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Conditions for profitable operation of P2X energy hubs to meet local demand with energy market access

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ABSTRACT

This paper analyzes the operation of an energy hub on a community level with an integrated P2X facility and with access to energy markets. In our case, P2X allows converting power to hydrogen, heat, methane, or back to power. We consider the energy hub as a large prosumer who can be both a producer and consumer in the markets with the novelty that P2X technology is available. We investigate how such a P2X energy hub trades optimally in the electricity market and satisfies local energy demand under the assumption of a long-term strong climate scenario in year 2050. For numerical analysis, a case study of a mountain village in Switzerland is used. One of the main contributions of this paper is to quantify key conditions for profitable operations of such a P2X energy hub. In particular, the analysis includes impacts of influencing factors on profits and operational patterns in terms of different degrees of self-sufficiency and different availability of local renewable resources. Moreover, the access to real-time wholesale market electricity price signals and a future retail hydrogen market is assessed. The key factors for the successful operation of a P2X energy hub are identified to be sufficient local renewable resources and access to a retail market of hydrogen. The results also show that the P2X operation leads to an increased deployment of local renewables, especially in the case of low initial deployment; on the other hand, seasonal storage plays a subordinated role. Additionally, P2X lowers for the community the wholesale electricity market trading volumes.

1. Introduction

Current greenhouse gas emissions targets for the energy sector envisage net-zero CO_2 emissions by 2050; examples include the European Green Deal [1] and the Paris Agreement (for years 2045–2060) [2]. More renewables are expected to be deployed until 2050, in Europe mainly in the form of weather-dependent solar photovoltaics (PV) and wind power, which increases the variability of electricity supply [3]. On the way to net-zero emissions, Power-to-Product (P2X) could be used for peak-shaving of nonflexible production [4], as well as to convert electricity into other storable energy carriers for diurnal or seasonal shifts [5,6]. Seasonal storage is considered essential in net-zero scenarios from a system perspective; for example, Germany may require 7 GW electrolyzer capacity for seasonal storage by 2050 [7], while the socio-economic potential of new stored hydropower is limited [8]. Hence, P2X (with power from renewables) is considered to be a central element of net-zero carbon scenarios [9].

P2X generally transforms electricity into other energy carriers (e.g., hydrogen, methane, ammonia), and in some cases back to electricity, through conversion technologies (e.g., fuel cell) [6,10]. Naturally, those properties of P2X align with the concept of an energy hub (EH), where production, conversion, storage, and consumption of different energy carriers takes place [11]. An integrated P2X energy hub (P2X-EH) can provide more operating options and potential seasonal benefits, especially in case the hub has access to liberalized energy markets, such that the hub can act as a prosumer. A prosumer can participate in the market not only as a consumer but also produces and stores energy [12]. Sufficiently large prosumers on the community level are expected to join directly the liberalized wholesale market in the future [13], enabled by the increased decentralized renewable electricity generation and the

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developments of micro-grids and virtual power plants (VPP) [14]. Additionally, the EU European Council [15,16] announced the corresponding legislation and promotion on active prosumers joining the liberalized market directly. Hence, we explore the energy trading operation for such a new type of market participants.

As outlined in the literature review in Section 2, integrating P2X into multi-energy systems (MES) is an active research area. However, few of these studies consider a P2X-EH acting as a prosumer in energy markets and investigate its trading under different operation modes and boundary conditions. On the other hand, some studies consider P2X in a market environment, but rather as a single technology or a balancing tool coordinated with renewable production than a multi-energy community with its own demand profiles. Instead of introducing an aggregator to arrange end-users and facilities in the community, we consider the entire system as an energy hub prosumer, as it can directly coordinate various multi-energy technologies and optimize energy usage. Meanwhile, it reduces the complexity of the system that uses aggregators and its requirement for advanced metering infrastructures. Moreover, the onerous contracting, high dependence on reliable information, and the possible profits' conflict between prosumers, and between prosumers and aggregators may lead to inefficiency in the hierarchical management involving aggregators [17–19]. There is a likely potential that an aggregator may fail to control a large variety of energy sources optimally. The novelty of this study is to evaluate numerically the operation modes of a P2X-EH acting as a prosumer under a wide range of options, with an emphasis on different degrees of energy market access (to both the electricity and retail selling of hydrogen) resulting in daily and seasonal operational pattern.

Local use of P2X attracts particular attention because it is highly dependent on overall electricity supply [20] and the relatively high transmission costs of hydrogen if the existing gas pipeline infrastructure is not repurposed, or hydrogen is converted to methane. P2X can reduce the usage of the power transmission grid to avoid congestion and costly grid upgrades by absorbing the generated power locally. In particular, prosumers having high renewable potential apply P2X with storage for self-sufficiency (electricity and heat demand) and low emission targets [21]. In our study, we consider the operation of a P2X-EH in a community with local renewable resources, where local electricity and heat demand must be satisfied; the community is still on an (intermediate) distribution grid level, such that wholesale market access comes with grid fees and is conditional on grid line capacity. A case study based on real-world data from a village of Switzerland, Zernez, is used for numerical analysis. With a focus on the year 2050 and the ambition to achieve carbon neutrality, we investigate the optimal investment, operation, and trading decisions of such a P2X-EH in the future electricity day-ahead and retail hydrogen market, considering different levels of market integration and players' characterizations. The operational patterns of P2X are also investigated in terms of the interplay of diurnal and seasonal storage and local demand satisfaction.

An electricity wholesale day-ahead market model is used to determine hourly price levels of representative days in the future stringent climate scenario; the prosumer is modeled as a price-taking player in the electricity market. The integrated modeling allows for a coherent parametrization: for example, in our sensitivity analysis on the carbon price, the electricity prices are adapted according to the market model, which considers the coherent decarbonization scenarios of Switzerland and the surrounding countries.

The remainder of this paper is organized as follows. We summarise the existing literature on EHs (or more general, MESs) and energy market trading of P2X in Section 2. In Section 3, the P2X-EH is specified, and the corresponding optimization problem is formulated. In Section 4, the main assumptions and data input are described. In Sections 5 and 6, the results are given, with a sensitivity analysis of key factors, e.g. grid access, availability of a hydrogen retail market, carbon and retail hydrogen prices. Comparing with other studies, the results are further discussed in Section 7. Eventually, Section 8 concludes the study.

2. Literature review

This section gives a brief overview of relevant literature on Multi-Energy-Systems (MES) and energy market modeling with P2X.

Many publications deal with system benefits of P2X in MESs. Habibifar et al. [22] use a mixed-integer linear programming (MILP) model to investigate the effects of power-to-gas (P2G) on a multi-energy hub (electricity, gas, and heat). They show that adding P2G decreases the total operating cost by reducing gas purchases. Salehi et al. [23] include a gas dispatch network in their MES and allow the methane produced from P2G to be sold to the gas network. Their results indicate that P2G, together with storages, can mitigate gas network congestion. Mansouri et al. [24] consider both investment and operation decisions of an EH to meet electric, heat, and cooling demand. Using mixed-integer nonlinear programming (MINLP), the optimization indicates that P2G can reduce both investment and operation costs of the system as well as carbon emission. While in the study of Yuan et al. [25], the reduction of carbon emission is mainly caused by carbon recycling. They propose to use P2G in a clean hydrogen-based energy system and found that the system operation cost is reduced because adding P2G enables the system to be independent from the upstream grid. Najafi et al. [26] investigate the effects of P2G on the robust operation cost of a MES in a linear max-min-max optimization model, where the system operation cost is minimized under the condition of maximization of wind generation and market price estimation deviation. In their model, uncertainties related to wind generation outputs and electricity prices are considered. Such uncertain parameters usually include PV generation / solar radiation, wind generation/speed, energy load and energy market prices [25,27–30]. Considering combined heat and power (CHP) with a carbon capture system (CCS) and P2G, Ma et al. [31] find that such a combination can increase renewable energy deployment (wind by 25%; PV by 30%). Ding et al. [32] implement a two-level multi-objective optimization model and show that P2G can increase the level of renewable energy penetration of an integrated MES to 90% and reduce the local wind curtailment rate to 0.6%. Similar results are reported from studies of Huang et al. [33], Li et al. [34], Salomone et al. [35]: On the supply side of MES, especially for a renewable-based system, P2X helps to integrate surplus renewable generation and reduce operational cost. On the local consumption side, Weiss et al. [36] investigate the operation of a P2G plant, which provides different products and services for local utilization, including hydrogen, synthetic natural gas (SNG), O_2 for local industries, heat and steam, and CO_2 captured from local processes. In the studies of Mansouri et al. [24] and Mansouri et al. [29], the hydrogen produced from electrolysers is injected into gas-fired converters, which increases their efficiency. One of the main novelties in their research is the investigation of long-term effects of P2G up to 20 years, taking into account the annual growth of load, energy prices and the degradation rate of converters. Besides these factors, Alizad et al. [37] perform a long-time (from 2020 to 2040) dynamic design for an energy hub integrated with P2G considering the future expected development of capital costs of technologies, carbon prices and emission penalty costs. Their design aims to minimizing a total cost of investment, maintenance, replacement and operation. They demonstrate that the P2G system can improve the reliability of thermal loads. Further, Zeng et al. [38] simulate the operation of P2G in an integrating power and gas system. The results show that P2G is able to reduce total energy loss and provide flexibility for grid balancing. Besides peak-shaving ability, Zhang et al. [39] show for a regional EH using decoupled multi-step optimization that P2G supplied storage has a higher potential than electric batteries. Assuming a decentralized 100% renewable system in the future, Kötter et al. [40] show a correlation between P2G capital cost, installed capacity, and levelized cost of electricity (LCOE): A significant reduction of LCOE due to P2G could be achieved. Combined with other energy components (e.g. power-to-heat (PtH)), the LCOE of the system could be reduced further.

