvyreen system into NEST+move.

2.2 Analysis of collected data

Experimental data were generated according to the MPC strategy detailed in Section and were systematically analyzed for the time frame from 27. February to the 8. April 2025. In this period, around 120kg of H_2 were consumed (≈11 bundles), for ≈138 hours of operation, of which only 3 hours at the stack nominal load of 60kW$_{el}$ and ≈117 hours at power below 20kW$_{el}$. The energy production in the analyzed time period was calculated as 1.76MWh$_{el}$ and 1.54MWh$_{th}$. The data was collected with 1-minute resolution.

An operational snapshot for several hours of operation from the Empa's Grafana dashboard is depicted in Figure 4. Here, it is possible to observe the good tracking capability of the kvyreen system for the electrical power compared to the setpoint. The thermal power behavior was difficult to predict, as it largely depends on the thermal inertia of the heat transfer system and the history of the system. The time required to achieve the desired temperature (40°C) for the water returning to the building heating distribution system is affected by the initial temperature. If the system is not operated for a relatively long period of time, the pipes and water temperature drop, leading to a longer heating-up period to achieve the desired temperature. In the instance of the NEST pilot, an idle time of 2 hours could lead to a water temperature below 30°C, with consequent response time of 10-15 minutes. The prototype system's low insulation and thermal inertia lead to ineffective heat recovery when trying to couple electrical peak shaving services (a few hours per month) to heat provision. Nevertheless, it must be noted that the kvyreen system was not insulated properly. Initially, the system was indeed designed to dissipate heat, as it was not conceived for heat recovery but rather heat dissipation. In a dedicated kvyreen for building applications, all pipes and hoses will be properly insulated, and thermal inertia of the whole system will be significantly reduced.

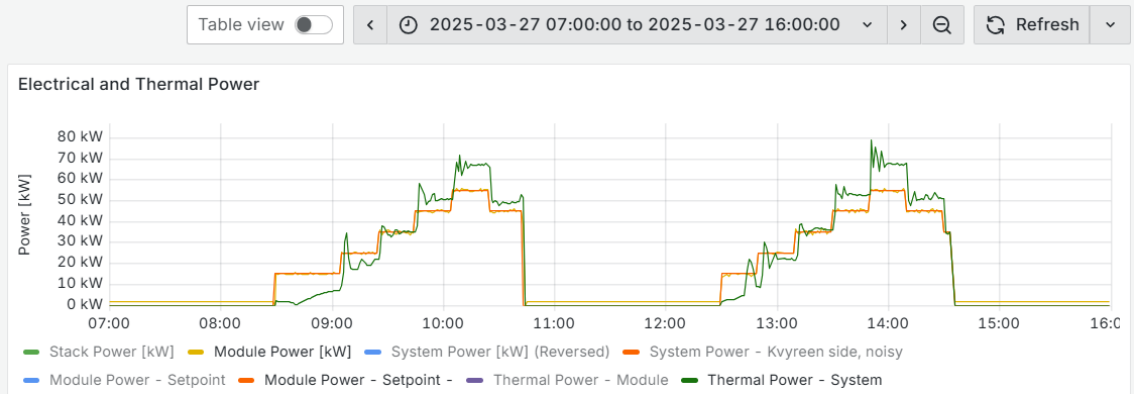


Figure 4 Example of measured data from a few hours of operation from Empa's Grafana's dashboard. The figure depicts the setpoint for the module power (orange) and the module power (yellow). Good tracking capability can be observed. Further, the figure depicts the thermal power provided from kvyreen, in green.

The system presented fast response capabilities; it was able to switch on and ramp up its power from 0 to 60kW in 2 to 3 minutes (a finer quantification was not possible due to the measurement resolution of 1 minute) and from 60 to 0kW in 1 to 2 minutes. Ramping up from 0 to min load (10kW) was possible in less than 1 minute.

The electrical efficiency, defined as the ratio between the produced electrical power and the consumed hydrogen (LHV-based), is depicted in Figure 5 (a) and (b), respectively for the stack and the system boundaries. The stack boundary considers the electricity produced at the stack level, obtained by the multiplication of the voltage and current readings. The system boundary considers the power readings at the interface between the kvyreen system and the NEST+move. In other words, the system boundary considers the electricity produced by the stack minus the electricity consumed by the auxiliary components of the kvyreen system (i.e., ventilation fans, cooling radiant fan, cooling pump, control system,

inverter, H_2 cabinet, and stack-level sensors, etc. as depicted in Figure 3). As can be observed in Figure 4, the auxiliary components largely affect efficiency and modify its profile. Concerning system efficiency, Figure 5(b), this ranges between 40 and 48%, thus lower than the efficiency assumed before installation.

As the stack efficiency decreases linearly with the workload and the auxiliary components have better performance at higher loads, the maximum efficiency (48%) is reached at fuel cell workload of 0.57 (34.2kW). Minimum efficiency is instead achieved at full load. For example, at 55kW_{el} stack power, auxiliary power is around 13kW_{el}. The thermal system efficiency, Figure 5(c), increases with workload. It ranges from 30 to 50%, with maximum efficiency at full load. Compared to the electrical efficiency calculation, a higher variance is observed as both hot and cold start-ups were considered.

Also, with respect to overall efficiency it has to be taken into consideration, that the layout of kvyreen prototype was not specifically designed for building applications and that a dedicated, updated version of kvyreen design would have significantly better overall efficiency. Efficiency is defined as the ratio between the electricity produced divided by the H2 mass flow rate multiplied by the LHV. The fuel cell workload is defined as the electricity produced at the stack level divided by its nominal power of 60kW.

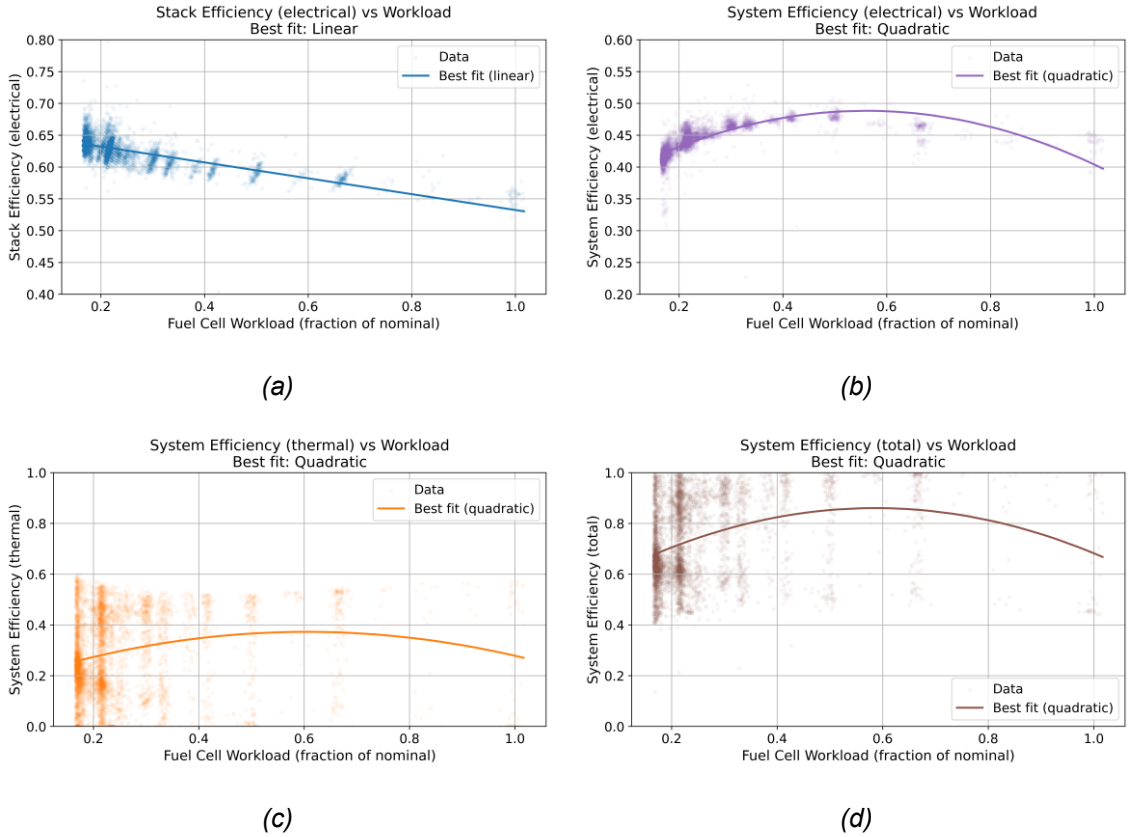


Figure 5 Efficiency curves for the kvyreen system: (a) electrical stack efficiency and (b) electrical system efficiency (including auxiliaries of the kvyreen system), (c) thermal system efficiency and (d) total system efficiency.

Table 1 Polynomial fits for the most important efficiency curves.
The symbol *y* represents the efficiency curve, and *x* represents the fuel cell workload (output module electrical power over nominal power). The dataset analyzed consisted of the data collected over 2 months of operation with minimal filtering (elimination of outliers for efficiency values below 0 and above 100%). The R^2 value for the system thermal efficiency is low, as both cold and hot startups were considered in the analyzed dataset.

Curve	Adopted fit	Equation	R^2
Stack electrical efficiency	Linear	$y = -0.1157x + 0.6545$	0.60
System electrical efficiency	Quadratic	$y = -0.3824x^2 + 0.4344x + 0.3606$	0.58
System thermal efficiency	Quadratic	$y = -0.3981x^2 + 0.7297x + 0.1851$	0.10
System total efficiency	Quadratic	$y = -1.0399x^2 + 1.2194x + 0.5028$	0.10

2.3 Development and test of grid-supporting operating strategies

The objective of this work package was to develop and validate a control strategy for minimizing operational costs, including peak power costs, through coordinated operation of the energy systems in the NEST building in Dübendorf, together with the newly installed fuel cell. Grid-supportive operation is defined here as optimizing operations while explicitly considering peak power costs, thereby performing peak shaving alongside other demand management measures.

Two case studies with different objectives are evaluated:

1. **Local - Case Study:** Optimize NEST operations to minimize operational costs and support the NEST grid connection by shaving peak loads.
2. **Global - Case Study:** Optimize NEST operations to minimize operational costs and support both the NEST and Empa-Campus grid connection points.

The electrical load in the Empa-Campus is uncontrollable. It does not represent the entire campus, as data was only available for a subset of selected buildings on the campus.

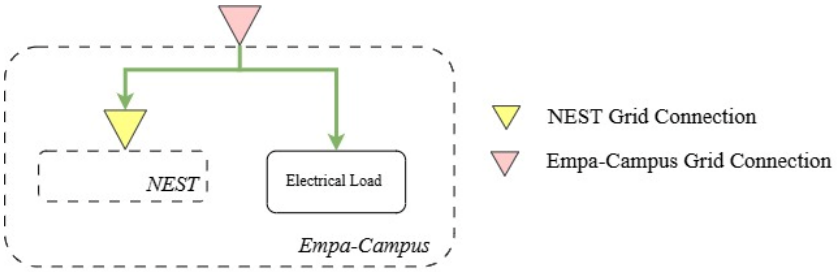


Figure 6 Case study system boundaries with grid connection points.

