International Journal of Hydrogen Energy 89 (2024) 883–897

Contents lists available at ScienceDirect

International Journal of Hydrogen Energy

journal homepage: www.elsevier.com/locate/he

Whole system impacts of decarbonising transport with hydrogen: A Swedish case study

Jagruti Thakur [a,*], José Maria Rodrigues [a], Sivapriya Mothilal Bhagavathy [b]

[a] Department of Energy Technology, KTH Royal Institute of Technology, Stockholm, Sweden
[b] PNDC, University of Strathclyde, Glasgow, UK

ARTICLE INFO

Handling Editor: Prof. J. W. Sheffield

Keywords:
Hydrogen supply chain
Sweden
Electricity market
Optimization
Transport
Decentralised

ABSTRACT

This study aims to carry out a techno-economic analysis of different hydrogen supply chain designs coupled with the Swedish electricity system to study the inter-dependencies between them. Both the hydrogen supply chain designs and the electricity system were parameterized with data for 2030. The supply chain designs comprehend centralised production, decentralised production, a combination of both, and with/without seasonal variation in hydrogen demand. The supply chain design is modelled to minimize the overall cost while meeting the hydrogen demands. The outputs of the supply chain model include the hydrogen refuelling stations' locations, the electrolyser's locations and their respective sizes as well as the operational schedule. The electricity system model shows that the average electricity prices in Sweden for zones SE1, SE2, SE3 and SE4 will be 4.28, 1.88, 8.21, and 8.19 €/MWh respectively. The electricity is mainly generated from wind and hydropower (around 42% each), followed by nuclear (14%), solar (2%) and then bio-energy (0.3%). In addition, the hydrogen supply chain design that leads to a lower overall cost is the decentralised design, with a cost of 1.48 and 1.68 €/kgH_2 in scenarios without and with seasonal variation respectively. The seasonal variation in hydrogen demand increases the cost of hydrogen, regardless of the supply chain design.

1. Introduction

As set by the EU in the European Green Deal, every state member must be neutral greenhouse gas emissions by 2050 and reduce net greenhouse gas emissions by at least 55% by 2030 [1]. Due to its ongoing reliance on fossil fuels, in 2019, the transportation sector accounted for 25.8% of total greenhouse gas emissions in the EU [2]. In the same year, road transport emitted 72% of all domestic and international transport GHG, thus constituting the highest proportion of overall transport emissions [3]. Therefore, it is a pivotal sector to decarbonise to achieve the targets mentioned above. Fuel cell electric vehicles (FCEVs) and battery electric vehicles (BEVs) are regarded as the two key technologies to achieve a carbon-neutral transport sector [4]. Most industry experts predict that the FCEV market will expand in heavier vehicles with high daily use, such as heavy-duty trucks, BEV market will develop in lighter vehicles with low daily use. Though there exists a competitive dynamic between the two technologies, both of them are sustainable alternatives for internal combustion engine vehicles. However, how these two technologies will penetrate the market is hard to predict as the attractiveness of each technology, from the customer's perspective, is dependent on the cost, autonomy and charging time. In the current landscape, BEVs seem to dominate and it is driven by advancements in battery technology and developments of infrastructure. However, FCEVs show a huge potential for specific heavy-duty transport, thereby concentrating on a niche sector. The current market landscape indicates a preference for BEVs for urban and regional markets, whereas FCEVs are more attractive for long-distance haulage. As these technologies are still in their infancy, developments on all these features are being announced often, which may cause uncertainty about which technology might be more suitable for the customers' needs.

What car manufacturers, policymakers and customers do know, is that an appropriate infrastructure must be in place for either of these technologies to be successful. However, developing such a network is not as straightforward as it may seem, as it originates from a cause-and-effect problem. On the one hand, there should be an assurance that a sufficient number of FCEVs will utilize these stations to justify investment in hydrogen fuelling stations and related infrastructure. On the other hand, customers want assurance that there is an infrastructure to refill their vehicles affordably before they invest in FCEVs. Both public

* Corresponding author.
E-mail address: jrthakur@kth.se (J. Thakur).

https://doi.org/10.1016/j.ijhydene.2024.09.386
Received 20 June 2024; Received in revised form 24 September 2024; Accepted 26 September 2024
Available online 1 October 2024
0360-3199/

and private organisations are aware of this problem and are looking into potential solutions where the infrastructure is built to support the growth of the FCEV business. Therefore, this study proposes to come up with a hydrogen supply chain design, that depicts the hydrogen demand and that showcases a potential infrastructure to satisfy that demand.

As hydrogen gained significant attention as a potential decarbonization solution, especially for the transportation sector, extensive research and investments have been made in its technology and infrastructure. A UK consultancy firm ranked Germany as the leading nation in financing a hydrogen economy [5]. To utilize hydrogen as a transportation fuel, it is crucial to carefully examine the entire supply chain, from production to consumption. Vehicle storage tanks must be able to store hydrogen without any leaks and withstand high pressures. Presently, many automakers use compressed hydrogen tanks for their vehicles, reaching pressures of 350 or 700 bars, depending on the vehicle type – light duty or heavy duty, respectively [6]. The most cost-effective supply system between manufacturing and transportation has been the subject of various studies. The prevailing supply chain involves pure hydrogen supplied as compressed gas or cryogenic liquid [7,8].

A study by Yang and Ogden [9] investigates a methodology to evaluate different transport options for tube or liquid trailer trucks versus pipeline delivery. The research highlights that each technology has specific cost-effectiveness in the market, and there is no universally ideal approach for the entire system. Dogliani et al. developed an Excel tool to estimate the price of hydrogen supply, considering various input factors like FCEV market share, refuelling station capacity, transportation mode, or production output for different delivery scenarios [10]. Similarly, they focused on pipeline, tube, and liquid trailers as primary distribution methods. The model includes a calculation of the hydrogen production cost; hydrogen compression, hydrogen storage as well as transportation, focussing on all the stages of hydrogen supply chain. Reuβ et al. [11] argue that given the significance of hydrogen mobility in a future renewable energy system, using electrolysis systems powered by renewable sources, this impact should not be overlooked. Furthermore, studies [10,12] have indicated that seasonal storage can play a significant role. Yet, these studies only consider scenarios involving underground solutions, like salt caverns or abandoned oil fields. In 2017, European Project COPERNIC estimated that high-pressure tank prices are about \$650/kgH_2 [13]). In addition to compressed gas and liquid storage, there are two other main methods for storing hydrogen, viz. Chemical absorption, which uses materials like metal hydrides, chemical hydrides, or liquid organic hydrogen carriers (LOHC), and physisorption, which uses materials like carbon nanotubes or metal-organic frameworks (MOF) [14].

Dagdougui [15] mentions that most hydrogen supply chain models rely on mathematical optimization techniques to reduce costs for specific scenarios. However, Reuβ et al. believe there is a lack of modelling approaches that incorporate upcoming technologies like LOHC or supply chains with seasonal storage. Therefore, Reuβ et al. [16] explore various hydrogen supply chain designs using a point-to-point analysis based on Yang and Ogden's approach, relying on existing data and expanding the investigation to include new technologies. Consequently, they consider the entire supply chain, from hydrogen production via electrolysis to large-scale storage, to bridge the temporal mismatch between demand and supply. This includes considering the transportation means and fuelling station facilities required to fill a 700-bar compressed gas tank. Moreover, the potential impacts of LOHCs as an alternate carrier system on hydrogen mobility are also considered.

A summary of modelling tools for evaluating hydrogen infrastructure given by Bolat and Thiel [17,18] makes a distinction between mathematical and analytical methods. A detailed analysis of the suggested methodologies' applicability reveals two different application scenarios viz. co-located production and liquefaction storage plants and non-co-located plants. The design of spatially resolved infrastructure for national supply strategies has been the subject of numerous studies. Seydel [19] used a GIS-based optimization mode to create a cost-effective hydrogen supply chain, which includes hydrogen generation, transportation, and refilling for a future FCEV-dominated auto market. The paper focuses on the design of truck and pipeline transportation for the distribution of hydrogen. Further, in terms of territorial characteristics, pipeline routing took the least expensive routes, while truck routing adhered to the German street network.

Reuβ et al. [16] conclude that though a single cost-effective system is preferred at the national supply system level, there is a lack of knowledge about alternation options, competing technologies and the interactions between the technologies. The focus of the literature has primarily been on the parameters of hydrogen production technologies. Technology-centric studies assess the competitiveness of various options for diverse applications and supply chain segments, using criteria like CO_2 emissions and energy demand. A critical gap exists in hydrogen production research: the disconnect between technology-focused studies and national-level evaluations. Reuβ et al. reduce this gap by analysing all aspects of the supply chain, considering Germany in 2050 as a case study and considering the geographical resolution of price, primary energy use and CO_2 emissions. Scheidt et al. [20] explore the impact of hydrogen production on the electricity sector, thus coupling the hydrogen supply chain and the electricity system, using Germany as a case study. Scheidt et al. conclude that spatially resolved electricity tariffs can result in electrolysers sited further away from consumption centres which can result in higher transport costs for hydrogen. Scheidt et al. however, focus on centralised production, without time-flexible operation and storage, and assume that electrolysers can only be sited at transmission grid nodes.

To the best of the authors' knowledge, there is limited literature on the quantitative investigation of a hydrogen supply chain for the transportation sector in Sweden. Consequently, this study develops an optimization model that represents the hydrogen supply chain for the transportation sector, considering heavy-duty trucks and passenger vehicles, for Sweden in 2030. This study is based on other works such as [16,20,21] with adaptations to incorporate time-flexible operation and a much higher time resolution. In this paper, the work by Reuβ et al. [16] is further enhanced by including a greater level of detail in each phase of the supply chain to assess the competitiveness of different technologies. This paper also explores the impact of hydrogen production on the electricity sector leveraging the model developed by Scheidt et al. [20]. Moreover, it proposes a design based on decentralised and a combination of both centralised and decentralised production, apart from the centralised one as in the mentioned papers. The output of the model is a proposed system design: where should hydrogen fuel stations be located; where should electrolysers be located and with what sizes; at what time should the electrolysers be operational; and which electrolysers supply which hydrogen fuel stations. Furthermore, it shall answer the following research questions.

- What is the potential demand for hydrogen from heavy-duty trucks and passenger vehicles in Sweden in 2030?
- What are the costs of hydrogen for the transportation sector whilst considering the spatial distribution of Hydrogen Refuelling Stations (HRS) and hydrogen demand in 2030?
- What are the financial impacts of having this hydrogen demand on the electricity market?

The remainder of the paper is organized as follows: Section 2 entails methods followed by data in section 3. Section 4 discusses the results followed by the conclusion in section 5.