Several studies consider large-scale deployment of MES, and use specific regions for case studies. Such analyses usually focus on the regional potentials and sizing of optimally integrated P2X technologies from an energy system viewpoint. Zoss et al. [41] consider an integrated P2G system in the Baltic states for grid balancing and renewable methane supply; a significant capacity increase of wind power and P2G is considered as a pathway to increase renewable gas usage in this region. Estermann et al. [42] evaluate the feasibility of P2G to absorb local surplus solar power and CO_2 from biomass anaerobic digestion (AD) plants in Bavaria, Germany. They suggest that sub-MW (and some multi-MW due to transformers' limits) P2G plants should be installed near AD sites. Also focusing on southern Germany, McKenna et al. [43] analyze the potential of P2G in Baden-Württemberg. The authors identify the Aalen region having significant potentials for P2G (60–155 MW_{el}) by 2040 due to its large wind resources; because of hydrogen blending constraints into gas grids and the lack of local CO_2 sources, P2G with air-captured or liquefied transported CO_2 is considered economical for this region. Sveinbjörnsson et al. [44] consider five scenarios of the future energy system of a Danish municipality with different energy conversion technologies, including P2G. The authors recommend a strong electrification scenario with P2G to be an energy- and cost-efficient sustainable way to help the municipality Sønderborg to reach zero emissions by 2029. The aforementioned studies rarely consider P2X integrated MES as a prosumer player in the market and investigate operation under different market modes. The impacts of such technologies on increased self-sufficiency, that is, energy security, are also usually analyzed only marginally.

Recently, market integration of P2X (mainly together with renewables) is investigated in (still relatively few) studies as follows. Lynch et al. [45] indicate that P2G investment increases with wind penetration and can accommodate more renewable generation by using a stochastic electricity market model, which determines the investment and operation decisions of generation and P2G technologies endogenously. Zhang et al. [46] and Gao et al. [47] consider coordinated wind farms and P2G facilities. They conjecture that such a combination can provide higher payoffs in electric energy and reserve markets. Apart from upstream electricity generation, the integration of downstream chemical processes has been investigated as well. Pääkkönen et al. [48], Pan et al. [49], and Sohrabi et al. [50] investigated methane reactors. The economic analysis performed by Pääkkönen et al. [48] indicates that a combination of an electrolyzer and a biogas plant is more beneficial if electricity prices have high fluctuations. By implementing a detailed physical model of an electrolysis and methanation process, Pan et al. [49] highlight the role of carbon prices in improving P2G economics. Sohrabi et al. [50] use a bi-level model to derive both an investor's investment and bidding strategy with a P2G-storage option in a stylized electricity network topology. They conclude that the benefit of P2G is related to high renewable penetration, direct hydrogen sales, and optimal plant placement.

Furthermore, P2X technologies, which transform electricity into different energy carriers, link naturally to other energy sectors, such that market coupling with P2X is an active research topic. Commonly investigated markets are a combination of an electricity and gas market [46,51–56]. Liu et al. [52] present an integrated MES with P2X to increase the flexibility and profit of a load-serving entity in a tri-layer multi-energy day-ahead market. Given wholesale and retail energy prices, the study uses a detailed dispatch model (taking the uncertainties into account by weighted average of expected profit and a risk measure, which in this case is the conditional value at risk). Deploying similar method on risk mitigation, Moradi et al. [55] indicate that integrating P2G into an energy hub enables the hub to make cross-product arbitrage between electricity and gas markets. In their study, a comparison between risk-based and risk-averse optimization strategies is made. Xi et al. [54] introduce P2G as a flexible resource in a game-theoretic equilibrium model, where three subsystem operators (natural gas, district heat, and electric power system) compete for profits in the gas and electricity markets. They test different configurations of flexible resources in the system and different participating levels of gas and power load. Their results for the short-term show that the increased coordination of flexible resources reduces wind curtailment and increases social welfare. Pavić et al. [56] model the operation of a PV-battery-hydrogen plant in day-ahead markets of electricity, gas and hydrogen and electricity reserve market. Reserve service and hydrogen supply are shown to provide main profits for such a plant. In their model, hydrogen tank is cycled on a daily basis. Most of the aforementioned market case studies consider daily (24-hour) operations; yearly trading patterns of P2X players are usually not considered, and as mentioned in the introduction, different trading modes are also not considered.

3. Methodology

The P2X-EH is modeled as a price-taking prosumer in an electricity market model, the Cross-Border Electricity Market (BEM) model, which is developed in the Laboratory for Energy Systems Analysis (LEA) of the Paul Scherrer Institute [57]. The model represents a Nash-Cournot game, in which all players make investing (in capacity expansion) and operating decisions simultaneously to maximise their profits under electricity generation and transmission constraints. Taking prices determined by central players in the day-ahead electricity market, the hub maximizes its profits through trades with the day-ahead electricity market, the hydrogen retail market, and a local heat utility. In this section, we first discuss the features of the prosumer player in Section 3.1 and then details of model integration in Section 3.2.

3.1. P2X-EH prosumer player

The investigated P2X-EH prosumer on community level comprises local renewable electricity generation technologies, a P2X platform, and technologies to serve local consumers (Fig. 1). The hub supplies energy for local electricity and heat demand; and also hydrogen demand in the optional case of connecting to a hydrogen retail market (cf. Section 5), where a step-curve of demand based on different sectors' prices (end-users willingness to pay (WTP)) and volumes is considered. The hub can trade electricity on the (national, nodal) wholesale market. The P2X platform comprises an electrolyzer, a hydrogen storage tank, a methanation unit, electric fuel cells (FC), and fuel cell with combined heat and power (FC CHP). The FC CHP provides both electricity and heat to local consumers. Electric heat pumps are chosen as the reference (cost-competitive) heating technology. Similarly, we assume gas combustion as a reference heat technology, modeled as an exogenous heat source (e.g., provided through district heat).

Apart from a variant with and without retail hydrogen market access, we consider a variant where the EH has a relatively high renewable local resource installed by means of an additional run-of-river (RoR) hydropower plant. This allows considering players who can act mainly as sellers in the electricity market (instead of buyers).

Because of our main objective to analyze the performance of a P2X-EH prosumer in a long-term net-zero carbon scenario, we assume in most of the subsequent analyses (if not explicitly mentioned otherwise) that capital costs of the initial P2X platform are sunk in the year 2050 while the hub has the option to install additional rooftop solar PV for local power supply and electric batteries for diurnal storage cycles; the initial P2X platform can also be expanded.

3.2. Integration of the P2X-EH prosumer in electricity market modeling

The P2X-EH is modeled as a prosumer player in the BEM model. The framework of the P2X-EH extended BEM model is presented in Fig. 2 The market regions of BEM are Switzerland and its surrounding countries, namely Austria (AT), France (FR), Germany (DE), and Italy (IT). In the model, power producers are aggregated at a country level and the buyers are represented as elastic (inverse-demand curve). The bottom-up BEM model is calibrated with EPEX market data and includes the major categories of electricity supply technologies to represent realistic market bidding [57–59]. The BEM model allows mark-ups between

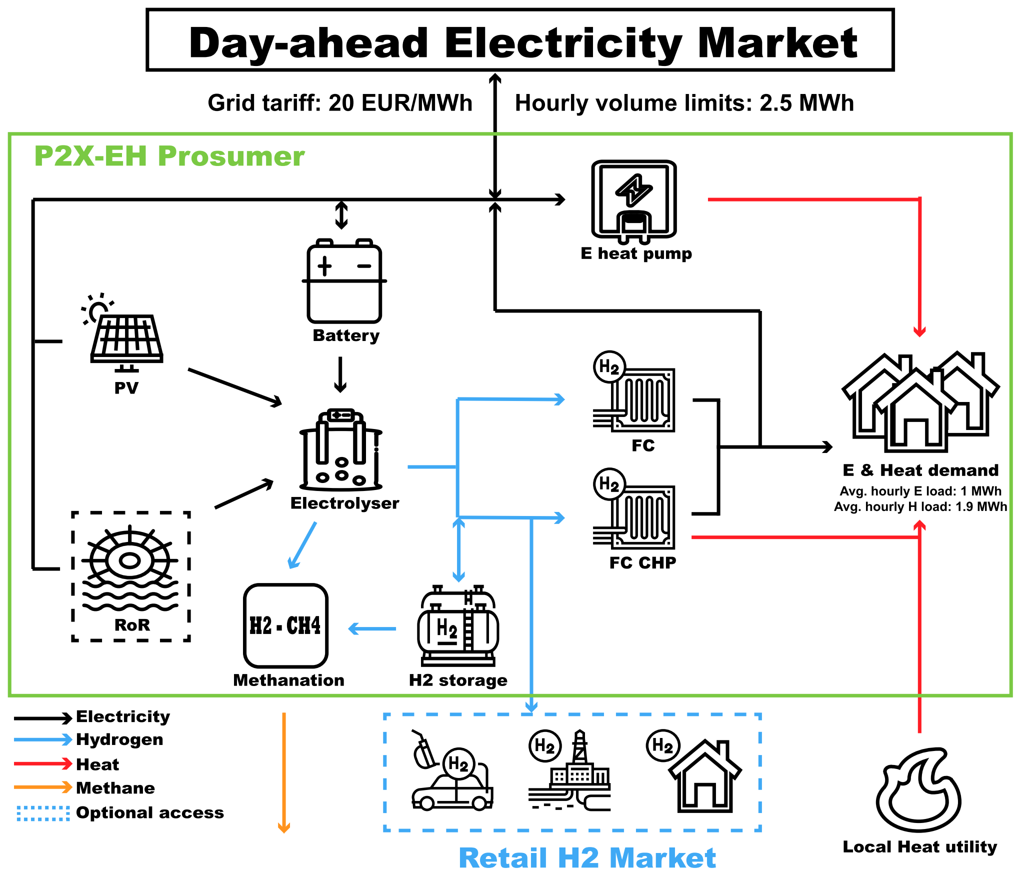


Fig. 1. P2X-EH with access to electricity market trading. Optional: access to retail hydrogen market and run-of-river (RoR) hydropower plant.

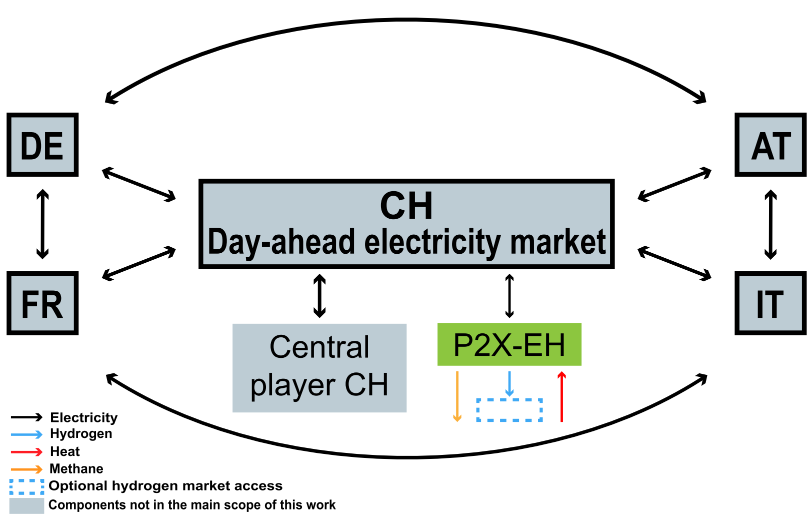


Fig. 2. The framework of P2X-EH extended BEM model.

electricity prices and marginal generation costs by extending the Nash-Cournot equilibrium by conjectural variation (CV) parameters, which enable adapting the degrees of imperfect competition to be closer to observed market data (see, e.g., also Corts [60]). We assume the EH prosumer to be relatively small, modeled as a price-taking player with marginal cost bids. The model is operated for a year, which is divided into four seasons, and each season is represented by a typical day profile of 24 h. Thus, the representative load periods of the model comprise $4 \times 24 = 96$ h. The BEM model (extended with the P2X-EH player) is implemented in GAMS [61]. Next, we describe in detail the optimization problem of the P2X-EH player.

