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Grid-supported electrolytic hydrogen production: Cost and climate impact using dynamic emission factors

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ABSTRACT

Hydrogen production based on a combination of intermittent renewables and grid electricity is a promising approach for reducing emissions in hard-to-decarbonise sectors at lower costs. However, for such a configuration to provide climate benefits it is crucial to ensure that the grid electricity consumed in the process is derived from low-carbon sources. This paper examined the use of hourly grid emission factors (EFs) to more accurately determine the short-term climate impact of dynamically operated electrolysers. A model of the interconnected northern European electricity system was developed and used to calculate average grid-mix and marginal EFs for the four bidding zones in Sweden. Operating a 10 MW electrolyser using a combination of onshore wind and grid electricity was found to decrease the levelised cost of hydrogen (LCOH) to 2.40–3.63 €/kgH_2 compared with 4.68 €/kgH_2 for wind-only operation. A trade-off between LCOH and short-term climate impact was revealed as specific marginal emissions could exceed 20 kgCO_2eq/kgH_2 at minimum LCOH. Both an emission-minimising operating strategy and an increased wind-to-electrolyser ratio was found to manage this trade-off by enabling simultaneous cost and emission reductions, lowering the marginal carbon abatement cost (CAC) from 276.8 €/tCO_2eq for wind-only operation to a minimum of 222.7 and 119.3 €/tCO_2eq respectively. Both EF and LCOH variations were also identified between the bidding zones but with no notable impact on the marginal CAC. When using average grid-mix emission factors, the climate impact was low and the CAC could be reduced to 71.3–200.0 €/tCO_2eq. In relation to proposed EU policy it was demonstrated that abiding by hourly renewable temporal matching principles could ensure low marginal emissions at current levels of fossil fuels in the electricity mix.

1. Introduction

In light of recent reports by the Intergovernmental Panel on Climate Change, the task of phasing out fossil energy sources to fulfil the ambitions of the Paris agreement, and accordingly limit global temperature increase to 1.5 °C above pre-industrial levels, appears more urgent than ever before [1]. Hydrogen and hydrogen-based electrofuels could play a significant role in fulfilling this task. The concept of converting electricity into hydrogen through the process of water electrolysis has been touted as a promising technology for reducing emissions in hard-to-abate sectors such as long-haul transport and heavy industry [2,3] and electrolytic hydrogen production has received unprecedented investment and policy support in recent years [4,5].

Although environmental impacts from material use and fabrication processes are not insignificant, the climate impact of electrolytic hydrogen is mainly influenced by the carbon dioxide emitted during generation of the electricity consumed in the process. If driven directly by renewable energy sources, electrolysis of water has been demonstrated to deliver substantial emission reduction potential within a range of sectors, although it is not yet economically competitive compared with its fossil counterparts [3,6]. On the other hand, fully grid-based configurations may offer technical and economic benefits, but at the cost of increased emissions, at least in current power systems [7]. As an alternative, operating electrolysers using directly coupled renewable electricity with the support of the grid, henceforth referred to as grid-supported electrolytic hydrogen production, has become increasingly common in scientific studies and demonstration projects [8–11]. This approach could potentially allow an electrolyser to produce primarily low-emission hydrogen and simultaneously enable a more controllable hydrogen production rate and grid flexibility benefits, while also profiting economically from low-cost grid electricity [9,10,12].

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Nomenclature

Abbreviations

AEF	Average grid-mix emission factor
CAC	Carbon abatement cost
CAPEX	Capital expenditure
CHP	Combined heat and power
CO_2eq	Carbon dioxide equivalent
ECO	Economic optimisation
EF	Emission factor
EMO	Emission optimisation
EU ETS	European Union Emissions Trading Scheme
FLH	Full load hour
GRO	Grid-only operation
H_2	Hydrogen gas
KPI	Key performance indicator
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LR-MEF	Long-run marginal emission factor
MEF	Marginal emission factor
MILP	Mixed-integer linear programming
$OPEX_{fix}$	Fixed operating expenditure
$OPEX_{var}$	Variable operating expenditure
SM	Supplementary material
SMR	Steam methane reforming
SR-MEF	Short-run marginal emission factor
WtE	Wind-to-electrolyser