Figure 7 shows both physical and controller related components of NEST, and the way they interact. The local grid connection point highlighted in yellow is shown in both Figure 6 and Figure 7.

Physical layer, NEST comprises of multiple energy technologies: a 24kW$_{el}$ heat pump (minimum electric power: 8kW), a 60kW$_{el}$ proton-exchange membrane fuel cell (PEMFC) operating as a CHP system with approximately 50% thermal efficiency (minimum electric power: 10kW), a heat exchanger connecting the building water circuit with the external fuel cell circuit, a 4'000l buffer tank, and an 11kg H_2 storage tank. The fuel cell is controlled via an electrical output power setpoint (P_{fc}), the heat exchanger via a thermal power setpoint (Q_{hx}) and the heat pump via a compressor speed setpoint (w_{hp}). Weather forecasts, required for the prediction models, were obtained from a weather API with a 15-minute resolution.

The **control layer** consists of three main elements:

1. Cost signals – providing electricity and hydrogen price information.

2. Load forecasts – predicting thermal and fixed electrical load
3. Model Predictive Controller (MPC) – a grid-supportive controller enabling cost-optimal operation while ensuring all demands are met.

These components will be described in more detail in the following section.

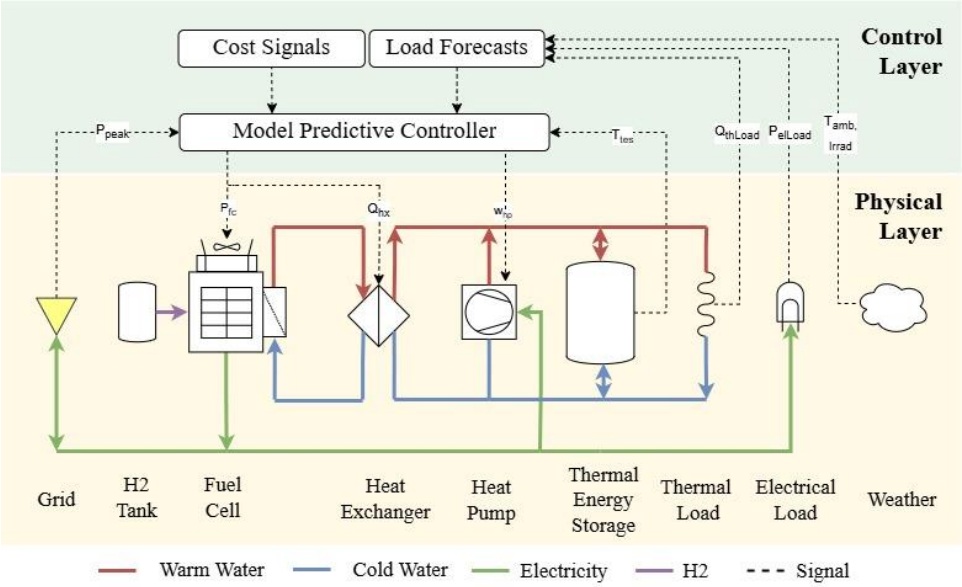


Figure 7 Schematic of NEST, divided into physical and control layers.

2.3.1. Model Predictive Control

Operational optimization relies on an MPC framework to adjust system operations dynamically in response to predicted thermal and electric energy loads, and weather. The MPC runs at a 15-minute resolution, aligning with the billing period of peak power fees. Physical models of the technologies are adopted to anticipate the system responses, similarly to [3].

The MPC algorithm is structured as follows:

- *Decision variables:* Power dispatch for all the energy components depicted in Figure 7, including heat and power from the PEMFC. The decision variables $\mathrm{P_{fc}}$, $\mathrm{Q_{hx}}$ and $\mathrm{w_{hp}}$ are then used as optimal control inputs to the physical system
- *External variables:* Thermal and fixed electrical load forecast. Cost signals such as energy, power and hydrogen tariffs. These variables are described in more detail in Section Load Forecasting and Cost Signals.
- *Constraints:* Non-continuous operational limits and efficiencies for fuel cell and heat pump, TES temperature bounds, thermal and electric energy balance. The average temperature of thermal energy storage was adopted as the only dynamic state.
- *Objective function:* Minimization of the operational cost, including electrical energy, peak power and hydrogen costs for both case studies:
  - *Local - Case Study*:

$$\mathrm{u_{opt}} = \mathrm{argmin}\left(\mathrm{C_{operation}}\right)$$

$$\mathrm{P_{fc}, Q_{hx}, w_{hp}} = \mathrm{argmin}\left(\sum\left(c_{\mathrm{grid,t}} \cdot \mathrm{P_{grid_{NEST},t}} + c_{\mathrm{fc}} \cdot \mathrm{P_{fc,t}}\right) + c_{\mathrm{peak}} \cdot \mathrm{P_{peak_{NEST}}}\right)$$

  - *Global - Case Study*:

$$P_{fc}, Q_{hx}, w_{hp} = \operatorname{argmin} \left(\sum \left(c_{grid,t} \cdot P_{grid_{NEST},t} + c_{fc} \cdot P_{fc,t} \right) + c_{peak} \left(P_{peak_{NEST}} + P_{peak_{Empa}} \right) \right)$$

Where $P_{grid_{NEST}}$ represent the electric power at the NEST connection point, $P_{grid_{Empa}}$ the electric power at the Empa-Campus connection point, P_{fc} the electric power from the fuel cell, P_{peak} is the maximum imported electric power from grid $(\max(P_{grid}))$ over the optimization horizon, c_{grid} the daytime dependent energy tariff, c_{fc} the cost for fuel cell operation and c_{peak} the peak power fee.

The pseudo code for the closed loop operations looks as follows:

Initialize P_{peak}, T_{tes}

1: **for** t = 1 to T **do**

2: **if** t mod dt = 0 **then**

3: Update P_{peak}

3: Read T_{tes}, cost signals, weather forecasts

4: Forecast P_{elLoad}, Q_{thLoad}

5: Solve optimization of MPC

6: Apply optimal control inputs (P_{fc}, Q_{hx}, w_{hp})

2.3.2. Strategy for Peak Shaving

Peak shaving is enforced via the peak power fee included in the objective function. Typically, peak power fees are specified on a monthly basis (CHF/kW/month). While it is theoretically possible to design an MPC with a one-month prediction horizon to capture this behavior, doing so is challenging due to the associated experimental and computational requirements.

To address this, the monthly peak power fee is scaled down to match the shorter prediction horizon used by the MPC. This simplification is valid under the assumption that the ratio between peak power and energy consumption remains constant across both time scales. For this assumption to hold, the prediction horizon should cover at least 24 hours, ensuring that a complete daily load cycle is represented. While a two-day prediction horizon is preferable for peak shaving, allowing the controller to anticipate whether the following day's peak will exceed that of the current day and potentially avoid unnecessary load shifting, it also increases reliance on accurate forecasts over a longer period. This highlights a key trade-off: extended horizons improve decision-making but are more prone to forecast errors. For this proof of concept, we adopt a one-day experiment with a 24-hour prediction horizon to balance control effectiveness and forecast reliability.

2.3.3. Load Forecasting

The forecasting models are built using the deterministic XGBoost framework [9] and trained on one year of historical data. A direct forecasting strategy is employed, where a separate model is trained for each prediction step. The model inputs include historical and forecasted ambient conditions (temperature and irradiance), past load data, and time-based features such as hour of day, day of week, and month. The predictive structure follows:

$$X_{k+n} = f(X_{k-m}, u_{k-m:k+n}, d_{k+n})$$

where X denotes the load, u the control inputs or influencing variables, and d the exogenous conditions at the prediction step.

2.3.4. Cost Signals

All tariffs used as inputs to the controller's objective function are listed in Table 2. The hydrogen cost is an optimistic hypothetical value; the current market price is in the range 10-20CHF/kg [10]. The current market price range was used in Section 2.5 to identify the most suitable setting. The actual peak power fee from the local energy supplier would be significantly lower than the chosen tariff. For the MPC-driven experiments conducted in the project, we selected a hydrogen price and peak power fee within a range that encouraged a meaningful amount of fuel cell operation, enabling conclusions to be drawn about the technical feasibility of PEMFC for peak shaving services and resulting operational patterns. The experiments conducted required low hydrogen price and high peak power fees, mostly due to (i) an unattractive operational pattern for the NEST building demand and (ii) the minimum load constraint for the kvyreen system was too high for optimal peak shaving strategies for the NEST building. Nonetheless, as mentioned, lowering the hydrogen cost and peak power fee allowed us to demonstrate the technical feasibility of MPC-controlled PEMFC. The results for the investigation of most suitable use cases are reported in Section 2.5. The fuel-cell emission factor was derived assuming the hydrogen is produced via electrolysis powered by PV electricity, using a life cycle (embodied) emission factor of 50gCO2/kWh$_{el}$.

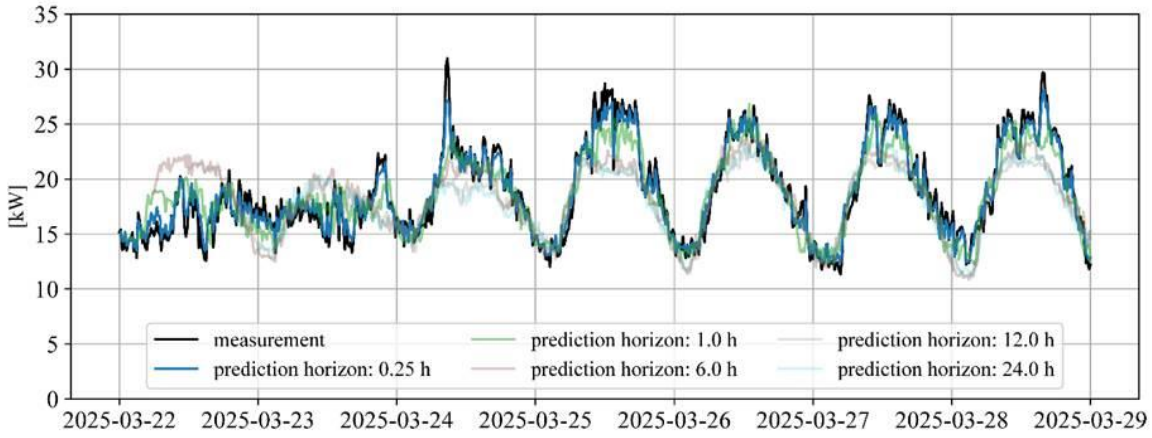
Table 2 Tariffs used as input to the controller [5-8].