3.2.1. Objective function

In the model, all players compete in the market in each load period to maximize yearly profits. The objective function of the annual profit of the prosumer player i is

$$\max \; R_i^E + R_i^M - C_i^I - C_i^O - C_i^D - C_i^H, \tag{1}$$

where R_i^E and R_i^M denote the revenues of selling electricity and methane, and the cost components comprise annualized capital costs of new installed capacities, C_i^I, operation & maintenance costs, C_i^O, (distribution to transmission) grid usage costs, C_i^D, and heat costs, C_i^H; heat costs are the additional expenses that the prosumer pays for external heat supply if needed.

The yearly revenue of prosumer i from electricity trading is

$$R_i^E = \sum_{n=1}^{N} \sum_{l=1}^{L} \Big(\sum_{j=1}^{J} (q_{nijl} - q^i_{nijl}) - D^E_{nil} \Big) p_{nl} \tag{2}$$

where the revenue is summed over markets n (with the number of markets N; $N = 1$ for the EH player in our numerical case study), over the load periods l (with L periods in a year, usually hourly), and supply technologies j (with number J of technologies). The quantity of electricity produced and consumed by a technology is q_{nijl} and q^i_{nijl}, the local demand for electricity is denoted by D^E_{nil}, and the electricity market price in load period l is p_{nl}, which is given by the day-ahead market. The electricity demand of the day-ahead market is elastic to the market price, and the demand-price relationship is assumed linear [62].

The yearly revenue of player i from the selling of methane is

$$R_i^M = \sum_{n=1}^{N} \sum_{j=1}^{J} \sum_{l=1}^{L} q^M_{nijl} (p^M_{nl} + p^C_{nl} r_j), \tag{3}$$

where q^M_{nijl} is the methane production, p^M_{nl} is the exogenous natural gas price (without carbon price), p^C_{nl} is the carbon price, and r_j is the carbon emission factor of natural gas. The methane is synthesized by electrolyzer-produced hydrogen and carbon dioxide. Thus, the carbon price (by the emission factor of gas) is added in (3) to the natural gas price.

The capital cost of player i (for EH and also for a centralized producer player) is

$$C_i^I = \sum_{n=1}^{N} \sum_{j=1}^{J} I_{nij} x_{nij}, \tag{4}$$

where I_{nij} is the annualized capital cost for technology j in market n, and x_{nij} is new installed capacity. Players can invest in new technology (if deemed profitable) up to the socio-economic potential of the technology [63].

Operational cost consists of marginal production cost and fixed operation and maintenance cost. The operational cost of player i is

$$C_i^O = \sum_{n=1}^{N} \sum_{j=1}^{J} \Big(\sum_{l=1}^{L} C^v_{nij} q_{nijl} + C^f_{nij} \Big), \tag{5}$$

where C^v_{nij} is the marginal production cost of technology j in market n, C^f_{nij} the fixed operation and maintenance cost.

The EH prosumer on the intermediate (community) grid-level pays a distribution grid fee for traded electricity (for both sell or purchase). The associated cost for the prosumer i is

$$C_i^D = \sum_{n=1}^{N} \sum_{l=1}^{L} (e^i_{nil} + e^e_{nil}) E^d_{ni}, \tag{6}$$

where e^i_{nil} and e^e_{nil} are the electricity import and export trading amounts from/to the wholesale market (i.e. the EH player buys or sells on the market); $e^{i/e}_{nil} \geq 0$, and export and import trades cannot be both strictly positive in the same load period l because we assume the grid fee E^d_{ni} to be strictly positive.

The hub uses heat produced by the electric heat pump and by FC CHP to meet the (local) heat demand. Alternatively, as a fallback option, heat can be procured externally at a price P^H_{nil} (if needed in some load period l). The costs for the EH prosumer i for the external heating supply is

$$C_i^H = \sum_{n=1}^{N} \sum_{l=1}^{L} \Big(D^H_{nil} - \sum_{j=1}^{J} q^H_{nijl} \Big) P^H_{nil}, \tag{7}$$

where D^H_{nil} is the heat demand in load period l of the EH, q^H_{nijl} denotes the heat production, and P^H_{nil} is the external price for the heat service.

As a variant (cf. Section 1 and Fig. 1), we also consider direct hydrogen selling on retail hydrogen markets considering different end-used sectors. We allow for different prices and demands for sectors (e.g., industry, residential, transport). The revenue from direct hydrogen selling over all sectors s is

$$R_i^{H_2} = \sum_{n=1}^{N} \sum_{s=1}^{S} \sum_{l=1}^{L} p^{H_2}_{nsl} f^{H_2}_{nisl}, \tag{8}$$

where S is the number of sectorial hydrogen retail markets, $p^{H_2}_{nsl}$ the hydrogen price, and $f^{H_2}_{nisl}$ the sold quantity. In this variant, the objective function (1) of the prosumer player i is augmented by (8):

$$\max \; R_i^E + R_i^M + R_i^{H_2} - C_i^I - C_i^O - C_i^D - C_i^H. \tag{9}$$

3.2.2. Constraints

In the following, we describe the energy balances and market constraints of the P2X-EH prosumer; the conventional technology generation constraints in the model BEM, for example, capacity constraints, which also apply to central supply players, are in Panos et al. [57] and Panos and Densing [58, Suppl. Material]. The constraints can be categorized by energy carrier: electricity, heat, and hydrogen (together with methane).

For electricity, the local (end-user) demand of electricity equals the electricity produced in the hub and the net import:

$$\sum_{j=1}^{J} (q_{nijl} - q^i_{nijl}) + e^i_{nil} - e^e_{nil} = D^E_{nil}, \tag{10}$$

where the total electricity demand of the EH prosumer i is compose of local end-user demand D^E_{nil}, consumption from electrical heat pumps and electrolyser, and battery charging (q^i_{nijl} for j = 'Elcheatpump', 'Electrolyser' and 'Battery'). The demand response of the system is enabled by flexible technologies. For example, when electricity prices are high, the player can decrease its electrolyser and heat pump operation or increase its FC CHP, which uses the stored hydrogen. Demand response can also be achieved from the supply side by discharging batteries. When electricity prices are low, the player can increase its electrolyser operation and start to charge batteries. The electricity trade between the EH prosumer i and the wholesale market must be within the distribution grid capacity limits E^c_{ni} in each load period l:

$$-E^c_{ni} \leq e^i_{nil} - e^e_{nil} \leq E^c_{ni}. \tag{11}$$

For heat, the local demand equals the supply from the production of the hub and from the alternative (external) heat supply as heat storage is not considered here:

$$\sum_{j=1}^{J} q^H_{nijl} + h^i_{nil} = D^H_{nil}, \tag{12}$$

where h^i_{nil} is the external heat supply input. The FC CHP technology produces both electricity and heat: the ratio between electricity and heat for j = 'FC CHP' is

$$\frac{q^H_{nijl}}{\eta^H_j} = \frac{q_{nijl}}{\eta^E_j}, \tag{13}$$

where η^H_j and η^E_j are the heat and electricity generation efficiency respectively.

In the variant without retail hydrogen market connecting, the hydrogen generated by the electrolyzer is in balance with the consumption of FC, FC CHP, and methanation; the storage tank is also modeled as technology (j = 'H2 tank') acting as a buffer and being connected with an existing hydrogen storage cavern with larger volume:

$$\sum_{j=1}^{J} q^{H_2}_{nijl} - \sum_{j=1}^{J} q^{iH_2}_{nijl} = 0, \tag{14}$$

where $q^{H_2}_{nijl}$ donates the hydrogen produced from electrolyzer (j = 'electrolyzer') and $q^{iH_2}_{nijl}$ donates the hydrogen input quantity to technology j.

In the variant with retail hydrogen market connecting, the new demand pathway is added to the supply-demand balance (14):

$$\sum_{j=1}^{J} q_{nijl}^{H_2} = \sum_{j=1}^{J} q_{nijl}^{iH_2} + \sum_{s=1}^{S} f_{nisl}^{H_2}, \tag{15}$$

where $f_{nisl}^{H_2}$ is the hydrogen selling volume to end-use sector s. The sectorial hydrogen demand is assumed seasonal: for each season t, the demand that can be satisfied by the hub is within seasonal lower and upper bounds, $D_{nist}^{\min H_2}$ and $D_{nist}^{\max H_2}$:

$$D_{nist}^{\min H_2} \leq \sum_{l \in t} \sum_{s=1}^{S} f_{nisl}^{H_2} \leq D_{nist}^{\max H_2}. \tag{16}$$

4. Input data and assumptions

4.1. Cross-national net-zero carbon scenario

For our analysis of the P2X-EH prosumer, we consider a net-zero carbon electricity market environment in Europe in 2050. The geographical scope is part of the Central Western European (CWE) region, namely Switzerland and its surrounding countries (i.e., Austria, France, Germany, and Italy). The hub is situated in Switzerland. For the surrounding countries, we assume the scenario 'TYNDP Distributed Energy' of the European Transmission System Operator (ENTSO-E) [64], which assumes the decentralized generation and is compliant with the 1.5° target agreed in the Paris Agreement [2], and the corresponding net-zero goals in 2050 and beyond [1]. The assumed cross-border transfer capacity expansion is according to ENTSO-E's development plan [65].

For Switzerland, we consider the SCCER-JASM Climate (CLI) net-zero carbon scenario in 2050 [66], which comprises a more detailed energy system representation than the TYNDP scenarios and has the TYNDP electricity system scenario of the surrounding countries as a consistent boundary condition. In the net-zero scenario, the international carbon price is assumed to be 293 EUR_{2019}/tCO_2 in 2050, which complies with the ranges of UK trends estimates [67]. In a sensitivity analysis (Section 6), we also use the marginal carbon price of the net-zero constraint of the JASM-CLI scenario, which is considerably higher at 1848 EUR_{2019}/tCO_2.