2. Methods

To address the research questions mentioned above, the hydrogen supply chain as well as the electricity system were modelled and then parametrized with data of Sweden's transportation sector, namely heavy-duty trucks and passenger vehicles, and Sweden's electricity sector in 2030. As seen in Fig. 1, the electricity system was modelled, parametrized and run prior to the hydrogen supply chain models since the hourly electricity prices, in each bidding zone, are used as inputs for the hydrogen production costs. The centralised hydrogen supply chain was designed considering the centralised production of hydrogen, which is produced via electrolysis, and then transported to hydrogen refuelling stations in both gaseous and liquid states. It is assumed that the hydrogen is transported via delivery trucks. In contrast, the decentralised supply chain design considers on-site production of hydrogen, which means that each HRS site includes an electrolyser, thus cutting off costs for hydrogen distribution. For the scenario with seasonal variation, the hydrogen consumption per km was set to have different values according to the ambient temperature. The average hydrogen consumption across all days in the year was set to be the same in the scenario with no seasonal variation, yielding the same annual hydrogen demand.

The hydrogen supply chain design is based on the work developed by Scheidt et al. with adaptations to turn the model into annual optimization with an hourly resolution instead of daily optimization [20]. Therefore, the model is more detailed and allows for time-flexible operation, making use of hours with lower prices as well as allowing for variations of the hydrogen demand throughout the year, bringing the model closer to reality. The work developed by Scheidt et al. was also adapted to design the decentralised as well as the mixed model [20]. The model was run in Python using Gurobi solver and it took more than 24 h to solve one model while using a computer with 256 GB RAM.

2.1. Centralised hydrogen supply chain model

The mixed integer linear programming model for the hydrogen supply chain comprehends production, conversion, transportation, and refuelling station costs.

The sets and indices used in the mode are defined in Table 1. The objective function of the model is described below

Table 1
Sets, indices and variables.

Sets and Indices	
$p \in P = \{1, 2, \ldots, 222\}$	Index and set of potential electrolysis power plants
$f \in F = \{1, 2, \ldots 99\}$	Index and set of hydrogen fuel stations
$t \in T = \{1, 2, \ldots, 8760\}$	Index and set of hours in a year
$d \in D = \{1, 2, \ldots, 365\}$	Index and set of days in a year.
Decision Variables	
$x_{p,t} \in \{0, 1\}$	This variable is equal to one if there is an electrolyser installed at location p and working at time t, and 0 otherwise
$hp_{p,t} \geq 0$	This variable determines the hydrogen production at electrolyser p and time t, in kg.
$y_{p,f} \in \{0, 1\}$	This variable is equal to 1 if transportation between electrolyser p and hydrogen fuel station f has been established, and 0 otherwise
$ht_{d,p,f} \geq 0$	This variable determines how much hydrogen was transported at a given day d from electrolyser p to fuel station f, in kg
$x_{f,t} \in \{0, 1\}$	This variable is equal to one if there is on-site production at fuel station f and working at time t, and 0 otherwise
$hfs_{f,t} \geq 0$	This variable determines the hydrogen production at fuel station f and time t, in kg
$select_f \in \{0, 1\}$	This variable is equal to one if that hydrogen fuel station f is to be supplied by on-site production, and zero otherwise

$$\sum_{p \in P} PCC_p + + CCC_s + SCC_s + TCC_s + \sum_{p \in P} POC_p + \sum_{p \in P} COC_{p,s} + SOC_s + \sum_{p \in P} \sum_{f \in F} TOC_{p,f} \tag{1}$$

where.

PCC_p: Determines the production capital costs of electrolyser p, in €.
CCC_S: Determines the conversion capital costs at state s, in €.
SCC_s: Determines the fuel stations' capital costs at state s, in €.

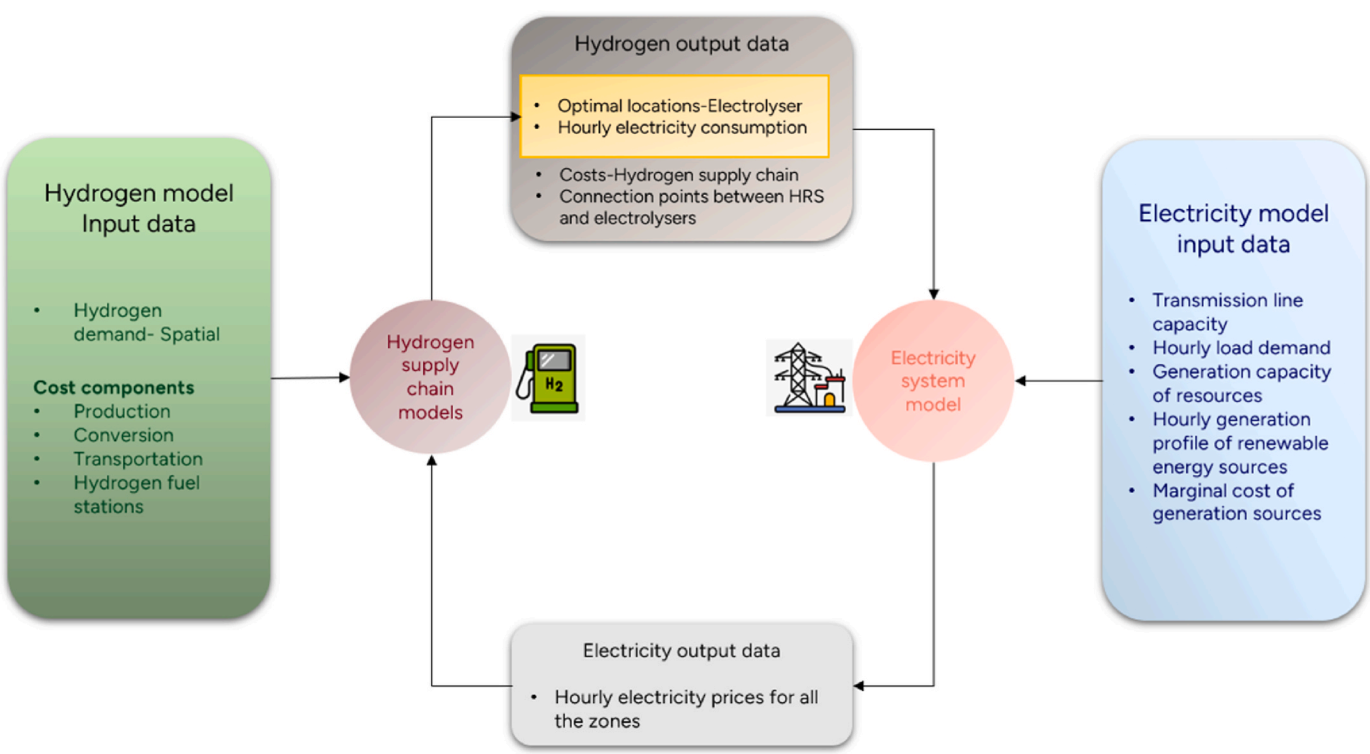

Fig. 1. Methodology overview: Models for the electricity system and the hydrogen supply chain, soft-linked through inputs and outputs.

TCC_s: Determines the transportation capital costs at state s, in €.
POC$_p$: Determines the production operating costs of electrolyser p, in €.
$COC_{p,s}$: Determines the conversion operating costs of electrolyser p at state s, in €.
SOC_s: Determines the fuel stations' operating costs at state s, in €.
$TOC_{p,f}$: Determines the transportation operating costs from electrolyser p to hydrogen fuel station f, in €.

Each cost is broken down into capital and operational cost components. All four components of capital costs include specific annual O&M costs ($O\&M$), and annuity factors (A) [22].

$$AF = \frac{(1+WACC)^d \times WACC}{(1+WACC)^d - 1} \tag{2}$$

where $WACC$ is the weighted average cost of capital in % and d is the individual depreciation years.

The electrolyser's capital costs are calculated as follows

$$PCC_p = \frac{IE \times ED \times Mhp_p}{EE} \times (1 + O\&M_E) \times AF_E \tag{3}$$

where.

IE stands for capacity-dependent investment costs, in $€/kW$.
Mhp_p stands for maximum hourly hydrogen production, in $kg_{H_2}/\ h$.
ED stands for hydrogen's energy density, in kWh_{H_2}/kg_{H_2}.
EE stands for the electrolyser efficiency, in kWh_{H_2}/kWh_{el}.

Conversion costs are only included when the supply chain design is modelled with liquid hydrogen transportation (as liquefaction costs are substantial) and are calculated as follows

$$CCC_{LH_2} = IC_{LH_2}(MDhp) \times \left(1 + O\&M_{C_{LH_2}}\right) \times AF_c \tag{4}$$

Where IC is capacity-specific investment costs in $€\ /\ kg_{H_2}$, and MD_{hp} is the maximum daily sum of converted hydrogen across all plants in $€/kg_{H_2}$.

Fuel station capital costs are calculated as follows

$$SCC_s = IS_s \times NFS \times (1 + O\&M_{S_s}) \times AF_s \tag{5}$$

Where IS is the investment cost of one fuelling station in €, and NFS is the number of fuelling stations.

Transportation capital costs are calculated as follows

$$TCC_s = ITRU \times NT \times (1 + O\&M_{TRU}) \times AF_{TRU} + ITRA_s \times NT \times \left(1 + O\&M_{TRA_S}\right) \times AF_{TRA} \tag{6}$$

Where NT is the number of trucks and trailers, $ITRU$ is the investment per truck in € and $ITRA$ is the investment per trailer in €.

Production operating costs are calculated as follows

$$POC_p = \sum_{t \in T} hp_{p,t} \times ECP \times EP_{p,t}\ \forall\ p \in P \tag{7}$$

Where, $hp_{p,t}$ is hourly hydrogen output in kg_{H_2}, ECP is the electricity consumption in kWh_{el}/kg_{H_2} and EP_p is the location specific electricity price in $€/kWh_{el}$.

The operating costs of converting hydrogen is calculated as follows

$$COC_{p,LH_2} = \sum_{t \in T} hp_{p,t} \times EC_{liquefaction} \times EP_{p,t} \times \left(1 + Loss_{liquefaction}\right) + \sum_{t \in T} hp_{p,t} \times EC_{evaporation} \times EP_{p,t} \times \left(1 + Loss_{evaporation}\right)\ \forall\ p \in P \tag{8}$$

Where hp_p is the daily hydrogen throughput in kg_{H_2}, $EC_{\text{liquefaction}}$ and $EC_{\text{evaporation}}$ are the electricity required for liquefaction and evaporation both in kWh_{el}/kg_{H_2}.

The fuelling station operating costs are given by

$$SOC_s = (ECS_s \times EP) \times (1 + Loss_s) \times \sum_{p \in P} \sum_{t \in T} hp_{p,t} \tag{9}$$

Where ECS_s is the output-dependent consumption of electricity in kWh_{el}/kg_{H_2}, and EP is the respective price in $€/kWh_{el}$,

At last, the transportation operating costs are made up of labour costs (LC), and fuel and toll costs (FCT). The fuel costs are

$$TOC_{p,f} = \left(LC_{p,f} + FCT_{p,f}\right) \times 365 \tag{10}$$

Labour costs (LC) are given by

$$LC_{p,f} = \left(2 * DT_{p,f} * W\right) * \frac{HRS_{cap}}{T_{caps}} \tag{11}$$

Where DT is driving time in h, W is hourly wage in €/h, HRS_{cap} is HRS capacity and T_{caps} is trailer's capacity. DT is further given by

$$DT_{p,f} = TD_{p,f} * 1.3\ /\ DS \tag{12}$$

Where $TD_{p,f}$ is the transport distance between matched electrolysers and fuelling stations in km and DS is average driving speed in km/h.