Variable	Tariff	Unit	Description
c_{grid}	0.176 / 0.183	CHF/kWh	Electricity prices: night / day (7:00 – 20:00)
c_{peak}	25	CHF/kW/month	Monthly peak power cost
c_{h2}	4.5	CHF/kg	Hydrogen cost
n_{fc}	15	kWh$_{el}$/kg	System charging efficiency
c_{fc}	0.3	CHF/kWh$_{el}$	Fuel cell operation cost (c_{h2} / e_{fc})
e_{grid}	[26, 113]	gCO2/kWh	CO2 Emissions range of electric energy from grid
e_{fc}	109 / 109 (1) 0 / 17 (2)	gCO2/kWh$_{el, th}$	CO2 Emissions of thermal / electric energy from fuel cell ((1) base case; (2) best case)

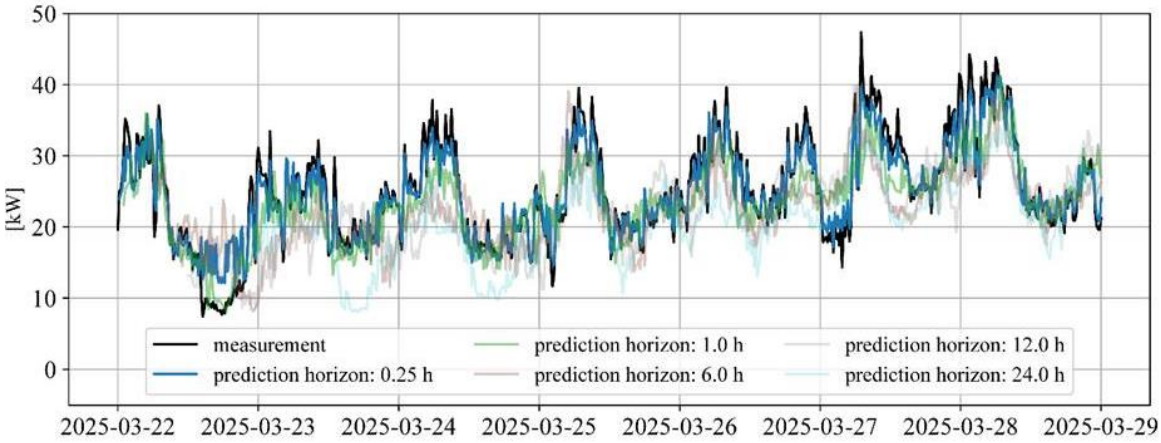
2.4 Results

Load forecasting and implications on controller performance - The time series of load forecasts (Figure 8) and the MAE (Mean Absolute Error) results (Figure 9) show that the XGBoost model can forecast loads accurately up to 24 hours ahead, particularly for fixed electrical loads (uncontrollable loads), with a maximum MAE of 2.5kW, and for thermal loads with a maximum MAE of 5.5kW. The performance of the persistence model and the standard deviation (std) in Figure 4 were added as benchmarks. The time series also indicate that forecasting performance is generally better on weekdays than on weekends, especially for electrical loads, even though time-based features such as the weekday were included in the model.

However, the electrical load forecasts reveal that for horizons greater than one hour, peaks are typically not captured accurately but are instead smoothed out. This is mainly due to the model's objective function, which minimizes the mean error rather than focusing on peak accuracy. This limitation is critical because accurate peak forecasts are essential for the grid-supportive operation strategy: underestimating peaks leads to underestimating fuel cell operation, resulting in progressively higher peak loads, while overestimating peaks causes excessive fuel cell operation. Although the latter keeps electrical peaks low, it is not cost-optimal.



(a) Fixed electrical load forecast



(b) Thermal load forecast

Figure 8 XGBoost load forecasts with prediction horizon 15min – 24h compared with measurements for week of experiments

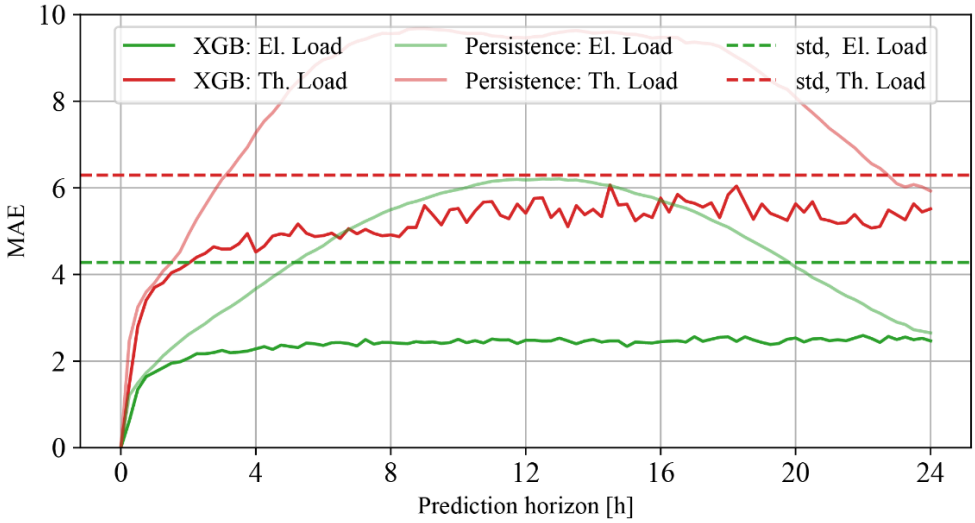


Figure 9 Thermal and fixed electrical load XGBoost and Persistence model performance expressed as MAE (Mean Absolute Error), across different prediction horizons.

Experimental validation of controller – The real-world validation results of the grid-supportive controller are shown in Figure 10. During the experiment, the fuel cell and heat pump were operated so that the measured maximum electrical power over any 15-minute period ($P_{grid,max,measured}$) converged towards the optimal peak power ($P_{grid,max,optimal}$) recomputed by the MPC every 15 minutes, while simultaneously minimizing total operational costs. The observed jumps in the optimal peak power $P_{grid,max,optimal}$ can be attributed to the optimization occasionally failing to converge within the allotted time, resulting in suboptimal solutions.

Since the fixed electrical load is generally low and does not exhibit distinct peaks, the heat pump — with its high minimum power rating of 8kW$_{el}$ and 45kW$_{th}$ — was itself responsible for producing the most pronounced peaks, which were then compensated for by the fuel cell in most cases. This experiment successfully demonstrated the functionality of the control strategy.

Examination of the thermal power output shows that the fuel cell's thermal output fluctuates more than its electrical output, primarily due to the tracking performance of the local lower-level controller.

Experimental validation was conducted only for the Local - Case Study, while the Global - Case Study is presented based on simulations in the following section.

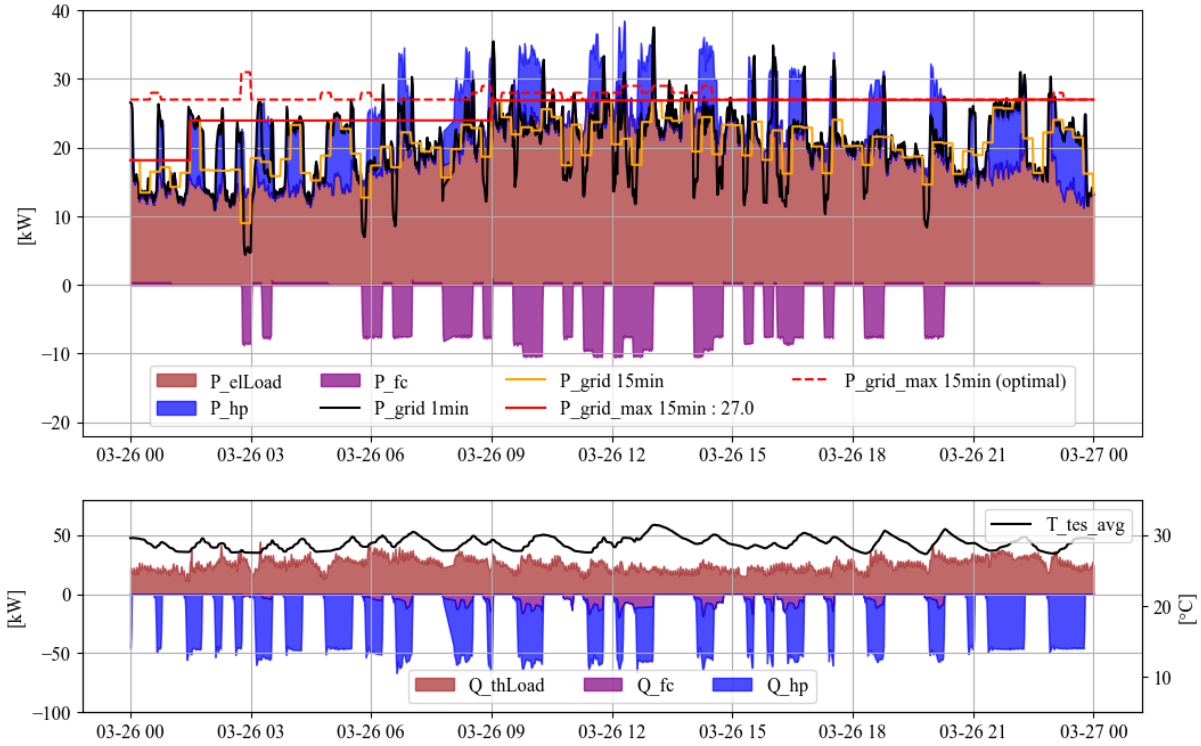


Figure 10 Experimental validation results of grid-supportive MPC-framework aiming to minimize local operational cost (Local – Case Study) - electrical power is depicted in upper graph, thermal power and the thermal energy storage (TES) temperature in the lower graph.

Closed-Loop Simulation Results – The comparison of simulation and experimental results in Figure 11 for the one-day experiments presented in Figure 10 shows a slight overestimation of energy and peak costs in the simulation, while hydrogen consumption is lower, indicating that the fuel cell was activated less frequently.

Table 3 presents closed-loop simulation experiments for both case studies and compares them to the reference operation, where no fuel cell (FC) is present and the heat pump (HP) is operated with a rule-based controller. In the reference case, the HP switches on when the TES temperature falls below a lower threshold and switches off when it reaches an upper threshold.

Regarding the CO2 footprint of H2, two cases were analyzed. Once a base case (1), where hydrogen production from PV is considered and once where a hydro power plan mix is considered.

Results in Table 3 for the Local - Case Study show a total cost reduction of 4% but a total emission increase of 5% compared to the reference case on Campus level. The relatively small cost savings are due to the electrical load profile of NEST, which doesn't have significant peaks. Higher savings could have been achieved in the presence of larger peaks. The increase in emissions results from a higher emission factor for energy from the fuel cell.