For further input assumptions of the (centralized) electricity system of Switzerland and its surrounding countries, see the cross-border electricity market (BEM) model in [57,58]. For this work, BEM was recalibrated based on bidding data from 2019 from EPEX SPOT [59].

4.2. P2X-EH prosumer

We assume that the P2X-EH is operated on community level, and take a village in Switzerland as a prototype. Data of yearly demand for heat and electricity, and daily heat and electricity profiles per season are from the village of Zernez [63,68]. We assume that the conceptual village is connected to the electricity grid on a mid-layer distribution level with commercial mid-voltage distribution grid fees for large consumers in Switzerland [69]. The installed capacity of local renewable resources in 2050 is in line with the scenario 'Storage' in Yazdanie et al. [63], which emphasizes decentralized renewable deployment. The scenario is used in two different variants: a variant with low renewable resources, namely, only rooftop PV deployment, and a variant with high renewable resources that considers an installed run-of-river (RoR) hydropower plant additionally. The installed capacity of RoR plant is in line with Susasca, an existed hydro plant in the Zernez area [70]. While we assume that the RoR plant (if installed in the variant) cannot be extended, we allow for additional endogenous PV deployment up to the potential for rooftops (East-South-West roofs with up to 45' inclination; Yazdanie et al. [63]).

For the capacities of the P2X platform (i.e., electrolyzer, fuel cells, methanation unit, and hydrogen storage tank) and installed electric batteries, we use real-world data from the Real-Time Energy Management Platform [71], which includes the Energy System Integration (ESI) P2X platform installed on the campus of the Paul Scherrer Institute [72].[1] For detailed data of the initially installed capacity of the P2X-EH, see the appendix. Efficiency and cost data are year 2050 estimates, which are in line with the net-zero CLI scenario in Switzerland [66]. For consistency, we use the same scenario-dependent data of electric heat pumps and batteries. The CLI scenario also provides consistent data of the broader net-zero carbon energy system; this includes national retail hydrogen demands and the marginal costs of hydrogen, which we assume as the retail hydrogen prices per demand sector and per season. The village-size retail hydrogen demand is scaled down from the national hydrogen retail demand (by the ratio of electricity demand). Current heating prices are taken from a large Swiss district heating network [75]; future heating prices are scaled with the increase in the carbon price. As we focus on a long term scenario in 2050, current high natural gas price (due to the Russia-Ukraine crisis) is not considered. In the model, natural gas price projections (40 $EUR/MWh_{LHV_{H_2}}$) for 2050 are in line with European market prices of IEA's New Policy scenario [76]. For detailed data of the trading environment of the P2X-EH, products' prices, and maximum seasonal hydrogen demand, see the appendix (A.2 and A.3).

4.3. Market integration and player configuration assumptions

As mentioned in the introduction (Section 1), the goal of our work is to compare the results of different boundary conditions for the P2X-EH.

In terms of market integration, our main setting is that a large prosumer can trade directly in the wholesale energy market at dynamic market prices. For comparison, we also consider a case, in which the P2X-EH sells or buys at the yearly averaged market price (plus the distribution grid costs). In other words, an intermediate utility, which issues fixed-price contracts, is assumed. The pricing modes for trading with the wholesale electricity market are denoted by (D) for dynamic and (F) for yearly fixed price.

Furthermore, we consider three operating modes of the P2X-EH: (0): the hub operates without P2X technology; (1): the hub uses the P2X installed but cannot participate in the retail hydrogen market; and (2): the hub uses the P2X installed and can participate in the retail hydrogen market. Without direct selling, i.e. case (1), the use of hydrogen is restricted to re-electrifying (via FC), to heating (via FC CHP), and to converting to synthetic methane via methanation (assuming injection to the gas grid).

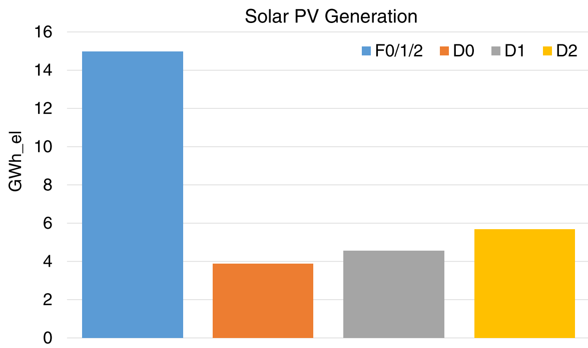
The trading (D, F) and operating modes (0, 1, 2) are considered under the base case of local renewable resource availability and also under the case with the additional RoR plant.

5. Results

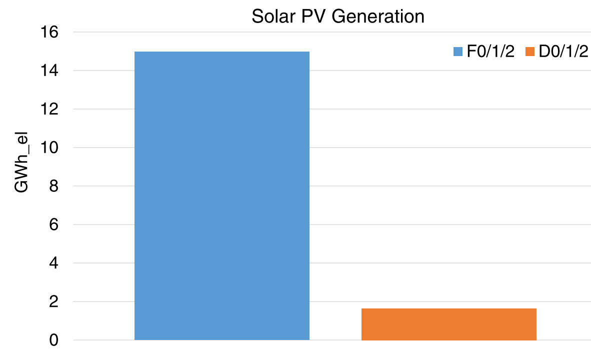
This section considers how the operation of the P2X-EH is influenced by the aforementioned different degrees of market integration. Firstly, Section 5.1 analyses the influences of different trading and operating modes on P2X technologies and renewables. Then the trading of the hub with day ahead electricity markets is considered in Section 5.2. Section 5.3 analyses the profitability of the hub in the assumed market configuration.

As detailed in Section 4.3, we investigate different trading modes under constant (F) and dynamic (D) pricing, and different operation

[1] The ESI storage tank is used for short-term storage. We assume that seasonally stored hydrogen is transported to a cavern. Typical transportation and underground storage cost are at least an order of magnitude lower than overall profitability [73,74]. Hence we do not consider such cost in the numerical examples; transport distances are also highly idiosyncratic.



(a) Base case



(b) Additional RoR

Fig. 3. Yearly generation of solar PV in (a) base case and (b) additional RoR case. Cases of market integration: (F)ixed and (D)ynamic electricity prices; (0) P2X not available; (1) P2X without retail hydrogen selling; (2) P2X with retail hydrogen selling.

Table 1
Installed capacities (including endogenous capacity expansion) of the P2X-EH under different degrees of market integration (output capacity in power units).

Technology	Unit	Initial	F0	F1/2	D0	D1	D2
Base case							
Solar PV	MW	1.8	16.0	16.0	4.1	4.9	6.1
Electrical heat pump	MW	2.8	5.6	5.6	5.6	5.6	5.6
Electrolyzer	MW	0.1 *	–	0.1	–	0.2	0.5
Additional RoR							
Solar PV	MW	1.8	16.0	16.0	1.8	1.8	1.8
RoR	MW	3.4	3.5	3.5	3.4	3.4	3.4
Electrical heat pump	MW	2.8	5.6	5.6	5.6	5.6	5.6
Electrolyzer	MW	0.1 *	–	0.1	–	0.2	0.4

* If P2X technologies are applied.

Table 2
Utilization rate of the main technologies of the P2X platform in the hub under different degrees of market integration.

	Base case			Additional RoR		
Technology	F1/2	D1	D2	F1/2	D1	D2
Electrolyzer	9%	11%	25%	9%	27%	46%
FC/FC CHP	5%	9%	9%	7%	24%	13%
Methanation	0%	0%	0%	0%	0%	0%

modes: without P2X (0), with P2X (1), and with P2X as well as additional hydrogen retail selling (2). The results of case (F1) and (F2) show no obvious difference, so we represent them together in the following sections.

5.1. *Influences of market integration and renewable potential*

The installed capacity (including the resulting endogenous capacity expansion) of the hub in the two cases (base case and additional RoR case) are presented in Table 1.

We do not observe new investment in the following technologies: FC, FC CHP, methanation, battery, and the storage tank; the original installed capacity data of those technologies is shown in the appendix (see Tables A.1). Table 2 displays the utilization rate of the P2X-related technologies of the hub.

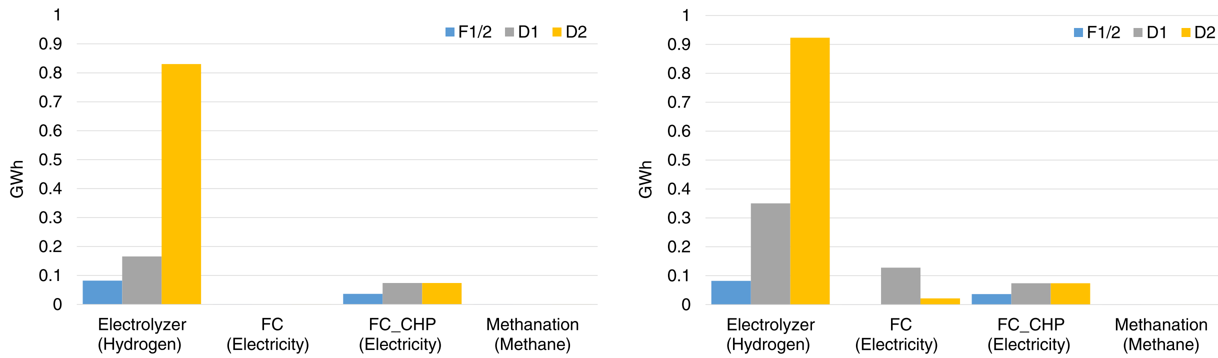
The optimal annual production of the solar PV and P2X technologies are shown in Figs. 3 and 4. In the (main) case of dynamic pricing, the utilization rate of the electrolyzer is considerably higher if direct hydrogen selling is allowed (i.e., D2), and the capacity of the electrolyzer is extended by five and four times for the base and additional RoR case, respectively. Hence, profits by selling hydrogen to the retail market promote the operation of the electrolyzer. This increase of electrolyzer operation in return stimulates renewable deployment. Correspondingly, the installed capacity of solar PV is expanded by 31% (D1) and 80% (D2), whereas (D0) exhibits no PV investment. In the base case with dynamic pricing, the PV generation increases from (D0) by 18% to (D1) and by 47% to (D2). However, in the additional RoR case with the same dynamic mode, solar PV has no significant capacity expansion; the RoR plant is operated at full load in all load periods independent of the different degrees of market access.