Fuel and Toll Costs are given by

$$FCT_{p,f} = 2 \times TD_{p,f}\ \times 1.3 \times Y_{p,f} \times (FC \times FP + TC) \times HRS_{cap}/T_{cap} \tag{13}$$

Where FC is fuel consumption in $€\ /kg_{H_2}$, FP is fuel price in €/kgH$_2$, and TC is toll cost in €/km, and $Y_{p,i}$ is a variable that is equal to 1 if transportation between electrolyser p and hydrogen fuel station f has been established and 0 otherwise.

The constraints considered for the model include.

- Daily transportation volume $ht_{d,p,f}$ between an electrolyser p and a hydrogen fuelling station f meets the daily demand of a fuelling station $SCAP_d$;

$$ht_{d,p,f} = SCAP_d \times y_{p,f} \quad \forall\ d \in D, p \in P, f \in F \tag{14}$$

- The transportation volume at a given day d must satisfy the hydrogen demand across all the hydrogen refuelling stations;

$$\sum_{d \in D} ht_{d,p,f} \geq SCAP_d \times NFS\ \forall\ p \in P, f \in F \tag{15}$$

- Minimum and maximum hydrogen output from an electrolyser is within the installed capacity limits;

$$t_1 = d*24 \quad \forall\ d \in D \tag{16}$$

$$t_2 = (d+1)*24 \quad \forall\ d \in D \tag{17}$$

$$\sum_{t_1}^{t_2} hp_{p,t} \geq \sum_{f \in F} ht_{d,p,f} \quad \forall\ d \in D, p \in P \tag{18}$$

- The hydrogen output $hp_{p,t}$ depends on its installed capacity which is between a fixed minimum and maximum capacity $HPCAP$.

$$HPCAP_{\min} * x_{p,t} \leq hp_{p,t} \leq HPCAP_{\max} * x_{p,t} \quad \forall\ p \in P \tag{19}$$

- At any fuelling station, the entire demand is covered by one electrolysis plant

$$\sum_{p \in P} y_{p,f} = 1 \quad \forall\ f \in F \tag{20}$$

- The connection between an electrolyser p and the fuel station f can only exist if the driving time is less than 12 h. This is to ensure that truck has sufficient time to refuel the hydrogen fuel station once a day.

$$DT_{p,f} > 12 \Rightarrow y_{p,f} = 0 \quad \forall p \in P, f \in F \tag{21}$$

2.2. Decentralised hydrogen supply chain model

The objective function in this model changes to

$$\sum_{f \in F} PCC_f + SCC_s + \sum_{f \in F} POC_f + SOC_s \tag{22}$$

The equations for the cost components remain the same as in the centralized model, apart from the index, which changes to f, since there is on-site production. Therefore, the on-site production capital and operational costs are calculated as

$$PCC_f = \frac{IE \times ED \times Mhfs_f}{EE} \times (1 + O\&M_E \times AF_E) \tag{23}$$

$$POC_f = \sum_{t \in T} hfs_{f,t} \times ECP \times EP_{f,t} \, \forall f \in F \tag{24}$$

Where.

PCC_f is the on-site production capital costs and POC_f is the on-site production operational costs, SCC is the capital cost of the fuel stations in € and SOC is the operational cost of the fuel stations in €.

In addition to the constraints used in the centralised model, the following constraints are considered in this model.

- The daily demand of every hydrogen fuelling station f must be satisfied by the on-site electrolyser at that same fuel station.

$$\sum_{t_1}^{t_2} hp_{f,t} \geq SCAP_d \quad \forall f \in F, d \in D \tag{25}$$

2.3. Mixed hydrogen supply chain model

The objective function in this model changes to

$$\sum_{p \in P} PCC_p + \sum_{f \in F} PCC_f + SCC_{GH_2} + TCC_{GH_2} + \sum_{p \in P} POC_p + \sum_{f \in F} POC_f + SOC_{GH_2} + \sum_{p \in P} \sum_{f \in F} TOC_{p,f} \tag{26}$$

There is a slight change within the transportation capital cost, in comparison to the centralised design, concerning the number of trucks and trailers. In the centralised design, the number of trucks and trailers is assumed to be the same as fuel stations. However, in the mixed design that is not the case as there may be on-site production. Hence, the number of trucks and trailers is given by equation (15)

$$NT = \sum_{p \in P} \sum_{f \in F} y_{p,f} \tag{27}$$

In addition to the constraints used in centralised model, the following constraints are considered in this model.

- The daily demand can be different depending on the day hence to account for seasonal variation

$$ht_{d,p,f} = SCAP_d \times y_{p,f} \quad \forall d \in D, p \in P, f \in F \tag{28}$$

- The on-site hydrogen production must satisfy the daily demand of hydrogen fuel station f if on-site production is chosen.

$$aux_{d,f} = SCAP_d \times select_f \quad \forall f \in F, d \in D \tag{29}$$

$$\sum_{t_1}^{t_2} hfs_{f,t} \geq aux_{d,f} \quad \forall f \in F, d \in D \tag{30}$$

- Sum of all centralised and decentralised production must satisfy the daily hydrogen demand.

$$\sum_{p \in P} \sum_{f \in F} ht_{d,p,t} + \sum_{f \in F} aux_{d,f} \geq SCAP_d {*} NFS \quad \forall d \in D \tag{31}$$

- The entire demand of a fuel station can be covered by at most one electrolysis power plant p.

$$\sum_{p \in P} y_{p,f} \leq 1 \quad \forall f \in F \tag{32}$$

The hydrogen production prompted by the hydrogen models in turn affects the electricity demand on the network. This extra electricity can have impacts on the electricity system driving prices higher. The goal of this analysis is to evaluate quantitively, the changes in the electricity system as a result of the hydrogen production demand. The impact on certain zones will be more pronounced than others due to the difference in electricity prices as well as the demand for hydrogen. Hence, the electrolysers' locations and the respective electricity loads are fed back into the electricity system model to measure the impacts of the hydrogen demand on the electricity prices.

2.4. Sensitivity analysis

To comprehend the effects of significant price disparities between zones SE3, SE4, and SE2, prices in zones SE3 and SE4 were doubled. The main purpose of conducting this sensitivity analysis in the centralized design is to understand how the optimization of the electrolysers' locations will be influenced when most of the hydrogen refuelling stations (HRS) are situated in zones SE3 and SE4. On the other hand, the decentralised model offers an intriguing insight into how much the overall supply chain cost would rise if the electrolysers were placed at the same site as the HRSs. Lastly, this analysis provides valuable information on how it impacts the mixed model, possibly leading to decentralised production in zones SE1 and SE2, while the electrolyser facilities for HRS in zones SE3 and SE4 will be located in zone SE2.

3. Data

This section outlines the relevant data, the steps to process the data and the assumptions for hydrogen demand, hydrogen production and transportation, and the electricity system. A tabulated summary of data is also provided in Appendix-1.

3.1. Hydrogen demand data

The number of anticipated fuel cell electric trucks is calculated based on the research of The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) and the European Commission - DG Energy, the hydrogen demand in 2030 for trucks and passenger vehicles is determined [23]. This is then used alongside average consumption of 8 and 0.63 $kg_{H_2}/100\,km$ [24,25] and average mileage of 40,410 and 11,000 km in a year [26] to calculate the annual hydrogen demand for heavy-duty trucks and passenger vehicles, respectively. The estimated hydrogen daily demand must be spatially divided. In this case, this was spread according to the population density of each county of Sweden. As mentioned, every hydrogen supply chain design was parameterized as two scenarios: with and without seasonal variation.

- Scenario A without seasonal variation: Under this scenario, the daily hydrogen demand is calculated by dividing the annual hydrogen demand by the number of days in a year (365). This results in an estimate of average daily hydrogen demand of 63.7 tons and 19.7 tons for heavy-duty trucks and passenger automobiles, respectively.
- Scenario B with seasonal variation: According to the study performed by Vepsäläinen et al. [27] on battery electric buses, the consumption is dependent on outdoor ambient temperature and provide a graph highlighting the fluctuation of energy demand with ambient temperature. This work was further developed by Jacob [28] arriving at an equation to calculate the hydrogen demand of a fuel cell electric bus as shown below

$$FCEB_{consumption} = \left(3.84\times10^{-6}T^3 + 2.14\times10^{-4}T^2 - 6.84\times10^{-2}T + 1.0397\right) \tag{33}$$

where $FCEB_{consumption}$ is the energy demand of fuel cell electric bus and T is the ambient temperature in °C.

The data on ambient temperature is acquired from the Swedish Meteorological and Hydrological Institute (SMHI). The Örebro municipality was used as a reference to get the ambient temperature variance as it is located in the centre of the South of Sweden where most of the traffic is concentrated. The daily average consumption per 100 km calculated using equation (33) was 6.71 kg_{H_2} which is less than the national average of 8. The profile was therefore multiplied by 8/6.71 to achieve a consistent national average. The same was repeated for passenger vehicles.

It is assumed that by 2030, all HRS will become L-size, i.e. maximum throughput capacity is 1000 kg/day [21]. The required number of HRS per county is calculated by dividing the fuel station's maximum throughput capacity by daily hydrogen demand. This results in 90 and 109 HRS for scenarios without and with seasonal variation in daily demand. The capital costs of HRS are calculated using the values and equation given in Ref. [21] which are shown in Table 2.

For heavy-duty trucks, the location of HRS is preferred to be as close to highways as possible and existing petrol fuel stations are preferred over new sites. Hence, OpenStreetMap was used to acquire both the locations of existing petrol fuel stations and highways in each county. A second criterion of minimum distance between two HRS was considered to ensure no clustering. This minimum distance was dependent on the size of the county and was set by trial and error manually for each county.

3.2. Hydrogen production and transportation data

For hydrogen production, proton exchange membrane (PEM) electrolysis is considered. Based on [29], it was expected that investment costs (IE) would be 500 €/kW_{el}, depreciation would take 10 years, O&M costs would be 3% of investment costs, and electricity consumption would be 47.6 kWh_{el}/kg_{H_2}. The minimum and maximum capacities of an electrolyser, respectively, for the centralized and decentralised models, were established at 10 MW and 100 MW for the former and 2 MW and 4 MW for the latter. For the centralised and mixed models, the potential locations for deploying centralised electrolysis plants were considered to be the locations of transmission grid substations.

The transportation of hydrogen via trucks was considered for the study. Delivery trucks load hydrogen into trailers and drive them to refuelling stations. A delivery truck's fuel consumption is fixed at 8 kg_{H_2}/100 km. In addition to fuel expenses, toll costs (0.15 €/km) and labour costs (20 €/h) for transportation were also included, based on [20,30]. Depreciation over an eight-year period, 160,000-euro investment cost per truck, and 12% O&M expenditures were also estimated. For the purposes of this study, it was assumed that the trailer could carry a maximum of 1000 kg_{H_2} in a gaseous form and 4000 kg_{H_2} in a liquid condition. Additionally, each truck can only deliver hydrogen to one fuel station, and it takes less than 12 h to travel the distance between the electrolyser and the HRS.