In contrast, the Global - Case Study achieves a 15% reduction in total campus operational costs but 18% emission increase. Here, the fuel cell was used to shave both local NEST peaks and campus-wide peaks simultaneously. Although, increased fuel cell operations raised NEST operational costs, it reduced overall Empa-Campus costs. Since the Empa-Campus load profile exhibits more distinct peaks, the potential for savings was greater. As in the Local - Case Study, increased fuel-cell operations led to higher CO_2 emissions.

Conversely, the Hydrogen emissions case 2 results in reduced emissions for Local-Opt (-6% locally and -2% globally as well as with Global-Opt (-13% locally and -4%globally). It is noteworthy that the operational optimization only aims to optimize cost and not operational emissions.

These results clearly demonstrate that the fuel cell has strong potential for grid-supportive operation: the larger the peaks in the load profile, the higher the achievable savings.

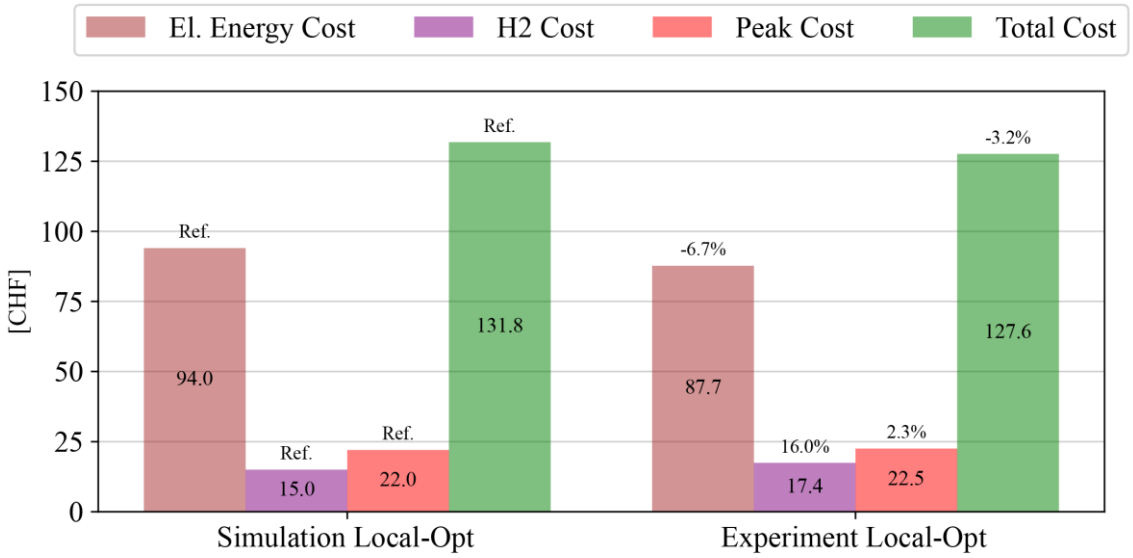


Figure 11 Validation of simulation with experimental results in terms of electrical energy, H2 and peak costs.

Table 3 Comparison of case studies with reference case in simulation for experimental day 26. March 2025. The case focusses on the NEST system boundary. The wider Campus boundary is added to provide context and indicate how the overall system performs, even when only a subset of the Campus optimizes.

	System Boundary	Unit	Reference	Local-Opt	Global-Opt
El. Energy Grid	NEST	kWh	2306	2097 (-10%)	1807 (-22%)
Peak Power	NEST	kW	36.4	26.4 (-28%)	29.2 (-20%)
H2	NEST	kg	0.0	3.4	8.0
Total Cost	NEST	CHF	134	132 (-2%)	141 (+5%)
Total Emissions (1)	NEST	kgCO2	42.4	50.2 (+20%)	61.3 (+48%)
Total Emissions (2)	NEST	kgCO2	42.4	39.8 (-6%)	37.0 (-13%)
El. Energy Grid	Campus	kWh	7939	7730 (-3%)	7438 (-6%)
Peak Power	Campus	kW	121	113 (-7%)	91.4 (-25%)
H2	Campus	kg	0.0	3.4	8.0
Total Cost	Campus	CHF	459	443 (-4%)	411 (-11%)
Total Emissions (1)	Campus	kgCO2	145	152.7 (+6%)	163.8 (+14%)
Total Emissions (2)	Campus	kgCO2	145	142 (-2%)	139 (-4%)

2.5 Aging considerations and techno-economic analysis

The techno-economic analysis and aging considerations relied on a mixed-integer linear programming (MILP) model to optimize the design and operation of multi-energy systems integrating electricity, heat,

and hydrogen technologies. For most of the investigated cases, but for the aging-aware optimizations, the EhubX tool was adopted [11].

While meeting hourly energy demands for a representative year, the objective of the design optimization approach used was to minimize the total annualized cost, composed of (i) energy imports, (ii) annualized capital expenditures, (iii) maintenance costs and (iv) peak power fees. While cost terms (i) to (iii) are typically considered in design optimization problems for energy systems, e.g. [12], [13], cost term (iv) is only rarely accounted for and required dedicated modelling developments. The technical model adopted also considered technology performance, operational constraints, and design constraints such as maximum capacity per technology.

The design problems investigated expanded the baseline case of the NEST pilot by considering ground-sourced heat pump (GSHP), air-sourced heat pump (ASHP), first-life fuel cell (FLFC), second-life fuel cell (SLFC), lithium-ion batteries energy storage (BES), water-based thermal energy storage (TES), H_2 bundles. The listed technologies are the possible ones considered in the design optimization problems, but the optimizer could choose a subset of those if lower total annualized costs could be achieved.

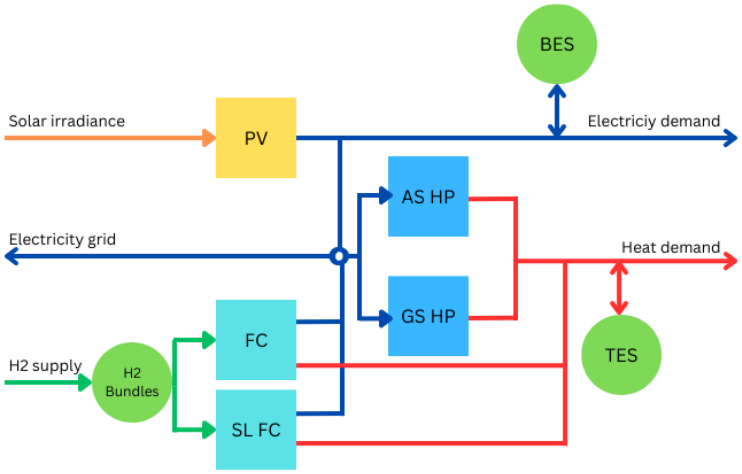


Figure 12 Schematic of the technology candidates and possible connections considered for the techno-economic analysis. For specific energy demands, the adopted optimization routine selects the technology combinations and relative sizes that satisfy demand at minimum cost.

The developed model was validated with the experimental results collected in WP2. To ensure satisfactory fidelity, the electrical system efficiency, initially assumed as 50%, was reduced to 43%, which is representative of the kvyreen system operation at low workloads. Further, the minimum workload constraint for the kvyreen system was modelled for the validation step. Such a constraint is key to replicating the behavior imposed by the MPC strategy. However, the constraint was lifted in the design optimization study as the optimized fuel cell operation considered higher workloads due to optimal sizing of the components.

The results for the comparison are depicted in Figure 13. A 48% overlap in PEMFC activity was found, with the MILP scheduling the fuel cell for 7.6% longer total runtime. Overall, the MILP model overestimates the energy costs for the analyzed period by 12.3%, primarily due to an overestimation of the imported electricity. Such overestimation was mainly attributed to the larger time-step adopted in the design model (hourly) versus the one considered in the MPC (15 minutes). Good agreement was observed for the peak imported power, with only a 1.4% difference.

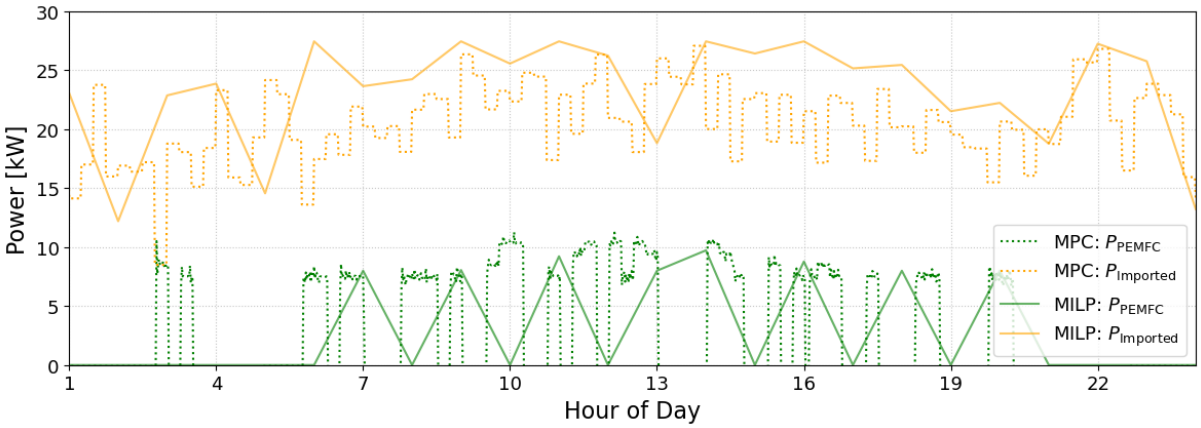


Figure 13 Comparison of the design optimization model (MILP model) with the MPC-driven experimental results for a single day of operation.

In this project, SLFC was consistently identified as a more cost-effective solution than first-life fuel cell (FLFC). The SLFC was assumed as a midlife component with 20'000 hours of operation over 40'000 hours of lifetime. The depreciation for the component was assumed to be linear with its operational hours, which is a conservative assumption compared to typical depreciation trends for energy technologies [14]. Efficiency was considered to scale linearly with the lifetime, with the end of life assumed with a 10% relative reduction in nominal efficiency. The remaining lifetime (20'000 hours) was converted into years, considering operational hours below 600 hours/year, with such a value selected based on the simulation results. Nonetheless, as the resulting value was considered too conservative, a 15-year cut-off was considered based on conversations with the industrial partners. The assumed lifetime was found to have a large impact on the results in the economic profitability of SLFC; future research in the estimation of remaining lifetime for second-life fuel cells is key.

The key inputs to the MILP are reported in Figure 14 and include hourly solar irradiance, heating and electricity demand profiles, energy and fuel costs. Technology parameters are also required, for which reference values are reported in Table 4 and Table 5, respectively for conversion and storage technologies. As these parameters largely influence the optimization results, a global sensitivity analysis using the Morris method was performed to assess the influence of uncertain input parameters on optimal solutions.