From Fig. 4 we also see that in general the FC CHP over the FC is chosen to use the waste heat to meet heat demand due to the energy demand profile and the higher total efficiency of FC CHP. In the case of additional RoR, the increased utilization rate of FC and FC CHP also indicates that the re-electrification (via FC) becomes profitable due to the additional local source of electricity (RoR plant without grid access costs). We also observe the increased battery usage in the case of dynamic instead of fixed pricing in both base and additional RoR cases. In the case of additional RoR, the possibility of retail hydrogen selling (D2) reduces battery usage by 8.4% compared with (D1), whereas (D0) and (D1) have almost equal levels. As hydrogen tank serves more seasonal storage, it affects more on the trading between the hub and the national market (see 5.2), rather than the daily battery storage. When the P2X-EH participates in the retail hydrogen market, the electricity shifting by battery is reduced to meet the hydrogen generation requirement. Hence, P2X per se has no significant influence on battery usage, but rather the possibility of participating in the retail hydrogen market reduces battery usage.

In the case of fixed pricing, the P2X-EH trades electricity at the average price of 108 EUR/MWh under our scenario assumptions, which results in a more profitable selling in load periods when the national markets are actually at low price level, for example, in the summer season. In this case, the hub expands the locally available solar PV up to the potential of the village (16 MW) and sells its electricity to the greatest extent to benefit from the fixed high achievable selling prices during summer. Hence, P2X is used only scarcely, and the option to join the retail hydrogen market has no impact ((F1) equals (F2) in Fig. 4). Only a tiny proportion of produced electricity (0.8% in the base case and 0.4% in the additional RoR case) is input to P2X, mainly from summer to winter for co-generation purposes.

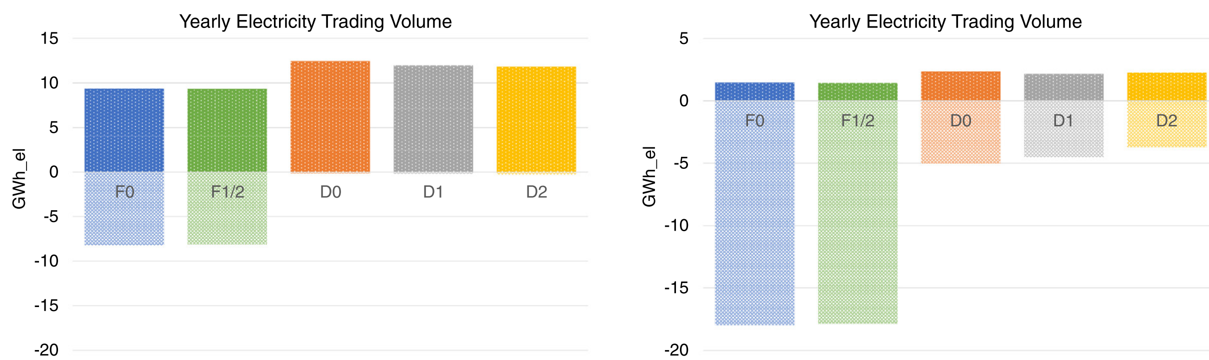
5.2. *Trading activities*

In this section, we analyze the trading between the P2X-EH and the day-ahead electricity market under two cases (base case and additional RoR case) and under the two options of electricity pricing (fixed vs. dy-



(a) Base case (b) Additional RoR

Fig. 4. Yearly generation of the P2X platform of the EH in (a) base case and (b) additional RoR case. Cases of market integration: (F)ixed and (D)ynamic electricity trade pricing; (1) P2X without retail hydrogen selling; (2) P2X with retail hydrogen selling.



(a) Base case (b) Additional RoR

Fig. 5. Yearly purchase (positive numbers) and selling (negative numbers) of electricity of the EH in (a) base case and (b) additional RoR case. Cases of market integration: (F)ixed and (D)ynamic electricity prices; (0) P2X not available; (1) P2X without retail hydrogen selling; (2) P2X with retail hydrogen selling.

namic) and P2X (not available, with and without retail hydrogen market). Compared with fixed pricing, dynamic pricing yields lower total trading activities with the electricity market, especially in the additional RoR case.

Fig. 5 shows that the use of P2X also reduces gross trading volumes, so that the hub can avoid paying distribution grid fees. Instead of selling surplus renewable generation to the market during periods of oversupply (summer) at low prices, it shifts electricity to hydrogen production. In the base case, the trading volume reduction from without P2X (case D0) is 3.7% to (D1) and 4.3% to (D2); the trades are only purchases: the hub acts as a buyer on the market. In the case of additional RoR, the reduction is higher at 9.5% to (D1) and 19% to (D2). This is because the hub has to buy electricity in winter in the base case to meet its relatively high winter demand, which can be partially supplied by P2X and seasonal storage. This scarcity is relieved in the additional RoR case, where the impacts of P2X are more obvious. It is also indicated that P2X is able to absorb more surplus energy. In this case, the hub acts in net as a seller on the market, and its yearly sellings are higher than the purchases. The main profit route of the hub is from surplus electricity to hydrogen production into the retail hydrogen market.

The reductions in trade volumes indicate that P2X can provide higher energy independence in the case of an electricity market integration with dynamic pricing, whereas in the case of fixed pricing, such hub merely tries to exploit the considerable arbitrage opportunities caused by the mis-pricing of the local renewable generation assets.

5.3. Profitability

Revenues of the P2X-EH result from selling electricity, heat, hydrogen, and methane, whereas costs refer to purchases of electricity and heat, O&M costs, and annualized capacity expansion investment. The profit is defined as revenues minus these costs. Net profit is defined as profit minus the annualized investment of the installed capacity of additional P2X facilities. Profits and net profits are shown in Table 3.

For both base case and additional RoR case, P2X increases the profit of the hub, whereas net profit is decreased because of the investment of additional P2X and solar PV. Generally, dynamic pricing generates higher profits than fixed pricing. With dynamic pricing in the base case, P2X increases profits slightly by 0.69% (D1) and by 0.87% (D2) over the case without P2X (D0). With dynamic pricing in the case of additional RoR, P2X increases profits slightly more by 0.61% (D1) and 1.1% (D2), where in (D2) the surplus of local electricity is converted to hydrogen and sold mainly to the hydrogen retail market, which is more profitable than selling the electricity on the electricity wholesale market where distribution grid fees occur.

Table 3
Profit ($MEUR_{2019}$/year) of the P2X-EH in 2050 under the different cases of market integration: (F)ixed and (D)ynamic electricity prices; (0) P2X not available; (1) P2X without retail hydrogen selling; (2) P2X with retail hydrogen selling.

	Base case		Additional RoR	
Integration	Profit	Net profit	Profit	Net profit
F0	4.15	4.15	5.90	5.90
F1/2	4.17	4.05	5.91	5.80
D0	4.35	4.35	6.25	6.25
D1	4.38	4.26	6.29	6.17
D2	4.39	4.27	6.32	6.20

6. Sensitivity analyses

In this section, the sensitivity of the results is explored for some of the primary critical market factors: (1) grid access, (2) carbon price, and (3) hydrogen price. The analysis focuses on the most promising case of (D2) having dynamic pricing and the option of retail hydrogen selling (cf. Section 5.3).

(1) Grid access

Because the P2x-EH hub is on an intermediate distribution grid level (community, village), we investigate variations in distribution grid capacity and grid fees. The results of grid capacity variations are shown in Figs. 6 and 7 in terms of yearly generation of selected technologies and installed capacity of electric batteries and hydrogen storage. The corresponding results of variations in grid fee are shown in Figs. 8 and 9. Significantly more electrolyzer is deployed in the hub under higher grid fees or under grid capacity constraints. If grid constraints are imposed, they limit the operation of the hub mainly in the winter season, when the prosumer requires to import a larger amount of electricity from the wholesale market (because own renewable production is low and demand is relatively high), which results in an increase in utilization and also in installed capacity of P2X technologies.

An exception is with lower (base case) local renewable resources, where the yearly electrolyzer generation decreases if the distribution grid capacity is severely limited (below 0.5 MW) (Fig. 6). Under the assumption of hub self-sufficiency, battery capacity increase in the base case is larger than the capacity increase of P2X because of increased short-term storage requirements, for which electric batteries are better suited due to its higher round-trip efficiencies and low operational costs. By contrast, in the additional RoR case, a lower electrolyzer deployment is not observed. Furthermore, in the base case, we observe both increases in electrolyzer deployment and in local renewable generation, whereas in the additional RoR case, there is no such simultaneous increase (Figs. 6 and 8 a).

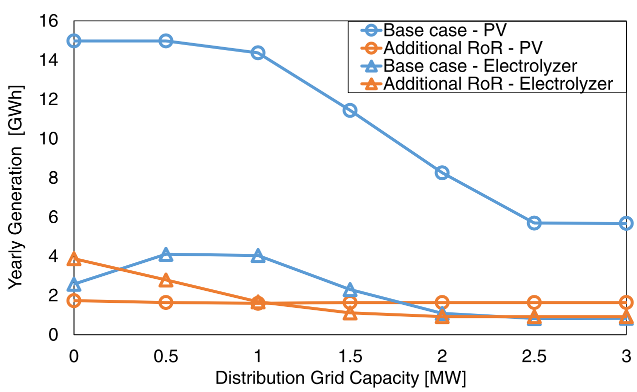


Fig. 6. Yearly generation of selected EH technologies (solar PV and electrolyzer) as a function of distribution grid capacity.

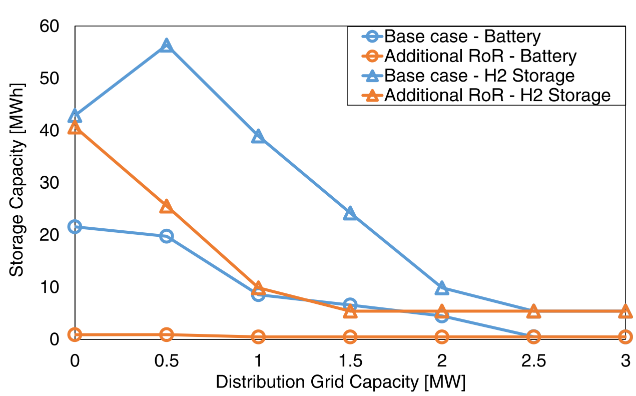


Fig. 7. Installed capacity of the storage technologies of the hub as a function of distribution grid capacity. Selected storage technologies: electric battery and hydrogen storage (in representative days).