Table 2
Investment cost per hydrogen fuel station according to its state.

State	IC [M €] – seasonal variation	IC [M €] – without seasonal variation
$H_2(g)$	1.38	1.36
$H_2(l)$	1.77	1.74

3.3. Electricity system data

Sweden's electricity market is divided into four "bidding zones," or price ranges, called SE1, SE2, SE3, and SE4. To recreate hourly electricity costs for each zone and provide inputs for the hydrogen models, the electricity system was studied.

The PyPSA-eur model, which builds the transmission grid model by extracting it from the ENTSO-E interactive map of the European power system, was used to model the transmission grid [31]. Future grid extensions should be accounted for in the model since this study is being done for a 2030 scenario. We estimate the total transmission capacity of all 220 kV lines to be 490 MW and that of all 380–400 kV lines to be 1700 MW based on [32,33].

3.3.1. Hourly load demand

Data provided by ENTSO-E [34] was used to predict the hourly load demand in each zone for 2030. ENTSO-E presents hourly load demand predictions for 2030 considering three distinct scenarios. In this case, the "EUCO30" scenario was selected, which assumes that the 2030 climate and energy targets as established by the European Council in 2014 were reached. Based on the aforementioned estimate, Sweden will have a total power demand of 159 TWh in 2030. The acquired hourly load demand series is based on bidding zones.

3.3.2. Electricity generation from renewable energy sources (RES)

For deriving the temporal distribution of electricity generation from renewable energy sources (RES) in Sweden, a generation profile of solar and wind was built by using historical generation data. A global report demonstrates that during 11 years, solar and wind power will rise at annual compound growth rates (CAGR) of 16% and 8.3%, respectively [35] which is considered in the study. Hourly generation data was imported from ENTSO-E and PVGIS.

The electricity generation must be spatially distributed and assigned to transmission grid nodes. Nuclear and fossil-based power plants are already assigned to the respective transmission grid nodes through the PyPSA-Eur model. The bio-energy power plants in Sweden included in the PyPSA-Eur model are very scarce and the total installed capacity is very far from reality. Energiföretagen, has divulged in the report [36] the installed capacity of bio-energy power plants in each bidding zone of Sweden. This data does present one limitation: on occasions when there is a great need for district heating some of the capacity is diverted from electricity generation to heat generation. This fact was not considered and it is assumed that the entire capacity is available at any time for electricity generation. The bio-energy installed capacity is 272 MW, 682 MW, 2816 MW and 1549 MW for zones SE1, SE2, SE3 and SE4 respectively.

Despite knowing roughly how much wind capacity should be installed by now, there is also a lack of available information regarding wind turbines' locations, coordinate-wise, and corresponding capacities. The most detailed available source is OpenStreetMap, which is susceptible to incomplete and inaccurate information. Using the overpass-turbo tool, wind turbines were filtered from OpenStreetMap, resulting in a total of 3882 wind turbines. This number is not in accordance with the official source [37], which states that by July 2021 more than 4000 had been deployed in Sweden. Even though there is this discrepancy from OpenStreetMap, due to the lack of better sources, the wind turbines' locations from OpenStreetMap were used to spatially distribute wind capacity. Some wind turbines, besides providing coordinates, also indicate the corresponding capacities. However, the vast majority don't, which makes it impossible to know how much wind capacity still needs to be distributed in order to reach the 2030 target. Therefore, it was assumed that the wind turbines had been deployed by the end of 2021 resulting in a total capacity of 10.6 GW according to the CAGR formula. Thus, the capacity for the wind turbines without known capacity was assumed to be 2.6 MW so the sum of all wind turbines yielded the respective 10.6 GW. Afterwards, each wind turbine was assigned to its closest node using the Haversine formula which allowed us to compute how much capacity was assigned at each node. The wind capacity at each zone was distributed by scaling, evenly, the capacity of every node within each zone until the net capacity was achieved.

To run the electricity market model, the marginal costs of the available power plants must also be acquired which can be seen in Table 3. The marginal costs for solar and wind are assumed to be zero [38,39].

3.3.3. Electricity market model

The merit-order model was used to calculate the hourly electricity prices. The model aims to minimize the marginal generational costs, for each hour in each bidding zone. The constraints ensure that the electricity demand and supply are always met while considering the availability of electricity generation from different sources. The market model can thus be written as the following optimization problem

$$\text{Minimize } \sum_{c} \lambda_s \left(g_{s_{SE1}} + g_{s_{SE2}} + g_{s_{SE3}} + g_{s_{SE4}} \right) \tag{34}$$

subject to

$$d_{SE1} - \sum_{s} g_{s_{SE1}} = \Delta\delta_{SE1-SE2} : \lambda_{SE1}$$

$$d_{SE2} - \sum_{s} g_{s_{SE2}} = -\Delta\delta_{SE1-SE2} + \Delta\delta_{SE2-SE3} : \lambda_{SE2}$$

$$d_{SE3} - \sum_{s} g_{s_{SE3}} = -\Delta\delta_{SE2-SE3} + \Delta\delta_{SE3-SE4} : \lambda_{SE3}$$

$$d_{SE4} - \sum_{s} g_{s_{SE4}} = -\Delta\delta_{SE3-SE4} : \lambda_{SE4}$$

$$-8990 \leq \Delta\delta_{SE1-SE2} \leq 8990$$

$$-14580 \leq \Delta\delta_{SE2-SE3} \leq 14580$$

$$-12880 \leq \Delta\delta_{SE3-SE4} \leq 12880$$

Where.

λ_s is the marginal cost of the power source s.
$g_{s_{SEn}}$ is the generation of the power source s in zone SEn where n ranges from 1 to 4.
λ_{SEn} is the electricity price in bidding zone SEn where n ranges from 1 to 4.
$\Delta\delta_{SEn1-SEn2}$ is the transmission capacity between zones $SEn1$ and $SEn2$ [40].

Table 3
Marginal cost of the different electricity sources.

Technology	[€/MWhth]	VOM [€/MWh]	MC [€/MWh]
Solar	–	0	0
Wind	–	0	0
Hydro	–	–	6
Nuclear	2	8	10
Biomass	–	–	32.5
Oil	50	3	53

4. Results

In this section, the results of the electricity system, hydrogen supply chain design and impact of hydrogen demand are presented, analysed and discussed.

4.1. Electricity system model

The market model was run for 2030 and the resulting power mix in 2030 as against 2021 is shown in Fig. 2.

It can be clearly noted that hydro remains a major electricity generation source, alongside wind energy instead of nuclear as in 2021. In fact, the wind energy share grew from 17% to around 42%, whereas nuclear decreased from 30% to just 14%. Combined heat and power plants, which were mainly powered by bio-fuels, decreased from around 8% to less than 1%. Fossil fuels were not used at all. This means that by 2030, the Swedish electricity power industry should be almost fully decarbonised and provide green electricity as for the considered scenario in the study. Moreover, the average electricity price in €/MWh, is 4.28, 1.88, 8.21, 8.19 for zones SE1, SE2, SE3 and SE4, respectively. Furthermore, in 2030, the installed capacities, per source and per zone are shown in Fig. 3. The total installed capacity in 2030 is expected to be ~57.1 GW, much higher than the ~42 GW installed in 2021 [41].

4.2. Hydrogen supply chain

The hydrogen models discussed in the methodology produces.

- the location of HRSs,
- the optimized number and location of electrolysers, in the case of centralised models and mixed models,
- hourly hydrogen production rate,
- optimized transportation volume between each electrolyser and hydrogen fuel station, in case of centralised and mixed models, and
- the resulting hydrogen prices.

Fig. 4 shows the volume of hydrogen demand for gaseous state transport under the different scenarios. When seasonal variation is included, the demand variation is dependent on the type of transport model chosen. However, the annual average demand is assumed to be the same as in the scenario without seasonal variation.

Fig. 5 shows the hydrogen supply chain infrastructure for the centralised design without seasonal variation. The red dots represent the electrolysers, the blue squares represent the HRSs and the black lines

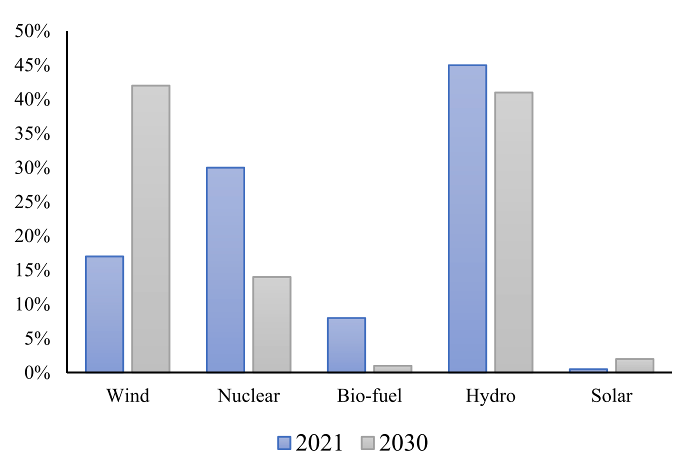

Fig. 2. Swedish power mix in 2030 and 2021.

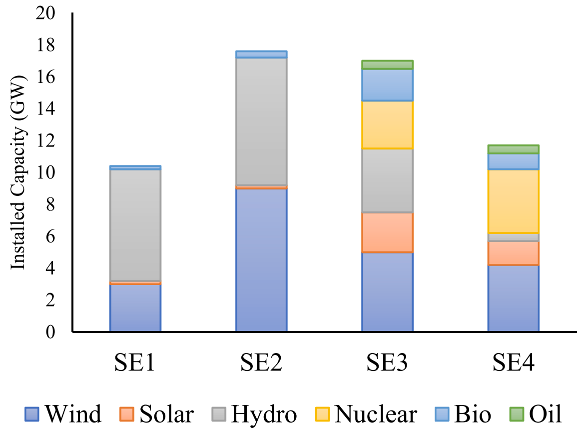

Fig. 3. Installed capacity by source in each zone in 2030.

represent the connections established. There is a substantial difference in the location of electrolysers depending on the state of hydrogen. It can be observed from the figures that, in the design with liquid state hydrogen transport, there are no electrolysers in zone SE3, contrary to the design with gaseous state hydrogen transport. Two major electrolysers located in SE2 supply all the HRSs in SE3. The installed capacity of those two electrolysers is 99 MW and 22 MW. This advantage stems from significantly reduced transportation costs, as a single trailer of liquid hydrogen can transport up to four times the amount of hydrogen as a trailer of compressed gaseous hydrogen, making it a more efficient and cost-effective option for long-distance hauls. Thus, it pays off to move more hydrogen production to zone SE2 where electricity prices are almost one-fourth the electricity prices in SE3.