For the techno-economic considerations presented in this section, hydrogen was assumed to be supplied in a pressurized tank, similar to the pilot system described in Section 2.3 and consistent with current possibilities in Switzerland. The tank size was included as a decision variable in the optimization, assuming refilling occurs every three days, with a minimum capacity of 12 kg. The CAPEX and OPEX of the pressurized tank were therefore incorporated into the optimization model. The delivery cost of the hydrogen tank was assumed to be included in the hydrogen price, which was varied between 8.3 and 20 CHF/kg. These values are considered representative of realistic hydrogen prices in Switzerland according to [10].

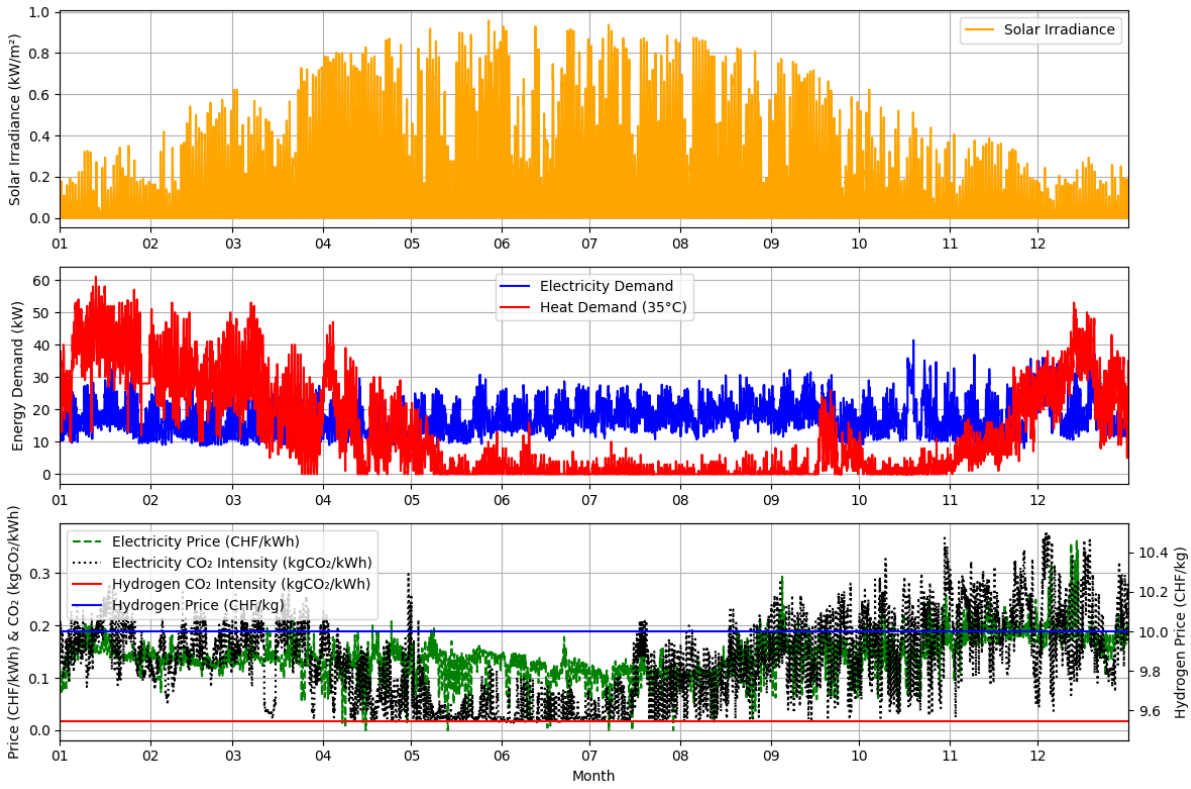


Figure 14 Dynamic and static boundary conditions for the baseline design optimization approach used for the techno-economic analysis. Most of the depicted parameters were varied in global and dedicated sensitivity analysis, as detailed in the next subsections.

Table 4. Technology parameters for conversion technologies. A selected number of these parameters varied as part of the sensitivity analysis detailed in the next subsections.

Parameter	**Units**	**PV**	**FLFC**	**SLFC**	**GSHP**	**ASHP**
Lifetime	years	25	15	15	20	20
CAPEX fixed	CHF	1'075	23'730	11'865	22'000	17'000
CAPEX per cap	CHF/kW (*) and CHF/m²	280(*)	1'975	987.5	2'180	1'330
OPEX per cap	CHF/kW/year	2.6	72	72	6	6
η_{el}	-	0.17	0.425	0.404	-	-
η_{th}	-	-	0.425	0.404	-	-
COP	-	-	-	-	3.8	2.8

Table 5 Technology parameters for storage technologies.

Parameter	Units	BES	TES	H_2 bundles
Lifetime	years	10	30	50
CAPEX fixed	CHF	1'600	153	800
CAPEX per cap	CHF/kWh	750	76	17.1
OPEX per cap	CHF/kWh/year	0.0	0.16	0.16
η_{in}	–	0.95	0.95	0.95
η_{out}	–	0.95	0.95	0.99
SOC_{min}	–	0.2	0.0	0.05
SOC_{max}	–	0.8	1.0	1.0
Self-discharge	–/hour	0.0042	0.01	0.0

The design optimization model was used to optimize the design for the NEST pilot, and fuel cells were not selected as part of the optimal technology asset. This is due mainly to the absence of large winter peaks in NEST's energy demand and to the small scale of the demand. The identification of the most suitable business cases for decentralized peak shaving by fuel cells was conducted by means of a sensitivity analysis, as presented in the next subsections.

Additional results regarding the techno-economic analysis of fuel cells for peak shaving can be found in [15-17], which were developed during the project.

2.5.0. Demand profile screening

Energy demands for residential and tertiary buildings from the JASM dataset [18] were considered. This includes demand profiles for single-family houses (SFH), multi-family houses (MFH), hospitals, schools, restaurants, shops, and offices. **To isolate the effect of the temporal distribution of the energy load, the annual equivalent electricity demand, defined as the annual electricity demand plus the annual heating demand divided by COP=3.5, was fixed.** The annual equivalent electricity demand was used for normalization instead of the electricity demand to include the impact of heat pump demand on the imported electricity and ensure a fair scaling of the curves.

The results of the analysis are summarized in Figure 15. The optimization results highlight clear patterns in technology selection across different building demand profiles. Air-source heat pumps (ASHP) are consistently adopted in all profiles due to their favorable cost-performance trade-off, while ground-source heat pumps (GSHP) are never selected. This is attributed to their lower investment costs and the simplified performance modeling without seasonal COP variation, which could otherwise favor GSHP in winter-dominated demand profiles.

Photovoltaic (PV) adoption strongly correlates with daytime demand: schools and offices, characterized by higher loads during daylight hours, exhibit larger PV capacities, reflecting the economic benefit of self-consumption. Storage and dispatchable technologies reveal more distinct differences. Thermal energy storage (TES) is consistently chosen when heating demand is present, supporting temporal decoupling of heat generation. Battery energy storage (BES) and fuel cells (FC) never appear together, confirming they serve similar peak-shaving roles. BES is preferred for profiles with frequent but moderate electrical peaks, such as in multi-family houses (MFH), where load regularity enhances economic viability. The BES charges during low-demand periods and discharges almost daily to smooth peak loads, benefiting from the regular daily pattern. Conversely, in the school and restaurant cases, the SLFC is deployed for peak shaving under less frequent but more pronounced peaks, primarily driven by space heating during the coldest days and limited PV availability. This demonstrates its suitability for infrequent yet high-magnitude peak events. Finally, hospitals were identified as unsuitable use cases for peak-shaving technologies at the considered scale due to their relatively flat energy demand throughout the year and limited intra-day fluctuations.

In the next subsections, the energy demand profiles for schools are considered.

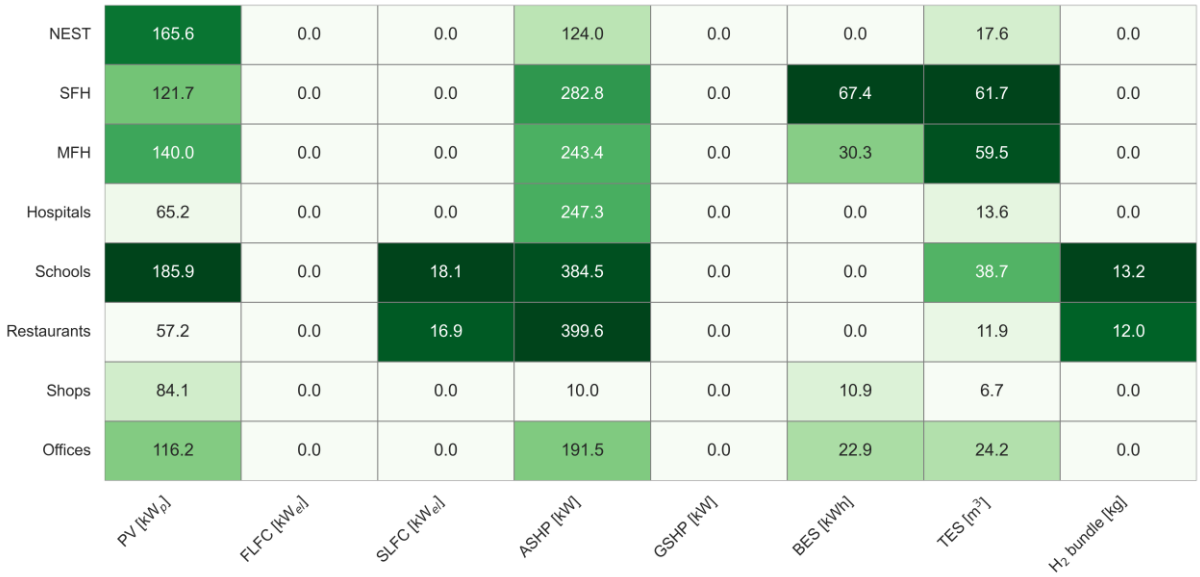


Figure 15 Optimal sizing of the technologies considered for different energy demand profiles. The demands were normalized for an annual equivalent electricity demand of 500MWh/year.
SFH: single-family house, MFH: multi-family house, PV: photovoltaic, FLFC: first-life fuel cell, SLFC: second-life fuel cell, ASHP: air-sourced heat pump, GSHP: ground-sourced heat pump, BES: battery energy storage, TES: thermal energy storage.

2.5.1. Impact of energy costs and technology parameters

The impact of energy costs and technology parameters was analyzed by means of a global sensitivity analysis by the Morris Method, similarly to [12].

Table 6 List of selected parameters and respective ranges used in the global sensitivity analysis.