Energy security concerns may demand for a highly self-sufficient prosumer, which can yield diminishing profits. Hence, we evaluate the profits (cf. Section 5.3) of the investigated P2X-EH prosumer by varying the grid capacity limit as shown in Fig. 10. The decrease of profits is relatively large in the base case when trading between the hub and the wholesale market is cut completely. In this case, the player must fulfill the local electricity demand by storing electricity in batteries and reducing hydrogen production (instead of making profits in the retail hydrogen market). On the other hand, the reduction of profits is relatively small in the case of additional RoR. In numbers, the hub is able to reduce its grid requirements by 2/3 at the expense of approximately 20% profit reduction in the base case (compared with no grid capacity limits), whereas in the case of additional RoR, the profit reduction is merely 1%.

(2) Carbon price

The change of carbon price is applied across the considered scenario consistently: for example, an increasing carbon price reduces the generation of carbon-intense technologies in Switzerland and surrounding countries, such that the electricity prices also usually increase; note that the hub is modeled as a price-taking player inside the wider cross-border electricity market (BEM) model (cf. Section 3).

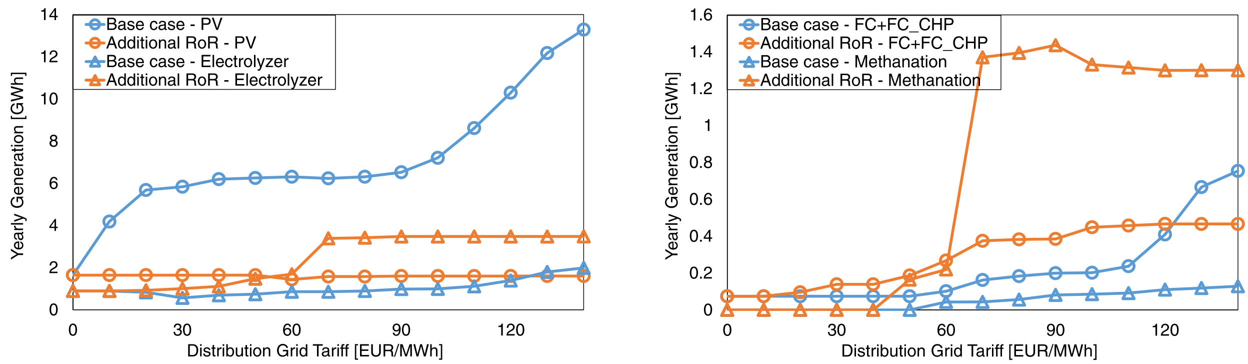
Results of the sensitivity analysis of carbon price in terms of generation are shown in Fig. 11. As mentioned, increasing the carbon price increases electricity prices. On the other hand, the increased carbon price adds more value to the methanation unit of the P2X-EH (methanation was not profitable in the investigated scenario in Section 4.1 due to the lower'green'gas value than the value of selling hydrogen to consumers in the retail market). As a result, producing methane becomes more attractive than hydrogen selling at a carbon price of 750 EUR_{2019}/tCO_2. In consequence, methanation, hydrogen generation, and renewable electricity generation increase in both base and additional RoR cases.

(3) Hydrogen price

The results in Section 5.1 indicate that the ability to sell hydrogen to retail sectors is relevant for the profitable operation of the P2X-EH. Hence, we investigate the influence of such hydrogen prices on the generation of the hub. The hydrogen prices are varied between -50% and 50% of the (initial) sectorial end-use prices. As shown in Fig. 12, the hub stops selling hydrogen to retail hydrogen markets when the hydrogen price is lowered to -40% and -20% in the base case and in the additional RoR case, respectively.

Hydrogen is preferably sold to the high WTP sector until the assumed demand limit is reached. However, suppose the hydrogen price is increased beyond 10%: In that case, the revenue of selling hydrogen to medium and low WTP sectors can also cover the production cost, and the hub starts to sell hydrogen also to those sectors (Fig. 12).

The impact of the variation of hydrogen prices on the operation of the hub is shown in Fig. 13. The increased hydrogen selling volume also increases electrolyzer generation (Fig. 13b). Similar to the results of the sensitivity of grid access (cf. Figs. 6 and 8 a), the increase in hydrogen price affects the solar PV generation only in case the hub has (initially) low renewable resources (Fig. 13a). By contrast, the hydrogen prices cannot affect FC and FC CHP operations in this base case. On the other hand, the FC and FC CHP operation in the additional RoR case is reduced if the hydrogen prices are increased by 40%, such that hydrogen can be sold more profitably to end-use sectors (Fig. 13c).



(a) Solar PV		(b) Electrolyzer

Fig. 8. Yearly generation of technologies as a function of distribution grid tariff. Technologies: (a) solar PV and electrolyzer, (b) fuel cell and fuel cell CHP and methanation.

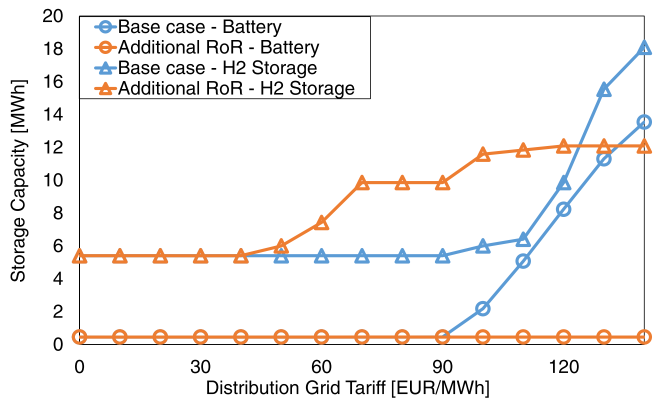


Fig. 9. Installed capacity of the storage technologies of the hub as a function of distribution grid tariff. Selected storage technologies: electric battery and hydrogen storage (in representative days).

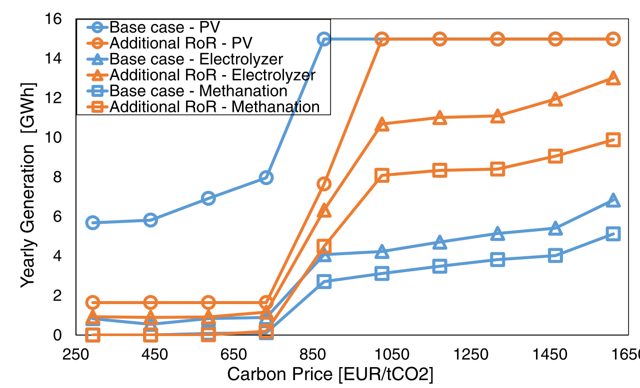


Fig. 11. Yearly generation of selected hub technologies (solar PV, electrolyzer, battery, and methanation) as a function of the carbon price.

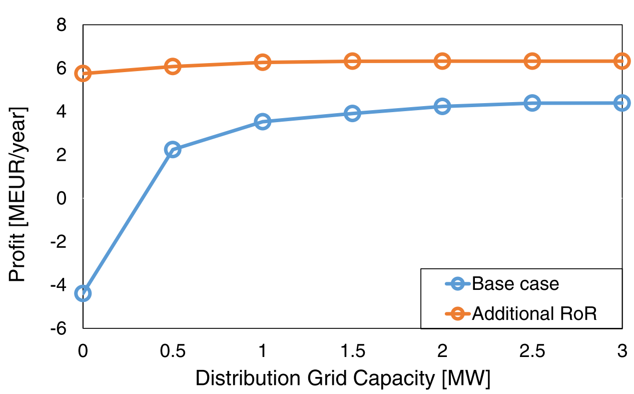


Fig. 10. Yearly operational profits of the hub as a function of distribution grid capacity.

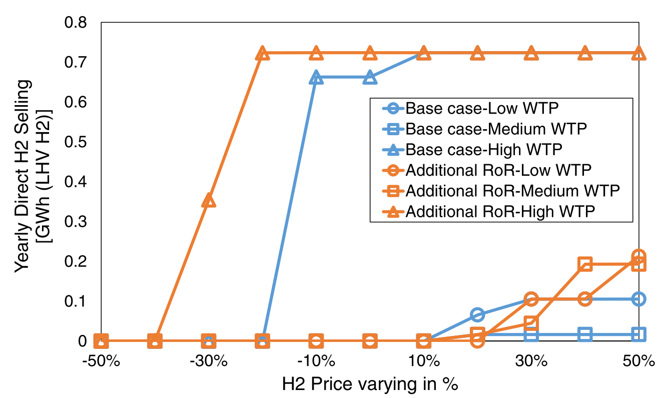
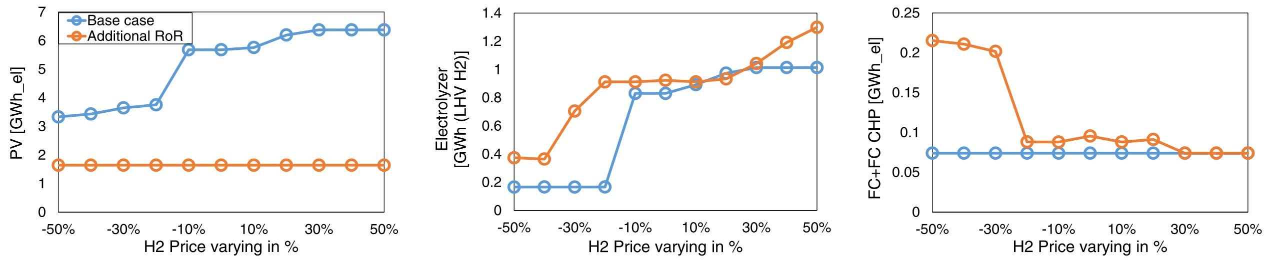


Fig. 12. Yearly hydrogen selling of the hub in the hydrogen retail market.

7. Discussion

Our results indicate that the availability of P2X has limited potential for the energy hub to make profits in the market under the assumed framework conditions. In the most promising case with dynamic trading and full market access, the assumed player increases profits by 1%. Such small profit increases are in line with Agabalaye-Rahvar et al. [77], who modeled a gas-fired plant combined with a wind power unit and P2G-storage facilities, where P2G is used mostly as auxiliary equipment. In their analysis, also gas purchase constraints and market price uncertainty are considered, but they only model for 24 h; they report 4% maximal decrease in operational costs. Breyer et al. [78] evaluated the profit of a P2G plant embedded into a pulp and paper mill with an on-site bio-diesel plant under two scenarios. Their results also indicate that it is difficult (but possible) for current P2G technologies to generate profits. In the more profitable scenario, the player has to make use of a multitude of income options, for example, selling hydrogen or gas in the highest priced markets, merchandising oxygen, providing heat and grid services, while purchasing cheap electricity during a relatively long time period and operating the P2G plant at of full-load hours.