Furthermore, by analysing the hourly production data, it was identified that seasonal variation increased the required electrolyser capacity. In the scenario without seasonal variation, the net electrolyser installed capacity was 190 MW and 249 MW for gaseous and liquid hydrogen transportation respectively. When seasonal variation was included, the net installed capacity increased to 303 MW and 325 MW respectively. This increase is a result of the days with higher demand arising from the weather conditions. In the centralised design in the gaseous state without seasonal variation, the number of electrolysers was 16, with sizes ranging from 10 MW to 26 MW and a capacity factor of 100%. For the same design but with seasonal variation, the number of electrolysers was 18, with sizes ranging from 10 MW to 70 MW and a capacity factor ranging from 77% to 80%. In the centralised design in the liquid state, the electrolysers' sizes ranged from 10 MW to 99 MW with capacity factors from 70% to 80%, however, the number of

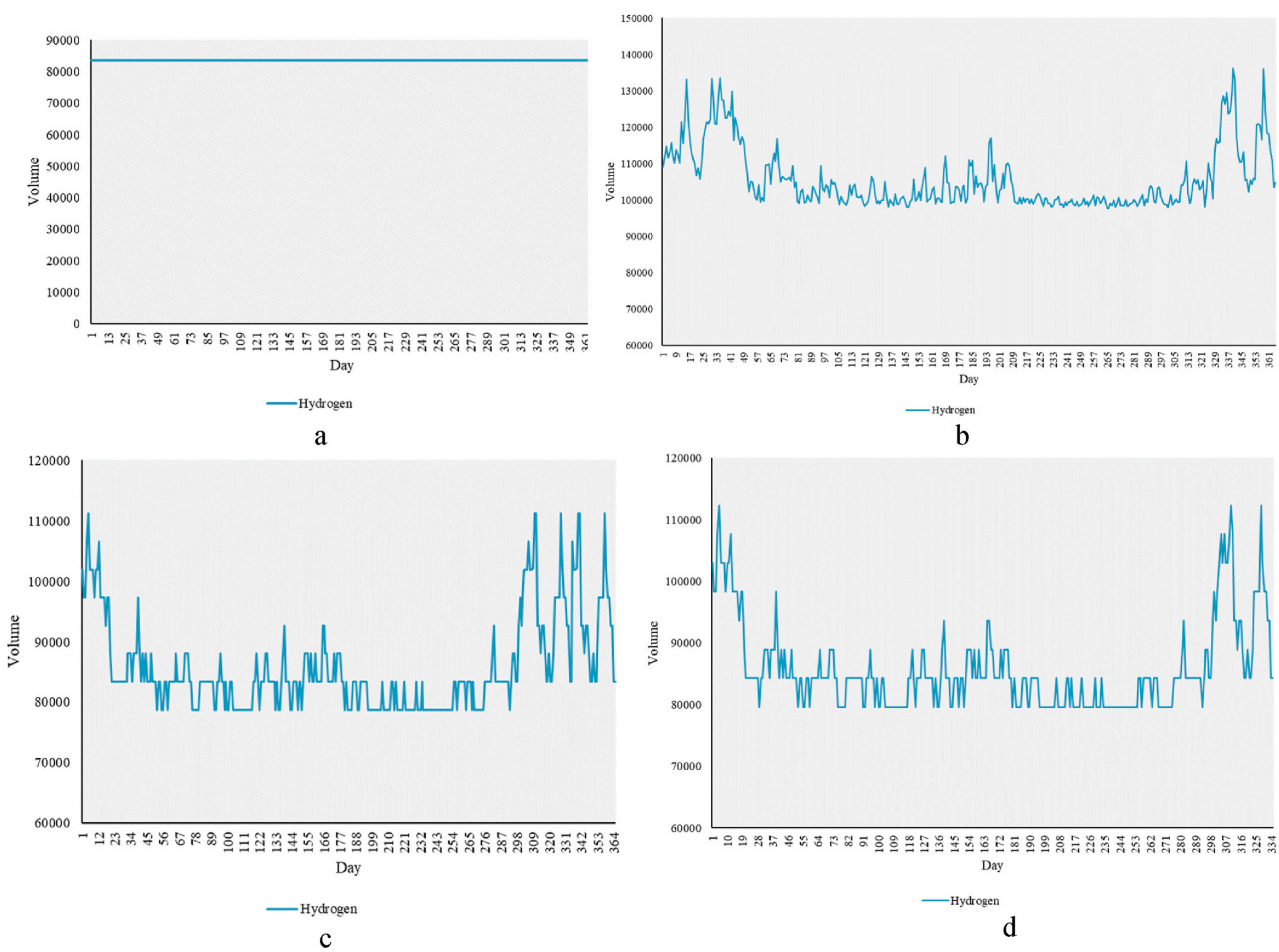

Fig. 4. Volume of hydrogen demand under the different scenarios for gaseous state: (a): With no seasonal variation; (b) Centralised production of hydrogen with seasonal variation; (c) Decentralised production of hydrogen with seasonal variation and (d) mixed production model with seasonal variation.

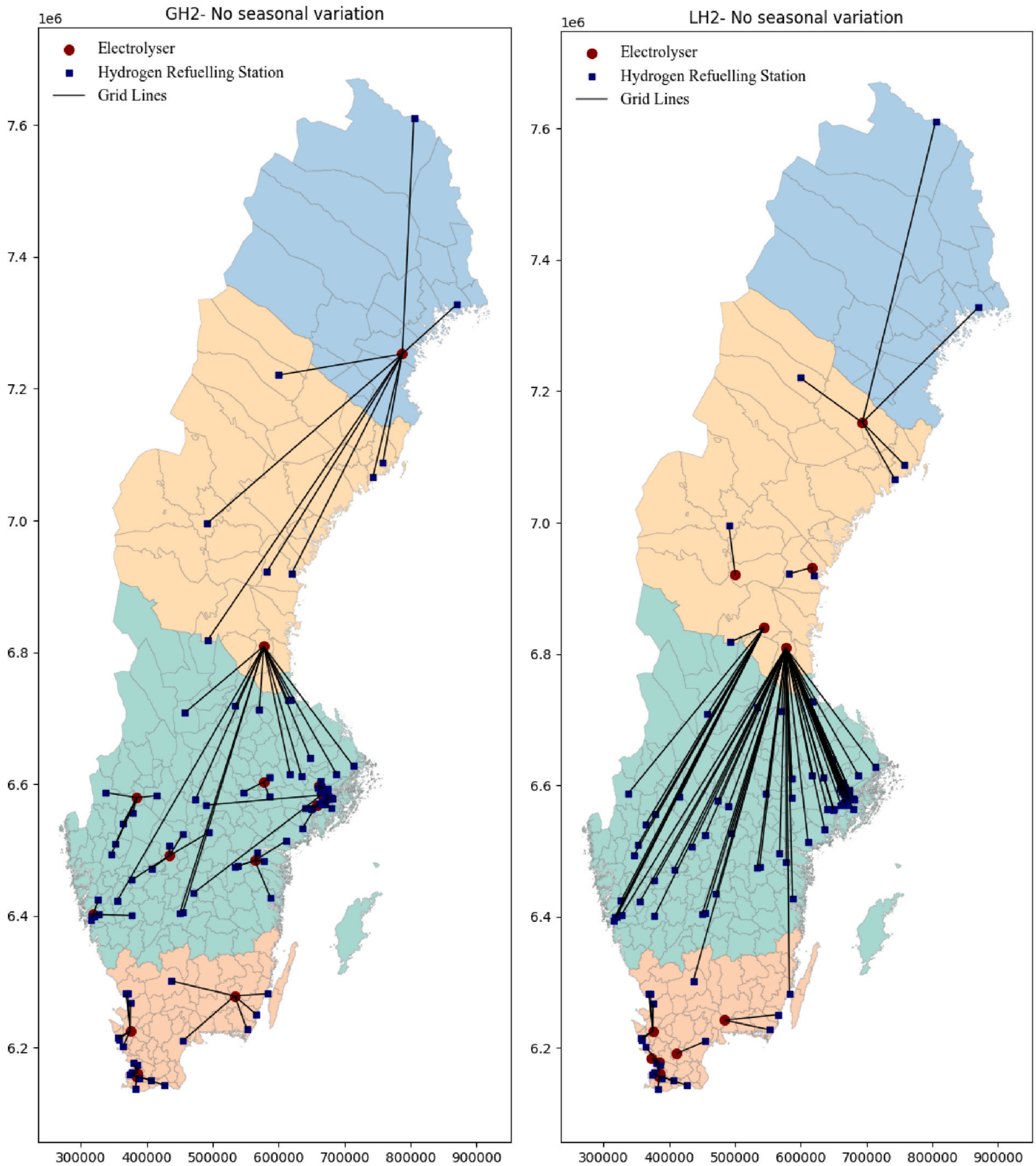

Fig. 5. Electrolysers' locations and connections to the HRSs they supply – centralised design in (a) gaseous state and (b) liquid state without seasonal variation.

electrolysers increased from 9 to 19 when seasonal variation was accounted for.

In the decentralised design without seasonal variation, the size of the electrolyser was the same for every HRS, roughly 1.8 MW, and they were operational every hour. When seasonal variation was included, the electrolyser capacity increased to roughly 2 MW. However, these electrolysers were not operational the entire time, the capacity factor was only slightly above 78%.

Production capital costs and fuel station capital costs are the largest expenses in the centralised design, irrespective of the state of transport or seasonal variation, as shown by the charts in Fig. 6. In centralised design, production capital costs increase when seasonal variation is included for both gaseous and liquid hydrogen transport. Despite having reduced transportation operational costs, the centralised approach in its liquid state is always more expensive than in its gaseous state due to conversion expenses. The model's assumption that an HRS is supplied by a single truck results in an increase in transportation capital costs.

The overall costs of decentralised design are lower than the overall costs of the centralized design, as seen in Fig. 7. The figure shows that this is a result of transportation expenses in the centralized design, and in the case of the centralized supply chain design in the liquid state, there are additional conversion expenses. Decentralised design is not considered with liquid state transport as all hydrogen is locally produced at the HRSs.