Parameter	**Range / Variation**
Electricity import cost	0.15-0.30CHF/kWh
Hydrogen price	8.3-20.0CHF/kg
Peak power fee	0-30CHF/$kW_{peak,month}$
CAPEX: Air Source (AS) HP, Ground Source (GS) HP	±20%
CAPEX: FC, Second-life (SL) FC, H_2 bundles	±50%
Lifetime: FC, SL FC	±50%

The ranking for the most influential parameters on the optimal sizing of SLFC can be observed in Figure 16. Interestingly, **for the price ranges explored, the H_2 price was not identified as the most influential parameter**. This is due to the price ranges explored, for which H_2 cost was always higher than its equivalent electricity and heating costs, leading to very few scenarios in which fuel cells were used for base load. The use of fuel cells to cover medium to high shares of the heating demand was found only in scenarios in which a higher CAPEX for capacity was assumed for heat pumps. However, such a parameter is hardly foreseen to increase in the future. Influential parameters were instead identified in the CAPEX per capacity and lifetime for the SLFC technology. That is, reducing investment costs for FC is key to ensuring their economic profitability as decentralized peak shaving technology.

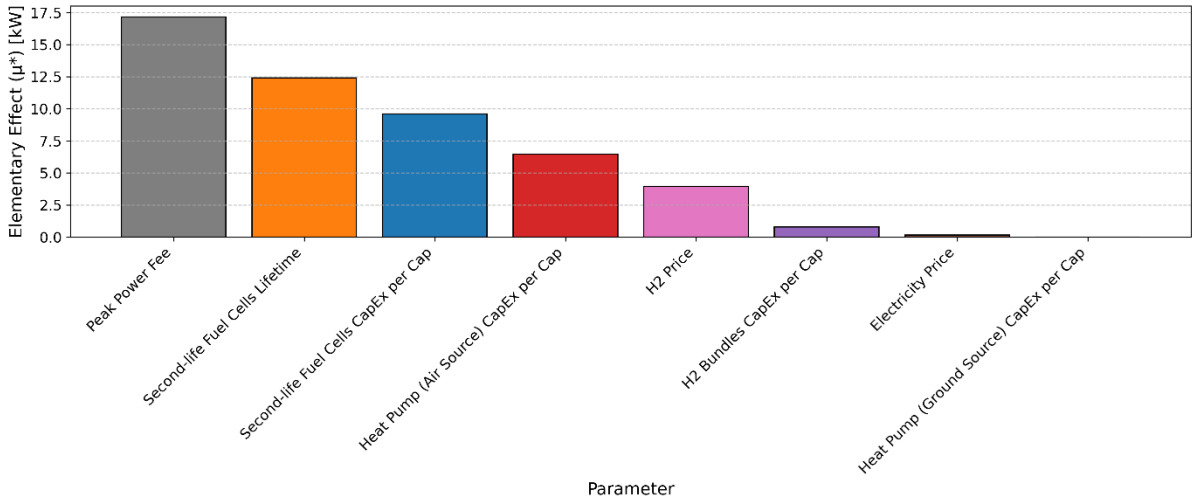


Figure 16 Results of global sensitivity analysis by Morris Method depicting the ranking for the influence of selected design parameters on the optimal sizing of second-life fuel cells.

Peak power fees were identified as the most influential parameter for the fuel cells sizing and were also found to have a large impact on the total annualized cost. The impact of the peak power fee on the optimal sizing of SLFC and TAC of the system is reported in Table 7. The first SLFC installation appears at a fee of 18CHF/kW_{peak}, with capacity increasing at higher fee levels, albeit in a non-linear manner. This non-linearity reflects a threshold effect, where SLFC become competitive only above a certain peak power fee, and diminishing returns, since their economic benefit is limited by the small number of hours in which they operate. For the TAC, the rate of cost increase gradually declines once SLFC are introduced. This trend is explained by the onset of peak shaving from 18CHF/kW onwards, where SLFC operation begins to offset peak power charges. Below this threshold, peak shaving is provided entirely by other flexibility options, such as strategic HP dispatch and TES utilization.

Table 7 Impact of peak power fee on the optimal sizing of SLFC and TAC.

Peak Power Fee [CHF/kW_{peak}]	Installed capacity of SLFC [kW]	Total Annualized Cost [kCHF/year]
0	0	136.6
10	0	152.0
18	17	164.2
20	18	166.8
30	24	179.6

Interestingly, the qualitative global sensitivity analysis conducted using the Morris method did not indicate a strong influence of hydrogen cost on the optimal size of SLFC. To further investigate this finding, additional local sensitivity analyses were performed focusing on the hydrogen cost, peak power fee, SLFC CAPEX per capacity, and electricity cost. The results are summarized in Figures Figure 17 and Figure 18.

Across all scenarios, the installed SLFC capacity remains relatively small compared with the overall system size. This is because the SLFC primarily provides peak-shaving services rather than base-load operation. Consequently, the peak power fee exerts the largest influence on the system's economics. SLFC units are installed only when a peak power fee is present, irrespective of other parameter

variations. For instance, even in the most favorable conditions for hydrogen technologies, such as a hydrogen price of 8.3 CHF/kg and an electricity cost of 0.3 CHF/kWh, no SLFC is installed if the peak power fee is null. This outcome highlights that, under current and near-future cost assumptions, producing electricity and heat through SLFCs remains more expensive than supplying the same services through the grid and heat pumps.

For peak power fees of 30 CHF/kW_{peak}, which exceed current levels but may be considered realistic under future tariff structures reflecting grid congestion costs, SLFC deployment becomes economically favorable across all tested conditions. **When the peak power fee is 20 CHF/kW_{peak}, the cost-effectiveness of SLFCs becomes sensitive to both hydrogen price and capital cost. Hydrogen prices above ≈ 11 CHF/kg and specific investment costs above ≈ 1,200 CHF/kW limit their profitability. Conversely, for the electricity price range considered (0.15 to 0.3 CHF/kWh), the impact on the optimal SLFC size is minor.**

These additional results reinforce that grid-related incentives (peak power fees) are the main driver for the adoption of SLFC systems, whereas the effect of hydrogen price and CAPEX emerges only within specific cost intervals.

The apparent discrepancy between the global (Morris method) and local sensitivity analyses can be explained by their different natures: the Morris method explores a broad parameter space and averages effects over many combinations, often diluting localized dependencies, whereas the local analysis isolates the influence of each variable around representative operating conditions. As a result, the hydrogen price appears to have a more significant impact in the local analysis, where the system's feasibility boundary is explicitly defined.

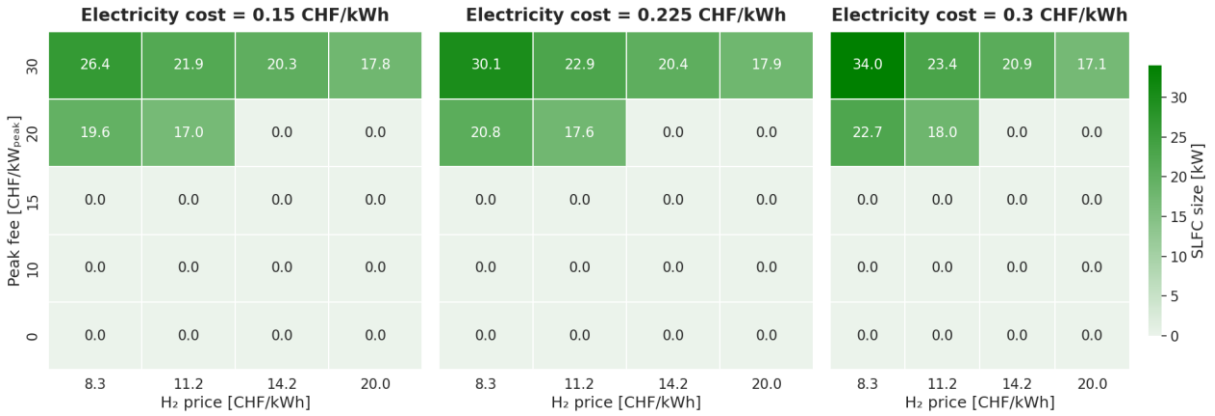
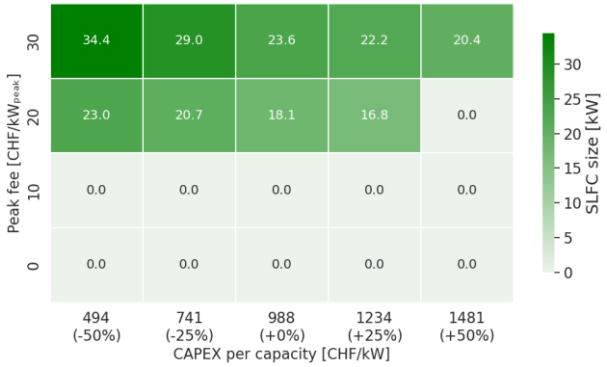


Figure 17 Impact of peak power fee, electricity cost, and H2 price on the optimal SLFC size.



2.5.2.Figure 18 Effect of CAPEX and Peak Fee on SLFC size.Impact of demand size

The annual equivalent electricity demand was varied, and the optimal sizing of BES and SLFC is reported in Table 8. It can be observed that **below a certain threshold, a small-sized BES is preferred over SLFC.** This indicates that a minimum demand scale is required for SLFC to become cost-optimal due to the relatively high fixed CAPEX. Additionally, the installed capacities for both BES and SLFC increase linearly with the total annual equivalent electricity demand. For the annual equivalent electricity demand range explored (up to 2'000MWh/year), the optimal SLFC size is only 24kW, which is lower than the typical sizes of FC for vehicle applications, which typically range from 60 to 100kW.

Table 8 Impact of annual equivalent electricity demand on installed capacities of BES and SLFC.

Annual Equivalent Electricity Demand [MWh/year]	Installed capacity of BES [kWh]	Installed capacity of SLFC [kW]
100.0	0.6	0.0
200.0	1.2	0.0
500.0	0.0	18.0
1'000.0	0.0	36.0
2'000.0	0.0	72.0

The installed capacities of peak-shaving technologies under different space heating demand sizes are reported in Table 9. Such different demands are obtained by scaling the baseline space heating demand by a factor of 0.5 and 2.0, representing, respectively, a warmer and cooler climate. All other assumptions (including solar availability) and input were unvaried compared to the baseline scenario of Schools with a 500MWh/year of annual equivalent electricity demand. As expected, **the fuel cell optimal size increases in cooler climates,** driven by higher HP capacities and the associated rise in winter electricity demand, which amplifies the economic value of peak shaving. In contrast, the warmer climate scenario sees no SLFC deployment, as the reduced heating demand lowers both peak magnitude and seasonal variability, diminishing their cost-effectiveness. In this case, a small BES is installed instead, indicating that limited peak shaving with battery storage is marginally more economical than relying solely on operational flexibility from HP and TES.

Table 9 Installed capacities of peak shaving technologies across climate scenarios.

Space heating demand factor	Installed capacity of BES [kWh]	Installed capacity of SLFC [kW]
0 (Dübendorf)	0.0	18.0
x0.5 (Warmer)	3.0	0.0
x2 (Cooler)	0.0	29.0

2.5.3. Grid reinforcement savings estimation

The monthly maximum power drawn form the grid for schools with and without SLFC are compared in Figure 19. The inclusion of SLFC consistently reduces monthly peaks, with the largest reductions observed in winter, when both electricity and heating demands are high. Although strong heating demand primarily drives the economic viability of SLFC, once installed, they are operated in almost every month of the year, except in July, when high PV generation and low demand in schools limit their use.