Due to the high investment and relatively few full-load hours under many moderate scenario assumptions, wide-range P2X deployment may be difficult to achieve from a purely economic viewpoint [79]. But unprecedented globally high gas and electricity prices, as currently being witnessed, may serve to incentivize P2X applications more rapidly than



(a) Solar PV **(b)** Electrolyzer **(c)** FC and FC CHP

Fig. 13. Yearly generation of technologies of the hub as a function of H_2 price. Technologies: (a) solar PV, (b) electrolyzer, (c) fuel cell and fuel cell combined-heat-and-power.

previously expected due to energy security concerns. Given the large potential for this technology to decarbonize the demand side, specific political and financial support schemes may be likely to be required. Moreover, major P2X markets may be developing with large profit potential mainly directly in the transportation and (chemical) industry end-use sectors than in the electricity sector, in which the seasonal storage option (in our case not the major incentive) is usually proposed [78]. For this reason, retail hydrogen markets could provide opportunities to stimulate the development of low-carbon technologies, such as P2X.

To evaluate the effects of high-level grid access on the investigated energy hub, we consider both distribution grid capacity and grid fees in the sensitivity analysis (cf. Section 6). The effect of a grid fee can differ from a grid capacity limit. For example, by increasing the grid fee, a hub with high local renewable resources (additional RoR case) deploys more seasonal storage capacity than the base case, whereas by decreasing the (stricter) grid capacity limit, the base case needs more seasonal storage volume. Generally, the obtained results indicate that P2X can play an important role for energy security. Zhou et al. [80] and Thellufsen et al. [81] conclude similarly that P2X helps to reduce the interaction between multi-energy systems and the upper grid levels (especially by electricity export reduction). Zhou et al. [80] found that multi-energy systems with P2G reduce electricity export in the early mornings, and import in the evenings; the overall interaction is reduced by 10% compared with the original system. On a larger scale, Thellufsen et al. [81] propose a self-sufficient smart city energy design with 100% renewables. One of their objectives is to reduce grid electricity exchanges to 10%, and they realize it through a combination of P2X, heat pump, and smart charging. The result that higher grid fees increase investment in solar PV is also observed in Günther et al. [82], who consider a prosumer with solar PV and batteries (without P2X).

However, our obtained results must be considered with their limitations as follows. Our study focuses on the trading and operation of an energy hub with P2X technologies. Hence, an electricity market model is used to determine hourly future price levels for the hub. In the model, the hub joins the market as a price-taker. One limitation is that the influence of a potential large-scale deployment of many hubs on the wholesale market is not addressed. Considering the balancing and storage ability of P2X and the extra coupling between electricity, gas, and CO_2, complex inter-sectorial influences can be expected under large-scale deployment, which will be addressed in a subsequent study. In this case at higher levels of aggregation, the P2X technology may be more economic due to smoothing and economies of scale. In this regard, because we do not apply multi-sectorial (full) energy system modeling, some potential system benefits cannot be fully explored, for example by CO_2 capture in some natural gas technologies and utilization in methanation. Other energy markets, for example, the electricity balancing markets, where P2X could probably benefit are also not considered. Nevertheless, the opportunity costs of the balancing market of flexible generation cannot deviate substantially from energy-only electricity markets [83].

Another limitation is that we consider a relatively large energy hub on community level, which is in our case a village, but could also be a large hospital etc. We assume such a large prosumer can join the day-ahead electricity market directly (upper-level distribution grid fees still apply), as its yearly trading volume is over 100 MWh. On the other hand, a common prosumer on household level may need an aggregator entity to connect to the market, where our comparison case using the yearly averaged price can serve only as a crude proxy for the operating conditions of such a household prosumer.

In addition, it is worthwhile to investigate the strategic behavior of such energy hubs under different circumstances. Tushar et al. [84] and Tsybina et al. [85] give an overview of strategic bidding of distributed prosumers in peer-to-peer markets; yet prosumers with P2X are not yet covered. Further, our case study of a village assumes a varying demand profile over the time slices, the end-use demand for electricity and heat is assumed inflexible; hence, demand side management in the end-use demand is not considered.

8. Conclusions

In this study, we use integrative modeling of an energy hub inside an electricity market model to investigate a new type of prosumer, P2X energy hub, serving community demand under a net zero-carbon scenario in the year 2050, who is likely to be an emerging player on the distribution-side of future low-carbon energy systems. In the hub, we consider different energy types (electricity & heat, hydrogen, methane), and assume the relatively large prosumer can join electricity and retail hydrogen markets, respectively. The model allows for diurnal and seasonal energy storage, such that major market opportunities can be explored. The modeling emphasis is on the coherency over the entire set of input assumptions which also involves (previously obtained) consistent results of energy system scenarios; indeed, varying the whole, extensive set of parameters by a (global) sensitivity analysis is hardly feasible, such that consistency is crucial.

We considered the P2X energy hub as a market participant under different degrees of market integration and renewable resource availability: The main conclusion is that the P2X energy hub can be profitable if full access to the hourly wholesale electricity market is given and also hydrogen can be sold directly on a retail market. In other words, the prosumer profits from electricity market price variation and sector coupling. Having access to a large and accessible seasonal storage facility allows a community to make use of this. In the base case (initial relatively low local renewable resources), P2X can promote profitable additional renewable deployment (mainly capacity expansion of solar PV in our case). In terms of self-sufficiency and energy security, the electricity exchange with the wholesale market is significantly reduced if the hub can use P2X. It is shown that the utilization of P2X is driven by both supply and demand sides. From the supply side, we notice that both the generation capacity and the profile of renewables affect the installed capacity of the electrolyser and seasonal storage. More renewables and various types of generation (e.g., PV and RoR) cause electrolysers to produce more with less installed capacity, whereas more seasonal hydrogen capacity is required in the additional RoR case. With respect to the demand side, all considered operational patterns indicate that hydrogen storage is primarily used for seasonal shifts for FC CHP co-generation in winter when solar PV generation is lower and heating demands are higher. As reported in Panos et al. [66] and BFE [86], 6.8 TWh hydrogen is needed for end-use consumption for Switzerland in the net-zero scenario in 2050 and 4.5 Twh domestic seasonal storage is planned, which provides large opportunities for approximately 9000 P2X energy hubs of our size in terms of demand and approximately 10,000 in terms of storage capacity.

Sensitivity analyses were performed on the grid-access capacity and grid tariff, carbon price, and hydrogen price of the retail sectors. The benefit of a P2X energy hub prosumer is highly increased under a strict (higher level) distribution grid constraint or a high carbon price; methanation is only competitive under relatively high carbon prices. Hence, under our assumptions, selling hydrogen to the hydrogen retail market has a higher value than 'green' gas. In all cases, the increased availability of local renewable resources greatly facilitates P2X deployment.

Based on the mentioned limitations in the previous discussion section, we may consider the following extensions. Our analysis is geared to a strong-climate scenario in 2050; by contrast, in the case of a (singular) extreme weather event, stored hydrogen could be highly beneficial on system level, for example, to prevent blackouts by short-term balancing ability. To consider the diversity of days within a season, more typical days and advanced time series aggregation methods, such as clustering, should be adopted. In our setting, if severe grid-access restrictions are absent, a profitable P2X energy hub prosumer requires access to a sufficiently large retail hydrogen market, and local renewable resources should be relatively high (for example exploiting only rooftop PV may not be sufficient as in our considered cases). Hence the non-marginal system-level and scale impacts of many decentralized P2X players should be analyzed in future work.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A

Table A.1
Installed capacity data of the P2X-EH (output capacity in power).

Technology	Unit	Installed capacity
Solar PV	MW	1.8
RoR	MW	0 (base case) / 3.4 (Additional RoR case)
Electrical heat pump	MW	2.8
Electrolyzer	MW	0.1
FC/FC CHP	MW	0.1
Methanation	MW	0.1
Battery	MWh	0.4
H2 tank	MWh	5.4

Table A.2
Exogenous price input data (base scenario).

Product	Unit	Price
Methane (green gas)*	EUR/MWh$_{LHV_H_2}$	99
Heat*	EUR/MWh	241
Direct hydrogen selling (low WTP)	EUR/MWh$_{LHV_H_2}$	92
Direct hydrogen selling (medium WTP)	EUR/MWh$_{LHV_H_2}$	97
Direct hydrogen selling (high WTP)	EUR/MWh$_{LHV_H_2}$	150

* Carbon prices in year 2050 are added.

Table A.3
Maximum seasonal demand data (MWh$_{LHV_H_2}$).

Hydrogen selling sector	WI	SP	SU	FA
Low WTP	963	614	1155	988
Medium WTP	904	543	180	490
High WTP	1983	1978	1984	1986

Appendix B. Selected results: In-depth results under high market integration (D2)

The presented results show that such an energy hub is most profitable and has the highest self-sufficiency in the case of high market integration, that is, in the case of dynamic pricing and hydrogen retail selling (D2). Hence, we focus on (D2) to investigate in more detail the optimal operation of the P2X-EH.

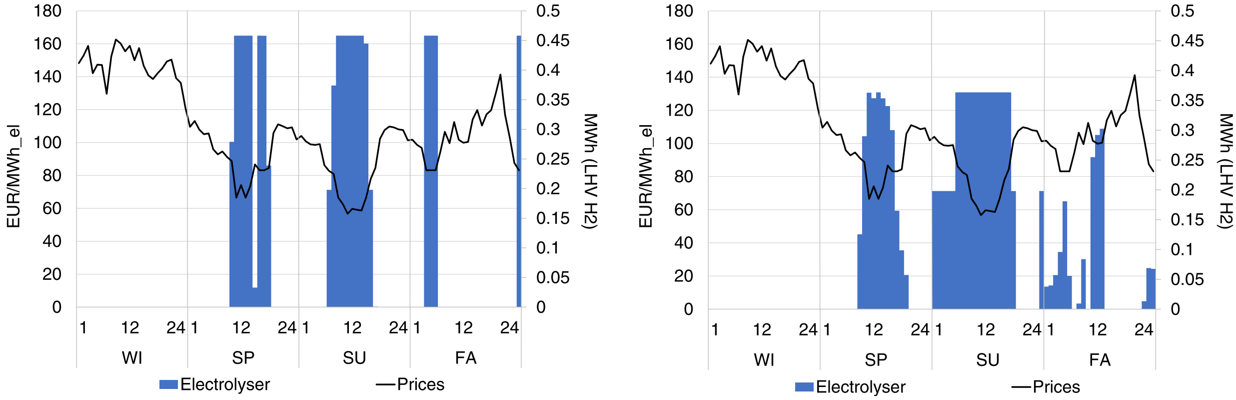
The operation of the electrolyzer in the different load periods is shown in Fig. B.1. The electrolyzer is operated mainly in the spring and summer seasons between 9am and 5pm, when solar PV generation is high and electricity prices are low. In the case of (D2), the hub invests in electrolyzers (and into new PV solar capacity in the base case) to increase profits in the retail hydrogen market (see Fig. B.2).