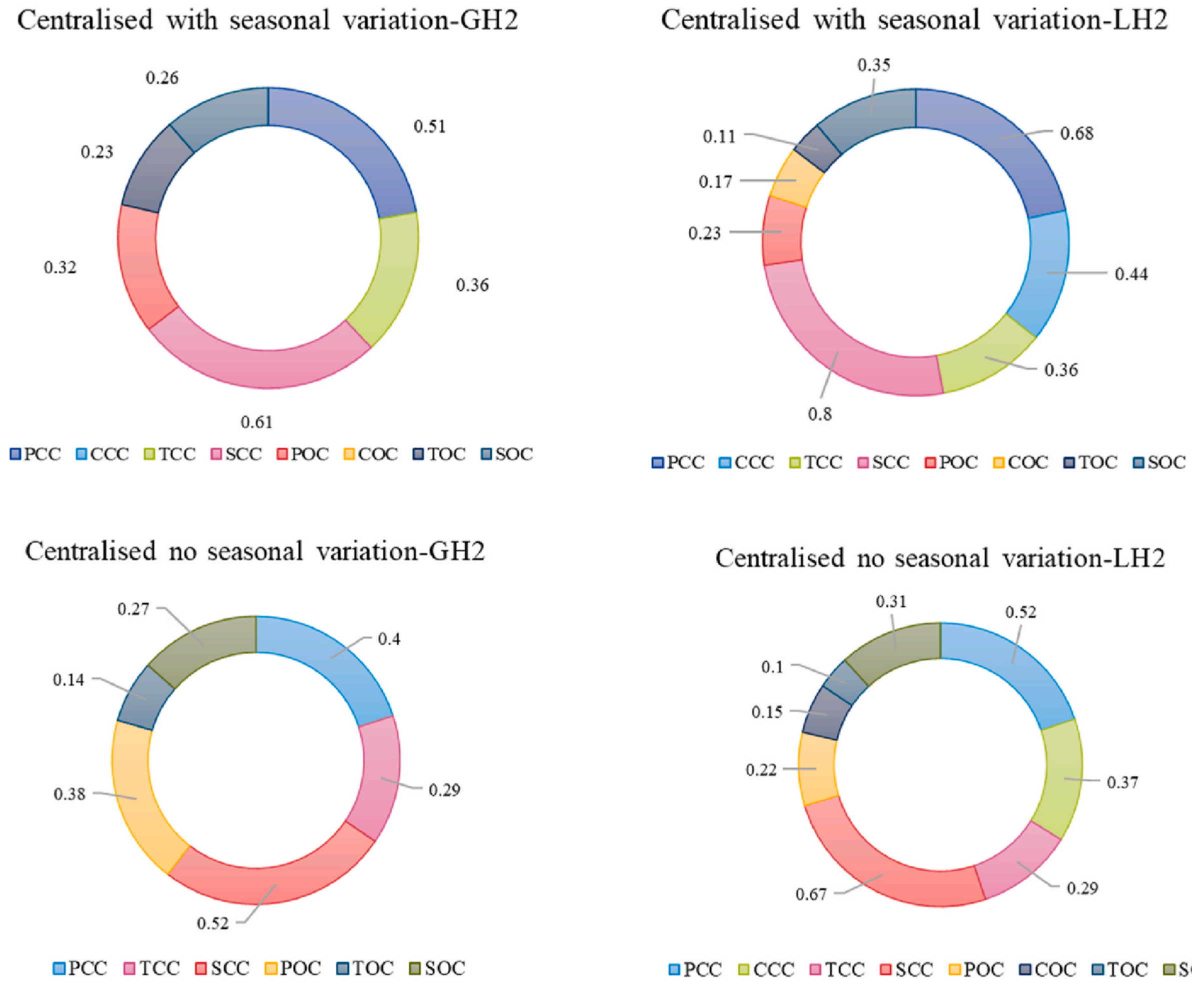

Fig. 6. Hydrogen cost component, in €/kg, for the centralised model for liquid state and gaseous state without and with seasonal variation (PCC- Production capital cost, CCC-Conversion capital cost, TCC-Transportation capital cost. SCC- Fuel Station capital cost, POC-Production operating cost, COC-Conversion operating cost, TOC-Transportation operating cost, SOC- Station operating cost).

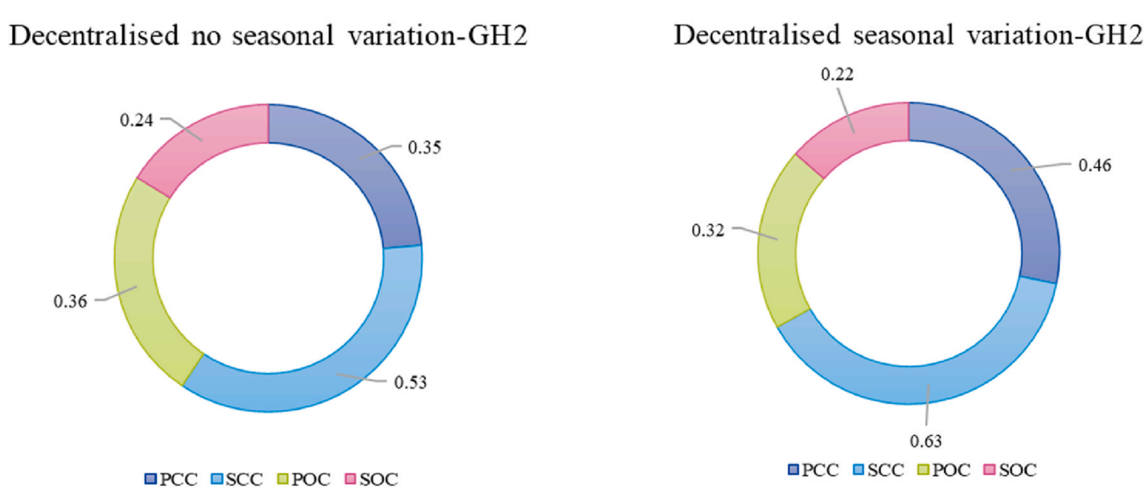

Fig. 7. Hydrogen cost component, in €/kg in the decentralised model with and without seasonal variation for gaseous state (PCC- Production capital cost, SCC- Fuel Station capital cost, POC-Production operating cost, SOC- Station operating cost).

Fig. 8 shows the hydrogen cost components in a mixed model with and without seasonal storage. The capital costs in mixed model scenario are higher than that in the centralised scenario and decentralised scenario under no seasonal variation. However, when considering the seasonal variations, the capital cost is lower than the centralised scenario and is comparable to the decentralised scenario.

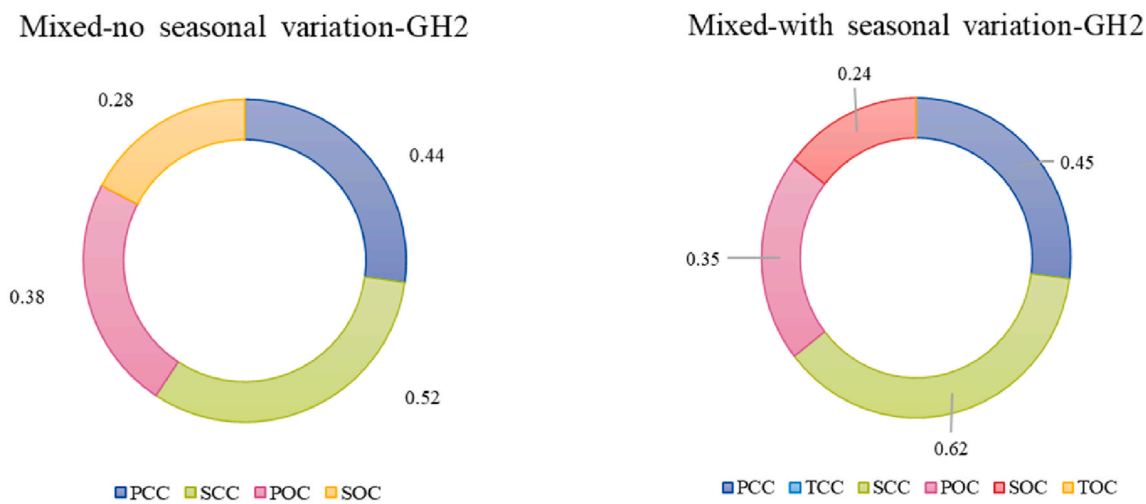

Fig. 8. Hydrogen cost component, in €/kg in a mixed model with and without seasonal variation for gaseous (PCC- Production capital cost, TCC-Transportation capital cost. SCC- Fuel Station capital cost, POC-Production operating cost, TOC-Transportation operating cost, SOC- Station operating cost).

4.3. Feedback and sensitivity analysis

In terms of impact on prices, it can be said that the demand for hydrogen does have a sizable effect on the cost of energy as can be seen in Tables 4 and 5. Additionally, the decentralised model has a greater influence on costs in zones SE3 and SE4 than the centralized model does, given that zones SE3 and SE4 are home to the majority of the electrolysers.

In the centralised design in the gaseous state, production operational costs decreased since more hydrogen was produced in zone SE2, which led to an increase in transportation operational costs. In the centralised design in the liquid state, the increase in the overall cost was mainly due to an increase in production operational costs from the electrolysers in zone SE4. Transportation operational costs remained the same. In short, the centralised design in the gaseous state increased transportation costs (moved hydrogen production from SE3 to SE2) to decrease production operational costs and achieve a minimum overall cost. Table 6 shows the changes in costs due to the sensitivity analysis of the centralised design. These changes can be further analysed in comparison to Fig 5 and Fig 9 which shows that the electrolysers located in SE3 no longer exist when the electricity prices are doubled in zones SE3 and SE4. In fact, the HRSs that were supplied by those electrolysers are now supplied by either one of the electrolysers located above Stockholm, in zone SE2. There are no major differences in design with liquid hydrogen transportation.

The same sensitivity analysis was carried out for both the decentralised and mixed designs without seasonal variation. Contrary to the centralised design, the decentralised design does not have the option to shift its production facilities to zones with cheaper prices. Therefore, production operational costs increased much more than in the centralised design, actually doubling, leading to an increase in the overall cost of 0.36 €/kgH_2, as can be seen in Table 7. In the mixed design, it is quite interesting to observe that now there are transportation costs. This can be explained by the difference in electricity prices, particularly between zones SE3 and SE2, it paid off to have some centralised production in zone SE2 supplying four HRSs in zone SE3.

Table 4
Increase of electricity price, in €/MWh, regarding scenario with seasonal variation.

	Design	Centralized				Decentralised	
	Annual avg. elec. price	$H_2(g)$		$H_2(l)$		$H_2(g)$	
SE1	4.28	4.41	3.04%	4.28	0.00%	4.32	0.93%
SE2	1.88	2.02	7.45%	2.35	25.00%	1.92	2.13%
SE3	8.21	8.49	3.41%	8.47	3.17%	8.37	1.95%
SE4	8.19	8.47	3.42%	8.45	3.17%	8.35	1.95%

Table 5
Increase of electricity price, in €/MWh, due to the hydrogen demand without seasonal variation.

	Design	Centralized				Decentralised	
	Annual avg. elec. price	$H_2(g)$		$H_2(l)$		$H_2(g)$	
SE1	4.28	4.37	2.10%	4.28	0.00%	4.32	0.93%
SE2	1.88	1.94	3.19%	2.34	24.47%	1.92	2.13%
SE3	8.21	8.40	2.31%	8.44	2.80%	8.37	1.95%
SE4	8.19	8.38	2.32%	8.42	2.81%	8.35	1.95%

Table 6
Hydrogen supply chain cost changes regarding the centralised design, in €/kgH_2, for the sensitivity analysis with doubled electricity prices in zones SE3 and SE4.