Saving in grid reinforcement cost can also be estimated by calculating the avoided transformer capacity due to the peak shaving provided by the SLFC. Specifically, the annual peak electricity import decreases from 235.5 to 212.7kW, representing a reduction of 22.8kW. Assuming a transformer cost per capacity of 62.5CHF/kW, this leads to savings of 1'425CHF for the DSO in terms of investment cost reduction for the transformer size decrease. From the consumer side, i.e., the CHP system owner, the annual operating costs, including electricity purchase and peak power fees, are reduced by about 1.5 % compared to scenarios without the SLFC. In summary, the optimal operation of the SLFC leads to both infrastructure cost reductions for the DSO and operational cost savings for the consumer.

It is important to note that the optimality of SLFC (in terms of consumer cost reduction) is often marginal. For example, the adoption of FLFC instead of SLFC, the TAC would increase by 2.8kCHF/year, with FLFC not being part of the optimal solution. If only FLFC is available, the optimal design entails the installation of a 3kWh BES for peak shaving purposes. Additionally, if the energy system capacities were selected without considering a peak power fee, i.e., assuming 0CHF/kW, and then fixed while optimizing operation with higher peak power associated fees, e.g., 20CHF/kW, the TAC increases by only 0.5kCHF/year.

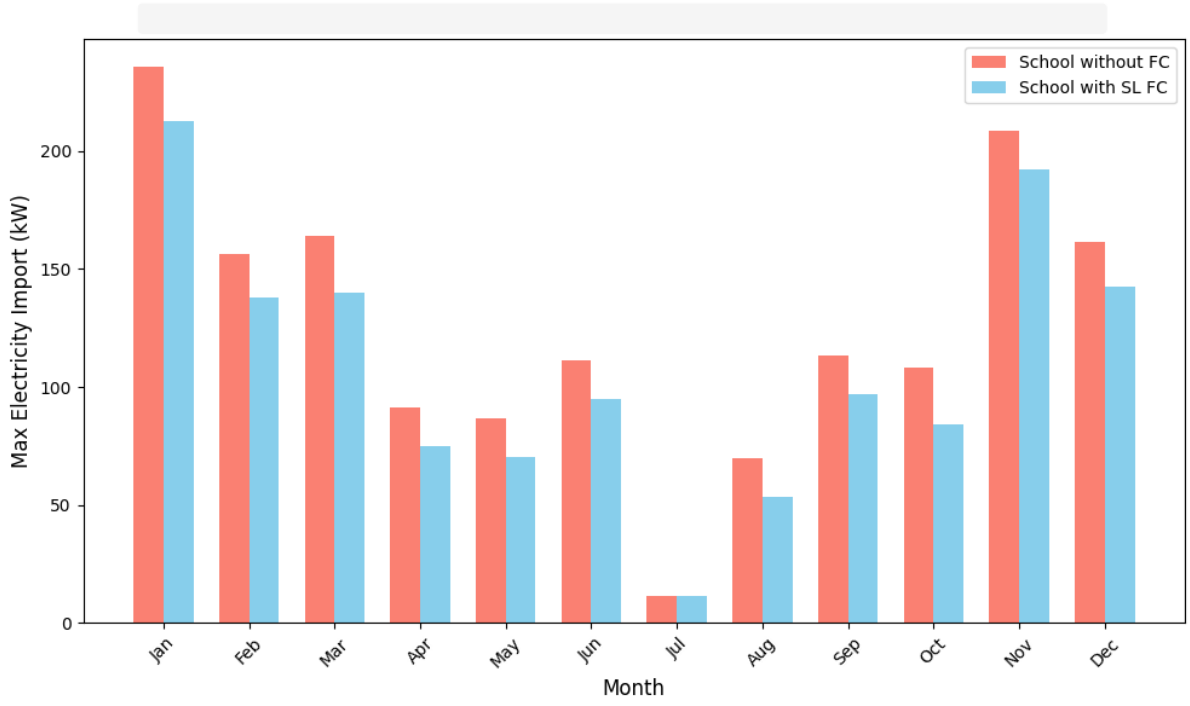


Figure 19 Monthly peak electricity import with and without SLFC. The analysis considered energy demand profiles of schools with annual equivalent electricity demands of 500MWh/year.

2.5.4. Aging-aware design optimization

A fuel cell is degrading over its lifetime, which results in a shift from electrical to thermal power output taking place. In a first assumption, for fuel cells to be used in a CHP-application where electrical and thermal power is used, even a degraded fuel cell, up to a certain extent, can create added value. So, second life applications of fuel cells, which originally were used in automotive applications for a certain

period of time are afterwards transferred in a CHP-application for buildings seem viable. This reduces the system cost and extends the lifetime of fuel cells.

WP3 of the H2-districts project investigated the impact of degradation on the optimal operation and design of a PEMFC. To achieve such a goal, first, the key drivers for the degradation of PEMFC were analyzed based on literature studies and models. Overall, the lifetime of PEMFC was defined as the calendar time for which the electrical efficiency was reduced by 10% of its nominal value at the beginning of life (BoL). That is, for a PEMFC with nominal efficiency at BoL of 50%, its lifetime is considered as the calendar time for which, given a specific operational pattern, the PEMFC drops below 45%.

An operational pattern for PEMFC technologies used for base load (operational hours > 5'000h/year) was derived by means of a MILP approach for low hydrogen prices. The degradation models from [19-20] were adopted to study the key drivers for degradation. The following key conclusions were derived from this analysis:

i. High Power Operation accounts for almost 80% of the estimated total degradation rate and was, therefore, identified as the main driver for degradation. The High-Power Operation can be considered a function of the operational hours of the PEMFC.

ii. Low Power Operation and Loading Operation can be disregarded due to their low impact on degradation rate.

iii. The impact of Start/Stop accounts for around 20% of the degradation rate. However, in order to reduce the computational effort of the design tools to be tested, it was decided to neglect the impact of Start/Stop on the estimated degradation.

iv. Degradation models developed for vehicle applications appear to lead to conservative estimations of lifetime for PEMFC used for stationary applications.

Following the analysis of the key drivers for degradation, a degradation-aware optimization model was developed that considered the effect of aging to be dictated by the number of operational hours. To ensure linearity, the same degradation impact was considered regardless of the FC partial workload. While this assumption must be carefully verified when dealing with optimal operation of FC systems, it was found to have only a marginal impact on the sizing choices.

The results obtained by means of the integration of a degradation-aware model in a MILP design tool are reported in Figure 20 and Figure 21. The results presented deal with a design case with significant use of the PEMFC (capacity factor up to 52%). Degradation significantly affects the optimization results, with PEMFC not installed if planning horizons larger than 2 years are considered. The impact of degradation is instead not fully captured when planning horizons of 1 year are considered, as typically done in literature, e.g. [12]. However, as shown in Figure 21, the optimal fuel cell size increases by ≈10% when combined heat and power (CHP) is considered. That is, the profitability of CHP is enhanced by the degradation effect, as the thermal efficiency increases. Additional results can be found in [21] which were developed as part of the project.

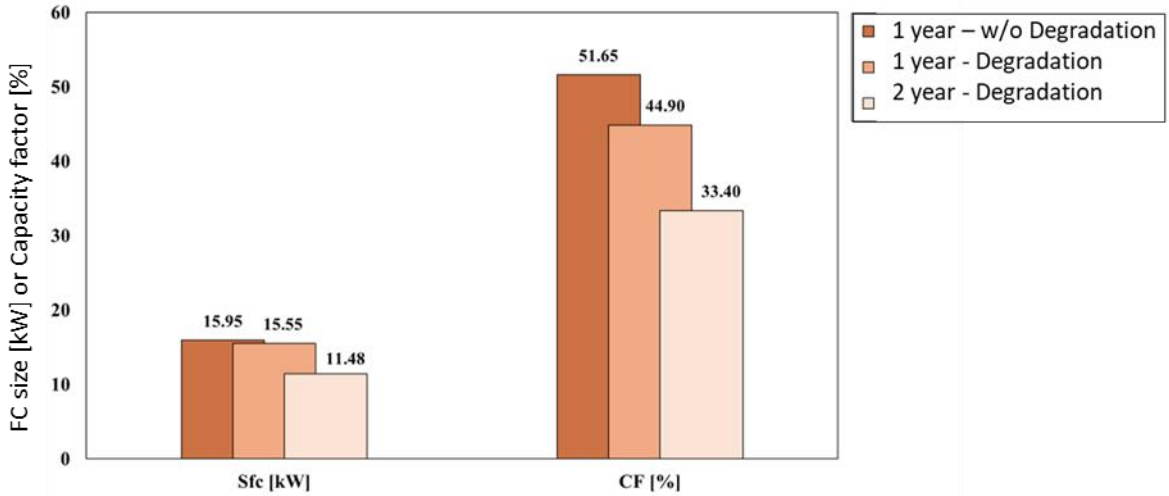


Figure 20 Impact of degradation effect and planning horizon on the optimal size of the fuel cell, S_{FC}, and the optimal capacity factor, CF. The fuel cell size reduces when degradation effects are included, and optimal size significantly reduces if longer planning horizons are considered.

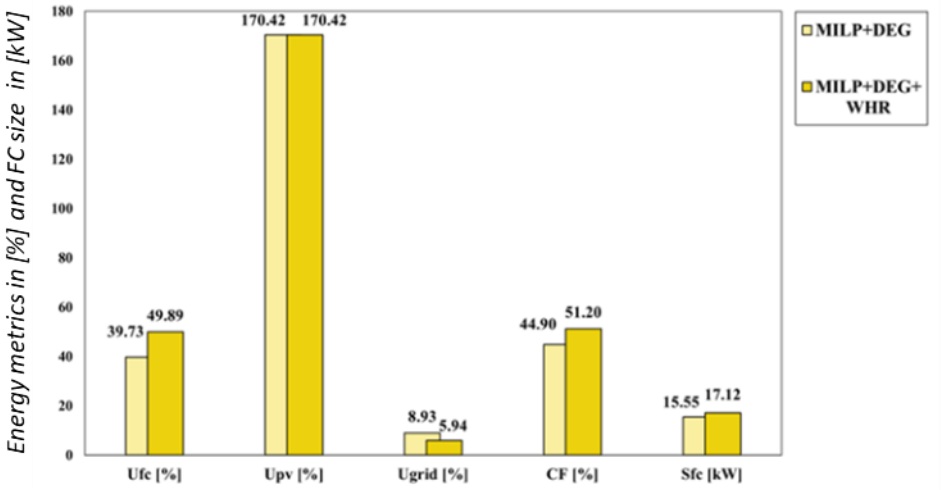


Figure 21 Impact of waste heat recovery on selected energy metrics, including the optimal size of the fuel cell, S_{FC}. Considering waste heat recovery leads to larger optimal sizes for the PEMFC (+10%).