The hub in the base case invests in 0.36 MW$_{LHV_H_2}$ new electrolyzer, whereas the hub in the additional RoR case invests in 0.26 MW$_{LHV_H_2}$. Fig. B.1 also shows that relatively high renewables availability allows operating the electrolyzer profitably within a more extensive range of electricity prices due to the higher local resources, exempt from grid price charges. Consequently, the more comprehensive range requires less new investment in electrolyzers than in the base case. The demand response of the P2X-EH with changes in electricity prices is presented in Fig. B.3. The main demand of the hub includes a (fixed) end user demand, and the demand of electrical heat pumps, which is mainly determined by end-user heat demand. Besides, the player manages to adjust its electricity demand through electrolysers and batteries. When market prices are low, the hub operates electrolysers and stores electricity in batteries. When market prices are high, the hub operates FCs and FC CHPs, and discharges batteries.

Fig. B.2 and Fig. B.4 show the usage of hydrogen. Re-electrification (via FC) and co-generation (via FC CHP) are mainly in the winter season to reduce imports when wholesale electricity prices are high. Indeed, pure re-electrification (via FC) happens only in the additional RoR case, where larger amounts of hydrogen are available via electrolysis from the additional run-of-river electricity (Fig. B.4b).

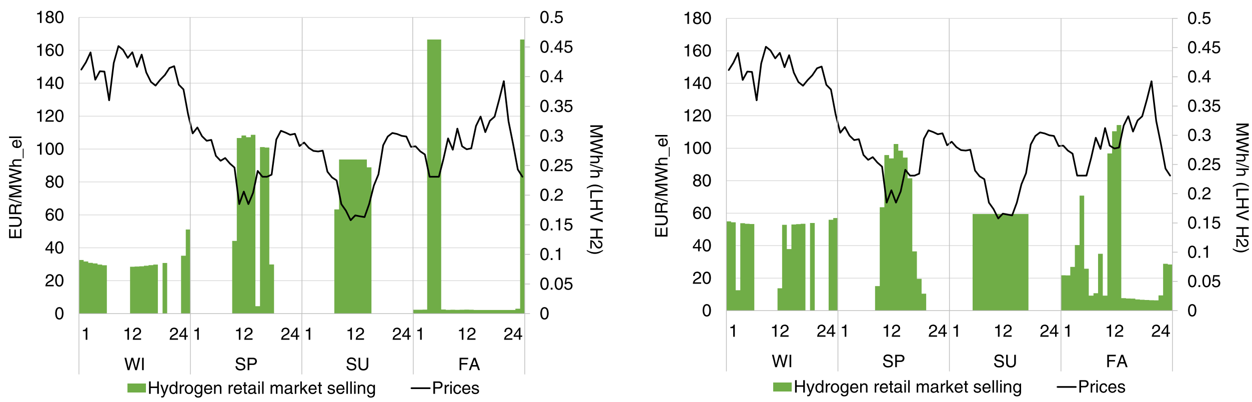
Based on the coherent use of energy system modeling results of the net-zero scenario CLI as input (cf. Section 3), consumers in some sectors are willing to pay more for hydrogen than in others (step-wise demand curve). In our results, the P2X-EH sells hydrogen only to the high-priced sector. Hence, to supply also fully demand to other sectors requires additional external sources.

Fig. B.5 shows the hydrogen storage used by the P2X-EH. Hydrogen storage is operated in diurnal and seasonal cycles. Still, the majority of operation is seasonal: Hydrogen is stored in spring and summer (during daytime), and discharged in winter to convert hydrogen into electricity and heat when local renewable generation is relatively low, and heating demand and electricity prices are relatively high. The hub in the addi-



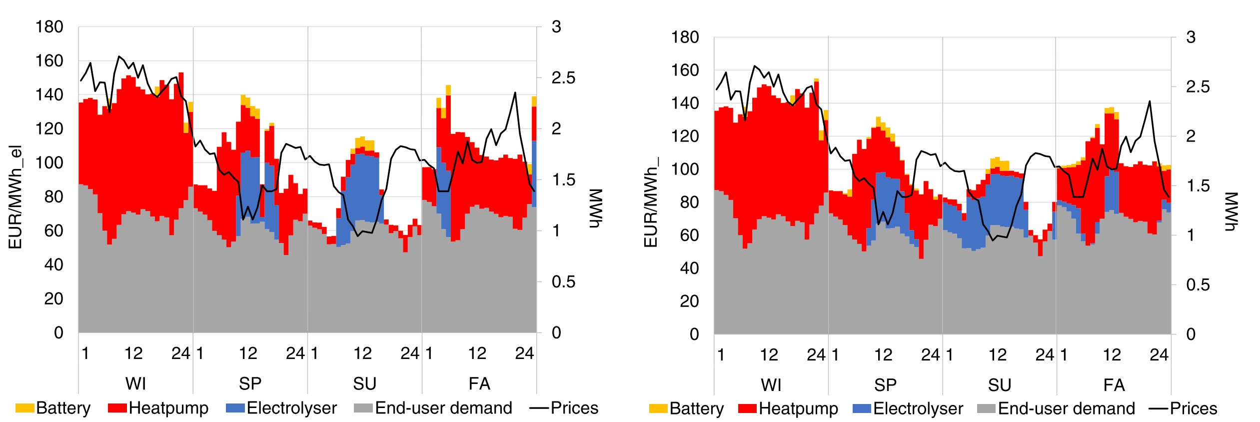
(a) Base case **(b)** Additional RoR

Fig. B.1. Electrolyzer generation of the P2X-EH with full market access (dynamic pricing & retail hydrogen selling). (a) base case, (b) additional RoR case.



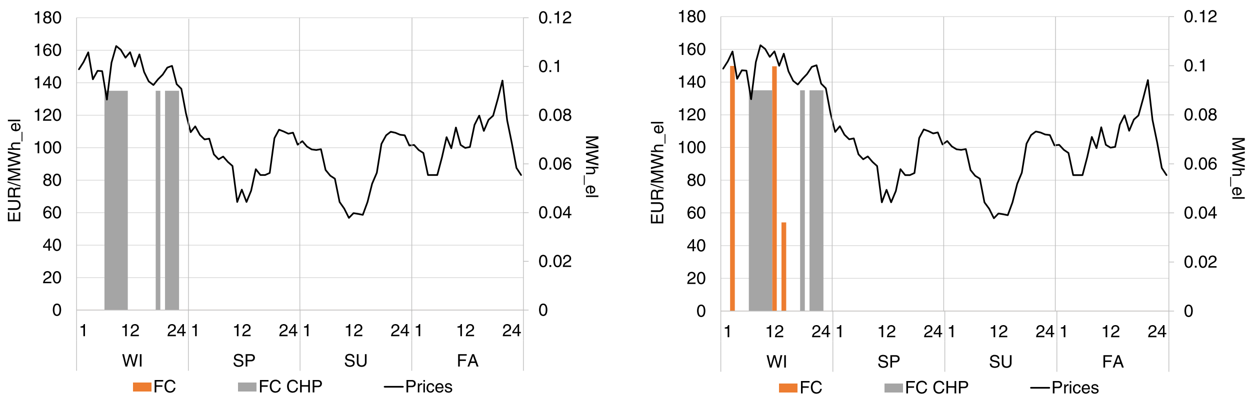
(a) Base case **(b)** Additional RoR

Fig. B.2. Hydrogen direct selling with full market access (dynamic pricing & retail hydrogen market). (a) base case, (b) additional RoR case.



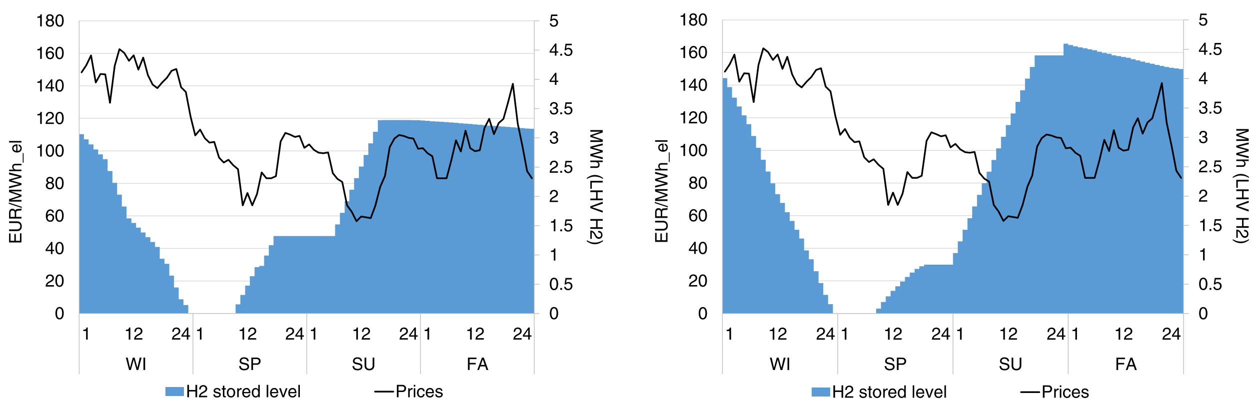
(a) Base case **(b)** Additional RoR

Fig. B.3. Total electricity demand of the P2X-EH with full market access (dynamic pricing & retail hydrogen selling). (a) base case, (b) additional RoR case.



(a) Base case (b) Additional RoR

Fig. B.4. FC and FC CHP generation with full market access (dynamic pricing & retail hydrogen selling). (a) base case, (b) additional RoR case.



(a) Base case (b) Additional RoR

Fig. B.5. Hydrogen storage with full market access (dynamic pricing & retail hydrogen selling) in representative days. (a) base case, (b) additional RoR case.

tional RoR case uses the available tank volume fully (4.6 MWh_{H_2}) once per each day during seasons with load, whereas the base case uses less (3.3 MWh_{H_2}).

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