	$H_2(g)$		$H_2(l)$	
	Without sensitivity	With sensitivity	Without sensitivity	With sensitivity
Sum	2.00	2.24	2.63	2.76
PCC	0.40	0.46	0.53	0.51
CCC	0.00	0.00	0.37	0.37
TCC	0.29	0.29	0.29	0.29
SCC	0.52	0.52	0.67	0.67
POC	0.38	0.35	0.22	0.32
COC	0.00	0.00	0.15	0.17
TOC	0.14	0.30	0.10	0.10
SOC	0.27	0.32	0.31	0.33

4.4. Discussion

The aim of this study is threefold: optimization of the hydrogen supply chain, analysis of the impact of the hydrogen supply chain on the electricity market, and investigation of the renewable energy requirements to meet the hydrogen demand. To achieve this, a single futuristic scenario focused on the year 2030 is considered, driven by the availability of government plans and data for this time frame. This decision allows us to provide more accurate and detailed results, despite

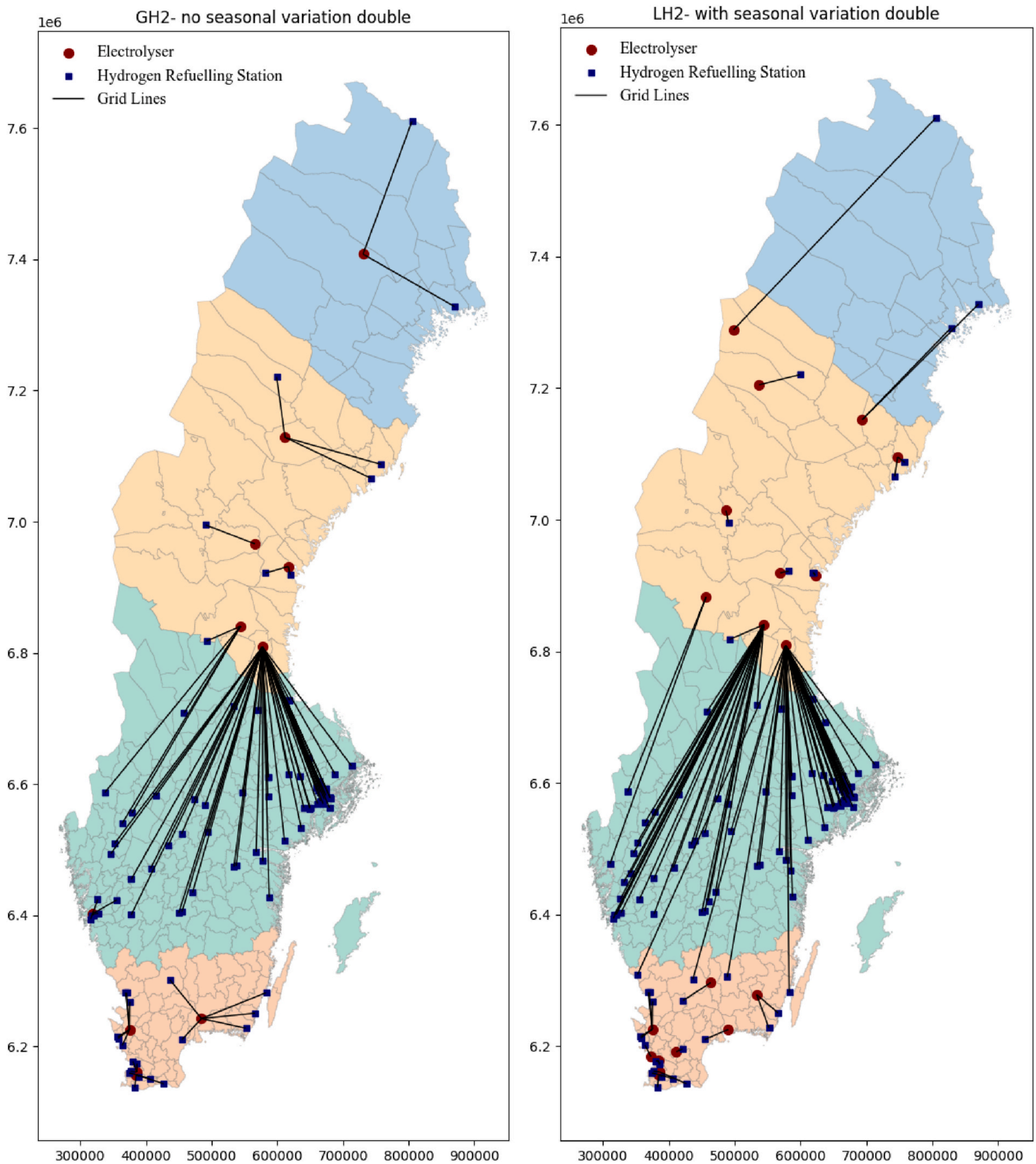

Fig. 9. Electrolysers' locations and connections to the HRSs they supply, with doubled prices in SE3 and SE4 – centralised design (a) in the gaseous state with no seasonal variation and (b) in the liquid state with seasonal variation.

acknowledging that it may not fully capture the long-term dynamics of energy markets, as it aligns with Sweden's national plans.

In the centralized design in the gaseous state, there was a reduction in production operational costs due to increased hydrogen production in zone SE2. However, this led to higher transportation operational costs. On the other hand, in the centralized design with a liquid state, the overall cost increase was primarily driven by higher production operational costs from the electrolysers in zone SE4, while transportation operational costs remained unchanged. In summary, the gaseous state centralized design increased transportation costs by shifting hydrogen production from SE3 to SE2, aiming to minimize overall costs. Conversely, the liquid state centralized design already had most of its electrolysers in SE2, benefiting from lower electricity prices, resulting in unchanged transportation operational costs, but increased production operational costs due to the electrolysers located in SE4. The electrolysers previously situated in SE3 are no longer in operation when the electricity prices in zones SE3 and SE4 are doubled. Consequently, the hydrogen refuelling stations (HRSs) that were originally supplied by these electrolysers are now being served by either of the two electrolysers located above Stockholm in zone SE2. On the other hand, in the centralized design in the liquid state, there is no significant difference between them.

Table 7
Hydrogen supply chain cost changes regarding the decentralised and mixed designs, in €/kgH_2, for the sensitivity analysis with doubled electricity prices in zones SE3 and SE4.

	Decentralised		Mixed	
	Without sensitivity	With sensitivity	Without sensitivity	With sensitivity
Sum	1.48	1.83	1.48	1.83
PCC	0.35	0.35	0.35	0.54
CCC	0.00	0.00	0.00	0.00
TCC	0.00	0.00	0.00	0.04
SCC	0.53	0.53	0.53	0.52
POC	0.36	0.72	0.36	0.50
COC	0.00	0.00	0.00	0.00
TOC	0.00	0.00	0.00	0.01
SOC	0.24	0.24	0.24	0.23

As can be seen, power prices are quite cheap; but, if the model included uncertainty from RES, the prices would vary. It would be interesting to investigate the intraday market to see how the market would respond to such adjustments. Additionally, these restrictions result in non-existent negative pricing, which is quite intriguing to include, especially when researching a hydrogen supply chain with storage. The hydrogen model's accuracy is increased by integrating time-flexible operation but at the cost of making the optimization problem more difficult and perhaps requiring a machine with very high specifications. A 15% allowable gap in the optimization was defined for the centralized and mixed designs. The centralised models typically required longer than a day to run with such an allowed gap. The optimizations needed to be run on a computer with 256 GB of RAM due to the complexity of the designed model.

This work does have some limitations. The model of the electrical system does not include.

- Cross-border power exchange.
- Uncertainty around the need for power and renewable energy sources.
- The ramp-up times for the generation sources and other technical details pertaining to the various technologies.
- Variations in fuel prices.
- The adoption of measures that alter the marginal costs.
- The electricity market model developed in this study is simplistic in nature, as the primary focus was on the detailed optimization of the hydrogen supply chain. While the model does not explicitly account for energy storage, the data used from the Swedish government's 2030 plans does factor in the planned expansion of storage capacity.

5. Conclusion

The average electricity prices in Sweden for zones SE1, SE2, SE3 and SE4 are, in €/MWh, 4.28, 1.88, 8.21, and 8.19 respectively. The electricity is mainly generated from wind and hydropower (around 42% each), followed by nuclear (14%), solar (2%) and then bioenergy (0.3%). The main changes in the power mix are the huge increase in wind power generation, the decrease in nuclear power generation, and particularly, the Swedish power mix is solely made up of RES.

The hydrogen supply chain design that leads to a lower overall cost is the decentralised design, with a cost of 1.48 and 1.68 €/kgH_2 in scenarios without and with seasonal variation respectively. It is cheapest by a margin of 0.52 and 0.61 €/kgH_2 to the centralised design in the gaseous state, in what concerns the scenario without and with seasonal variation, respectively. It is important to highlight that for the centralised design, the achieved solution was just below 15% of the optimal solution, whereas for the decentralised design, the solution was quite close to the optimal solution. Therefore, taking that into account, the difference between the optimal solutions is 0.30 and 0.36 €/kgH_2, in scenarios without and with seasonal variation, respectively.

The scenario with seasonal variation leads to higher costs in the supply chain as more hydrogen fuel stations were deployed to meet days with higher hydrogen demand. This led to higher production capital costs (PCC) and fuel station capital costs (SCC) in every design, transportation capital costs (TCC) in the centralised design, and conversion capital costs (CCC) in the centralised design in the liquid state. It was also concluded that the centralised model is less sensitive to a scenario where the electricity prices in zones SE3 and SE4 are considerably higher than in zone SE2. The decentralised scenario is more sensitive since most of the HRSs are located in SE4 and, particularly, SE3, thus the electrolysers as well. In addition, increasing the hydrogen demand leads to a slightly lower supply chain overall cost in the decentralised design.

It can also be concluded that hydrogen demand does have a significant impact on electricity prices. Furthermore, in the centralised model, the impact on the prices is mainly on zones SE2, SE3 and SE4, whereas, for the decentralised model the impact is mainly in zones SE3 and SE4, which makes sense since that is where most of the electrolysers are located. The study's findings also indicated that the centralized model is less affected by a scenario where electricity prices in zones SE3 and SE4 are significantly higher than in zone SE2. In contrast, the decentralised scenario is more sensitive to such price differences, especially because the majority of the hydrogen refuelling stations (HRSs) are situated in SE4 and SE3, along with the electrolysers. Moreover, it was observed that an increase in hydrogen demand results in a slightly lower overall cost for the supply chain in the decentralised design.

In future research, there is a need to expand the electricity system model to overcome its current limitations and enable a more detailed examination of the synergies between different hydrogen supply chain designs and the electricity system. Introducing storage within the hydrogen supply chain could lead to overall cost reductions and electricity dispatch cost reductions if integrated into the electricity system model. By incorporating storage, the study could explore demand flexibility solutions. It is essential to note that this study offers a high level of geographical detail, focusing solely on Sweden as a closed system with no electricity or hydrogen exchanges with foreign entities. To gain a broader perspective, extending the analysis to a European context could be valuable, although it would require substantial additional modelling efforts.

CRediT authorship contribution statement

Jagruti Thakur: Writing – review & editing, Writing – original draft, Validation, Supervision, Software, Project administration, Methodology, Investigation, Formal analysis, Conceptualization. **José Maria Rodrigues:** Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Sivapriya Mothilal Bhagavathy:** Writing – review & editing, Writing – original draft, Resources, Methodology.

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.

Appendix 1. Data

The appendix presents the input data which is derived based on several resources.