Ufc = Efc / Eload; Upv = Epv / Eload; Ugrid = Egrid/Eload.

3 Conclusions and outlook

The H2-districts project developed and provided relevant results while conducting the respective work packages. In this chapter, challenges, and subsequent conclusion are listed, additionally an outlook is given on future activities, disseminations on the project.

3.1 Challenges and Conclusions

(1) *Pilot system installation* - The successful implementation of the kvyreen system and integration into the NEST+move demonstrators was not challenging. The kvyreen system operation was smooth with minimal technical issues. However, having the building permits took longer than expected and should be taken into account during the planning phase involving hydrogen technologies. When hydrogen in building applications become more common, permission processes will be more standardized, and local authorities will also get accustomed to this.

(2) *Steps towards a real life operational control scheme* - The employed control scheme on the pilot was a rather complex model predictive controller (MPC), which operates at a 15min resolution and aims at predicting demands and utilizing the system to its fullest to satisfy them optimally. However, as a first rollout step, a more rule based scheme, which acts continuously, able to better utilize the fast (<3min) FC dynamics and is simpler in implementation and maintenance, could be more viable as commercial rollout product.

(3) *Grid-supporting control* - Applying optimal control to the energy system proved challenging for three main reasons: (i) System complexity – The integration of multiple technologies and numerous measurement points, together with the need for extensive tuning of lower-level controllers, substantially increased implementation difficulty. (ii) Forecasting limitations – Accurate peak prediction remained difficult despite abundant training data and the use of advanced ML frameworks. Inaccurate forecasts led to suboptimal fuel cell operation, missed savings opportunities, and, in some cases, increased energy costs. (iii) Flat electric load profile – The relatively shallow load curve at NEST limited the peak shaving potential.
As a result of these three factors, the economic benefit of peak shaving in the NEST case study was small, even under optimistic tariff assumptions.

(4) *Grid-supporting control* - The peak shaving strategy in this study was evaluated for a one-day billing period. Extending the methodology to longer billing periods would increase the scope for globally optimal operational planning, but it would also amplify the impact of forecasting errors. In peak shaving applications, there is a fundamental trade-off between forecast accuracy and the scope of optimization: short-term forecasts are typically more accurate, benefiting solver performance, but cover only limited planning horizons. Longer horizons can in principle yield better overall schedules, yet their reduced forecast accuracy can sharply compromise effectiveness, further lowering economic benefits and, in some cases, even increasing operational costs.

(5) *Grid-supporting control* - Fuel cells can serve multiple purposes and address several peak events, as demonstrated in the simulation results for the Empa campus. This versatility increases the leverage of a fuel cell investment, potentially shortening the return-on-investment period. Most likely, a significant economic added value for such peak shaving system is not only created by best prediction of the load but by the capability of fastest activation also. Local power reserve for primary, secondary and tertiary grid stabilization (dt. 'Systemdienlichkeit'), including the flexible capability for apparent power compensation, will represent a very crucial element in future energy systems.

(6) *Techno-economic* analysis - Use cases with strong seasonality in energy demand, such as schools and restaurants, were identified as the most suitable business cases for fuel cells for peak shaving. In the design optimization cases explored, fuel cells were installed in instances where large heat pumps were present, to allow for peak shaving during winter months, which is hard to achieve with battery technologies or other means of flexibility. Nonetheless, when

installed, fuel cells were predicted to operate also outside of winter months, but with limited total operational hours, below 600 hours/year. This limited operational time entails a relatively long lifetime, which is key in enhancing their economic viability.

(7) *Techno-economic* analysis - The installation and optimal operation of fuel cells in combination with air-sourced Heat-Pumps consistently reduce monthly peaks, with the largest reductions observed in winter, when both electricity and heating demands are high. For an investigated case with schools, the annual peak electricity import decreased from 235.5 to 212.7kW, leading to savings of 1'425CHF in transformer installation costs. For the consumer, the annual operating costs were reduced by 1.5%.

(8) *Aging considerations* - Aging plays a role in design optimization where fuel cells cover the base load, while it only plays a marginal role in design decision-making problems when fuel cells are used for peak shaving. When Fuel cells are used to cover base load, the optimal sizing is impacted with reductions of up to 28%. However, these effects can be captured only if multiple years are considered and not only with 'single year planning horizons' (as typically done in energy system optimization problems). Degradation is beneficial to a CHP-Application. If CHP is considered, the optimal PEMFC sizes are increased by 10%.

(9) Lack of data and insights on second-life fuel cells – the techno-economic analysis conducted in WP4 identified scenarios for which second-life fuel cells are cost-effective solutions for peak shaving in small-scale districts. However, since the application of fuel cells in daily operation such as for example cars and heavy-duty trucks is still very limited, the number of available fuel cells which reached their end-of-life in these applications is small and only limited experience exists. For this reason some of the assumptions made to model second-life fuel cells, such as depreciation and remaining lifetime (Section 2.5), need to be carefully verified, as limited insights were found in the literature regarding second-life fuel cells.

(10) Long-term Profitability of such a Peak-Shaving-System – The biggest uncertainty is within the estimation of the economic added value which could be created with such a system. Long-term profitability, in particular, will depend crucially on future CO_2 charges, electricity tariffs, demand charges, and cost savings resulting from avoiding grid expansion. Furthermore, it is conceivable that revenues from system services (dt. 'Systemdienstleistungen') will also make a significant contribution to profitability in the future.

(11) Replicability: The analysis indicates that the economic viability of FC-CHP systems based on second-life fuel cells is primarily driven by optimal operational strategies and the presence of peak power fees. Under realistic near-term conditions, hydrogen prices around 11 CHF/kg and technology costs of about 1,200 CHF/kW, such systems can already achieve profitability when used for peak-shaving services. These boundary conditions are compatible with hydrogen delivered via trailers and stored in small-scale bundles, as demonstrated in the pilot setup, suggesting that the concept does not rely on a large-scale pipeline infrastructure. Hence, while the widespread deployment of FC-CHPs in Switzerland will depend on the regional availability and cost of hydrogen, the results show that localized and modular implementations can be economically viable within emerging grid tariff schemes, supporting their replicability in other Swiss contexts and comparable energy systems.

3.2 Outlook

3.2.1. Topical outlook

As outlined in [3], the foreseeable widespread use of air-sourced heat pumps will lead to significant grid overloads. In addition, by importing electricity in winter and the measures currently discussed in Switzerland to ensure a secure electricity supply in winter will also lead to increased CO_2 emissions. Within this project, an integrated energy system consisting of local storage with renewable hydrogen, fuel cells,

heat pumps, charging stations, PV, etc. was installed and the concept was tested for peak shaving of grid demand and for reducing overall CO_2-Emissions. As the results of the project demonstrate, such a concept can help to solve the aforementioned problems.

It has therefore a significant potential for multiplication in communities, neighborhoods, and areas with similar challenges in heat and electricity supply. The concept can be directly transferred, particularly to regions with limited grid capacity and a high demand for decentralized energy supply. With regard to the supply of renewable hydrogen, it is foreseeable that over the years an increasing proportion of the hydrogen used will be secured through imports, transported to Switzerland via pipeline systems and generated primarily from renewable electricity from wind power and PV. The technologies and components used – hydrogen fuel cells, heat pumps and PV systems – are modularly scalable and can be economically implemented in other municipalities directly or through energy contracting business models.

A key element for reliable and resource-optimized operation will be the data-based control and operation of individual local plants. By permanently collecting and analyzing the operating data in the various regions, the entire value chain consisting of renewable electricity, renewable hydrogen, its storage and logistics and its ultimate use in buildings, can be significantly optimized.

3.2.2. Pilot outlook

Since Sept. 2021 the kvyreen prototype was used as development platform for e-mobility (as power source for fast charging of battery-electric vehicles) and for buildings, as described in this report. After this project is finished, it will be refurbished and will be installed at the new Campus of ZHAW in Winterthur. There it will serve as a hydrogen powered generator, including the full integration into the electrical and thermal network, for the education of students and for further research work.

Another outcome of this project is the adaptation of the current series-product kvyreen k80/160 GS (Generator with 400V, 3Ph, 50Hz outlet) for building applications. This will include a version with an optional plate-heat-exchanger to transfer it to buildings and districts. This version will be added to the product-family 'kvyreen' and will use the basic technology, equipment and software control for building applications also.

3.2.3. Research outlook

The results of the H2districts project will provide valuable input to the SWEET PATHFNDR project in several ways:

(i) the experimental data and updated technology parameters collected in H2districts will enhance the accuracy and reliability of future numerical studies;

(ii) The findings from H2districts will serve as practical evidence for the technical feasibility of decentralized fuel cell solutions to reduce grid stress and support local peak shaving and promote sector coupling via waste heat recovery;

(iii) Key insights will be summarized and integrated into the technology explainers currently being developed within PATHFNDR.

Further, the site-level results highlight the importance of studying the role of peak power fees at cantonal and national levels, in order to assess their impact on grid operation and to identify which technologies can most effectively contribute to energy savings and system flexibility. A follow-up study on wider resilience contributions and ancillary services contributions by decentral FC's would be an interesting future research direction.

4 National and international cooperation

- Three master thesis students and one semester project student, whose results contributed to the H2-districts project, were co-supervised with ETH and with the Politecnico di Torino (Italy). The list of master's theses and final reports is reported in Section 5.
- Media event in March 2025 showing the pilot installation in operation, presenting preliminary results and their relevance for stakeholders from industry, regulators and journalists.
- Gebäude Klima Schweiz, participation in the working group 'Brennwert Technik'
- Paticipation in "Round Table: Gebäudetechnik 2025' presenting the h2-districts concept
- Around a dozen Visits/Guided Tours with potential commercialization partners
  - Several companies for engineering and planning of heating/ventilation/air-conditioning systems
  - Toyota Europe for the application of fuel cells in buildings

5 Publications and other communications

Peer-reviewed Publications and conferences

Description: brief description of the outputs.
Impact of peak power fees on the design and operation of energy systems Humbert G.; Brandes M.; Pellaz L.; Peter Ch.; Heer Ph., CISBAT 2025, Accepted
Economic Potential of Waste Heat Recovery from Hydrogen Technologies in Energy Communities, Decormis A, Humbert G, Cai H, to be submitted to Advances in Applied Energy
The Role of Peak Power Fees in the Optimal Design of Hydrogen-Sourced Fuel Cells, Humbert G, Pellaz L, Brandes M, Heer P, to be submitted to International Journal of Hydrogen Energy

Master thesis projects

Description: brief description of the outputs.
Decormis Leon Andres, *Dynamic pricing of waste heat recovered from hydrogen technologies in a multi-energy district*, January 2025. Supervised in collaboration with ETH in the framework of H2-districts and Nanoverbund projects.
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