Hydrogen demand data [24,26,27]		
	Heavy duty trucks	Passenger vehicles
Average mileage [km]	40410	11000
Number of vehicles	7200	103700
H2 annual demand [ton]	23276	7186
Scenario without seasonal variation		
Average daily consumption	63.7 tons	19.7 tons
Scenario with seasonal variation		
Daily average consumption per 100 km	8 kgH_2/100 km	0.63 kgH_2/100 km
	Without seasonal variation	With seasonal variation
Number of hydrogen fuel stations [21]	90	109
Investment cost per hydrogen fuel station according to its state in Million Euros [21]		
	Without seasonal variation	With seasonal variation
GH2	1.38	1.36
LH2	1.77	1.74
Hydrogen production data [29]		
Energy density of hydrogen	33.33 $kWhH_2/kgH_2$	
Investment costs IE	500 €/kWel	
Depreciation	10 years	
O&M costs	3% of investment costs	
Electricity consumption	47.6 $kWhel/kgH_2$	
	Centralized model	*Decentralised model*
$HPCAP_{min}$	10 MW	2 MW
$HPCAP_{max}$	100 MW	4 MW
Hydrogen Transportation data [20,21,30]		
Fuel consumption of a delivery truck		8 kgH_2/100 km
Toll costs		0.15 €/km
Labor costs		20 €/hour
investment cost per truck		160.000 €,
depreciation		8 years
O&M costs		12%
Trailer costs		660,000 € for $H_2(g)$, 860,000 € for $H_2(l)$
Trailer's maximum capacity		1000 kg $H_2(g)$, 4000 kg $H_2(l)$
Time to travel between one HRS and electrolyser		12 h
Electricity model data [31,35,36,40,42–44]		
Total electricity demand in Sweden in 2030		159 TWh
Total installed capacity of wind by 2030		21.8 GW
Total installed capacity of solar by 2030		3.6 GW
Average capacity factor for wind		35%
Projected wind energy generation for 2030		66.8 TWh
Capacity factor for solar		11%
Projected electricity generation from solar energy in 2030		3.5 TWh
Total hydropower generation forecasted for 2030		68 TWh
Bio-energy installed capacity		5319 MW
Total number of wind turbines		3882

References

[1] A European Green Deal." [Online]. Available: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en.

[2] How are emissions of greenhouse gases in the EU evolving?" [Online]. Available: https://ec.europa.eu/eurostat/cache/infographs/energy/bloc-4a.html?lang=en.

[3] Greenhouse gas emissions from transport in Europe," European Environment Agency. Accessed: February. 16, 2022. [Online]. Available:https://ec.europa.eu/eurostat/cache/infographs/energy/bloc-4a.html#:~:text=In_202018_2C_20the_20energy_20producing,1990_20to_2024.6_20_25_20in_202018.

[4] World Energy Outlook 2021:386.

[5] C. Brooks, "Germany leads pack of countries pouring finance into hydrogen", [Online]. Available:https://cleanenergynews.ihsmarkit.com/research-analysis/germany-tops-table-of-states-pouring-finance-into-hydrogen.html#:~:text=The_20firm_20looked_20at_20state,and_20planned_20hydrogen_20production_20capacity.

[6] Hydrogen as a fuel for fuel cell electric vehicles." [Online]. Available: https://www.ieafuelcell.com/index.php?id=33.

[7] Cipriani G, et al. Perspective on hydrogen energy carrier and its automotive applications. Int J Hydrogen Energy 2014;39(16):8482–94. https://doi.org/10.1016/j.ijhydene.2014.03.174.

[8] Hydrogen and Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan. pp. 24-54 [Online]. Available: https://www.energy.gov/eere/fuelcells/articles/hydrogen-and-fuel-cell-technologies-office-multi-year-research-development.

[9] Yang C, Ogden J. Determining the lowest-cost hydrogen delivery mode. Int J Hydrogen Energy 2007;32(2):268–86. https://doi.org/10.1016/j.ijhydene.2006.05.009.

[10] Dogliani P, Ruas Rego Canha, Elberry AM, Thakur J. Multi-option analytical modeling of levelized costs across various hydrogen supply chain nodes. Int J Hydrogen Energy 2024;70:737–55. https://doi.org/10.1016/j.ijhydene.2024.05.142.

[11] Reuß M, Grube T, Robinius M, Preuster P, Wasserscheid P, Stolten D. Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Appl Energy Aug. 2017;200:290–302. https://doi.org/10.1016/j.apenergy.2017.05.050.
[12] Schiebahn S, Grube T, Robinius M, Tietze V, Kumar B, Stolten D. Power to gas: technological overview, systems analysis and economic assessment for a case study in Germany. Int J Hydrogen Energy Apr. 2015;40(12):4285–94. https://doi.org/10.1016/j.ijhydene.2015.01.123.
[13] Running on hydrogen thanks to COPERNIC [Online]. Available, https://www.cea.fr/english/Pages/News/Running-on-hydrogen-thanks-to-COPERNIC.aspx; Sep. 2018.
[14] Niaz S, Manzoor T, Pandith AH. Hydrogen storage: materials, methods and perspectives. Renew Sustain Energy Rev 2015;50:457–69. https://doi.org/10.1016/j.rser.2015.05.011.
[15] Dagdougui H. Models, methods and approaches for the planning and design of the future hydrogen supply chain. Int J Hydrogen Energy 2012;37(6):5318–27. https://doi.org/10.1016/j.ijhydene.2011.08.041.
[16] Reuß M, Grube T, Robinius M, Preuster P, Wasserscheid P, Stolten D. Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Appl Energy Aug. 2017;200:290–302. https://doi.org/10.1016/j.apenergy.2017.05.050.
[17] Bolat P, Thiel C. Hydrogen supply chain architecture for bottom-up energy systems models. Part 1: developing pathways. Int J Hydrogen Energy 2014;39(17):8881–97. https://doi.org/10.1016/j.ijhydene.2014.03.176.
[18] Bolat P, Thiel C. Hydrogen supply chain architecture for bottom-up energy systems models. Part 2: techno-economic inputs for hydrogen production pathways. Int J Hydrogen Energy 2014;39(17):8898–925. https://doi.org/10.1016/j.ijhydene.2014.03.170.
[19] Seydel P. Entwicklung und Bewertung einer langfristigen regionalen Strategie zum Aufbau einer Wasserstoffinfrastruktur-auf Basis der Modellverknüpfung eines Geografischen Informationssystems und eines Energiesystemmodells. phdthesis, ETH Zurich; 2008.
[20] Vom Scheidt F, Qu J, Staudt P, Mallapragada D, Weinhardt C. The effects of electricity tariffs on cost-minimal hydrogen supply chains and their impact on electricity prices and redispatch costs. Presented at the Hawaii international conference on system sciences. 2021. https://doi.org/10.24251/HICSS.2021.401.
[21] Reuß M, Grube T, Robinius M, Stolten D. A hydrogen supply chain with spatial resolution: comparative analysis of infrastructure technologies in Germany. Appl Energy Aug. 2019;247:438–53. https://doi.org/10.1016/j.apenergy.2019.04.064.
[22] Glenk G, Reichelstein S. Economics of converting renewable power to hydrogen. Nat Energy Mar. 2019;4(3):216–22. https://doi.org/10.1038/s41560-019-0326-1.
[23] Opportunities for hydrogen energy technologies considering the national energy & climate plans. Fuel Cells and Hydrogen 2 Joint Undertaking 2020:62.
[24] Grube T, Stolten D. The impact of drive cycles and auxiliary power on passenger car fuel economy. Energies Apr. 2018;11(4):1010. https://doi.org/10.3390/en11041010.
[25] Fuel cell heavy duty trucks already in service and providing many CO2 emission-free kilometers [Online]. Available, https://fuelcellsworks.com/news/fuel-cell-heavy-duty-trucks-already-in-service-and-providing-many-co2-emission-free-kilometers/. [Accessed 17 May 2022].
[26] Vehicles kilometres for Swedish road vehicles. Trafikanalys, Sep. 2021;22 [Online]. Available: https://www.scb.se/en/finding-statistics/statistics-by-subject-area/transport-and-communications/road-traffic/vehicles-kilometres-for-swedish-road-vehicles/pong/tables-and-graphs/vehicle-kilometers-2020/. [Accessed 25 February 2022].
[27] Vepsäläinen J, Otto K, Lajunen A, Tammi K. Computationally efficient model for energy demand prediction of electric city bus in varying operating conditions. Energy 2019;169:433–43. https://doi.org/10.1016/j.energy.2018.12.064.
[28] M. I. R. Jacob, “Optimization of infrastructure investment for decarbonization of public buses through electricity and hydrogen,” p. 98. .
[29] Bellini E. Large scale alkaline electrolyzers may be built at €444/kW in 2030 [Online]. Available, https://www.pv-magazine.com/2022/02/09/large-scale-alkaline-electrolyzers-may-be-built-at-e444-kw-in; 2022.
[30] Heavy Truck Driver,” Salary Expert. p. 1 [Online]. Available: https://www.salaryexpert.com/salary/job/heavy-truck-driver/sweden.
[31] Grid Map.” [Online]. Available: https://www.entsoe.eu/data/map/.
[32] J. Egerer, “Data documentation 83 open source electricity model for Germany,” p. 47.
[33] Kießling F, Nefzger P, Kaintzyk U. Freileitungen: planung, berechnung, ausfuhrung. Springer-Verlag; 2011.
[34] Transparency Platform. European network of transmission system operators for electricity [Online]. Available: https://tyndp.entsoe.eu/maps-data. [Accessed 14 May 2021].
[35] Todd F. Renewable energy capacity in Sweden to double to 30GW by 2030. says analyst Jul. 16, 2019. p. 1[Online]. Available: https://www.nsenergybusiness.com/news/renewable-capacity-sweden-2030/. [Accessed 20 May 2022].
[36] Jangö E. “Kraftbalansen på den svenska elmarknaden, rapport 2022,”. 2022.
[37] Energy use in Sweden.” Accessed: May 20, 2022. [Online]. Available: https://sweden.se/climate/sustainability/energy-use-in-sweden.
[38] Renewable power generation costs in 2020 - executive summary”.
[39] Techno-Economic Assumptions — PyPSA-Eur.” Accessed: September. 23, 2024. [Online]. Available: https://pypsa-eur.readthedocs.io/en/latest/costs.html.
[40] System development plan 2022–2031”.
[41] Energy in Sweden – An overview,” Energimyndigheten - Swedish Energy Agency. [Online]. Available: https://energimyndigheten.a-w2m.se/Home.mvc?ResourceId=198022.
[42] Installerad solkraft - svensk solenergi [Online]. Available: https://svensksolenergi.se/statistik/solkraft/. [Accessed 24 September 2024].
[43] Data view.” Accessed: September. 24, 2024. [Online]. Available: https://transparency.entsoe.eu/generation/r2/actualGenerationPerProductionType/show.
[44] Svensk Solenergi - Statistik.” Accessed: May 21, 202AD. [Online]. Available: https://svensksolenergi.se/statistik/solkraft/.