Symbols

ϵ_i	Post-import–export AEF of country i [gCO_2eq/kWh]
$\epsilon_{internal,i}$	AEF based on internal generation for country i [gCO_2eq/kWh]
$E_{g,t}$	Grid emission factor at hour t [gCO_2eq/kWh]
E_w	Carbon intensity of wind farm [gCO_2eq/kWh]
H	Annual hydrogen production [kg]
$m_{H_2,t}$	Hydrogen production at hour t [kg]
N	Hours in a year
$P_{g,t}$	Electrolyser input from the grid at hour t [MWh]
$P_{import,i,j}$	Electricity imported to country i from each neighbouring country j [MWh]
$P_{internal,i}$	Hourly internal generation for country i [MWh]
$P_{total,i}$	Sum of internal generation and imports for country i [MWh]
$P_{w,t}$	Electrolyser input from the wind farm at hour t [MWh]
r	Discount rate [%]
$ReInv$	Reinvestment cost [€]
Res	Residual value [€]

When considering a grid-connected electrolyser, determination of the carbon intensity of grid electricity is vital to ensure the system represents an efficient mitigation effort [4]. Although a static annual average value is sometimes used to describe grid-related emissions, the complex dynamics of modern power systems, especially those containing a substantial share of intermittent renewables, mean that the generation mix is increasingly volatile, and consequently also the associated emissions. To improve accuracy, generating dynamic emission factors (EFs) with high temporal and spatial resolution has been suggested [13,14]. This can be particularly important for variable loads such as a flexibly operated electrolyser and could serve as a tool for reducing their climate impact through emission-based operation [15]. Dynamic emission factors are commonly defined in the form of either average grid-mix emission factors (AEF) or marginal emission factors (MEF), with the choice of method depending on the characteristics of the electricity consumption analysed. By equally distributing the emissions of all active generation to all electricity consumption, the average grid-mix approach describes the composition of the current generation mix and is typically applied for assigning emissions to already existing demand [13]. This approach has the benefit of simplicity, but the failure to account for certain power system dynamics makes AEFs unsuitable for emissions related to new electricity demand [14,16,17]. Instead, the emissions associated with a change in electricity demand can be described using the marginal approach. In the case of a demand change, all power plants do not respond equally, as would be assumed if AEFs were used. Rather, output variations are provided by the generators currently operating on the margin. The MEF is an estimation of the carbon intensity of the marginal power plants currently in operation [18].

The importance of distinguishing between average grid-mix and marginal EFs has previously been demonstrated in the literature [18]. Fleschutz et al. [13] showed that such a difference could exist in most European countries, while simultaneously illustrating the value of a high temporal resolution for both AEFs and MEFs. During that work, an open-source python package (*elmada*) for estimating AEFs and MEFs in many European countries was developed and made available for use in other studies [19]. The methodology used by Fleschutz and co-workers, aptly named the marginal power plant approach, aims to determine a specific marginal generator at every point in time by modelling the merit order of the electricity system. Despite shortcomings in modelling technical limitations, according to Braeuer et al. [20] it is potentially the most suitable approach for modelling marginal behaviour, although different methods for estimating the MEF can produce drastically different results. Both the present study and previously mentioned literature consider primarily the short-term dispatch of power plants in otherwise static power systems. These short-run MEFs (SR-MEFs) are appropriate when considering the operation of small systems with limited impact of the electricity grid, or in the short term. For estimating the climate impact of new electricity demand in the long term, long-run MEFs (LR-MEFs) have instead been proposed to account for long term changes to the electricity grid [21]. They may, however, be less suitable for describing the emissions associated with the short-term dispatch of a specific flexible load.

As revealed by the considerable difference in grid EFs between different countries demonstrated in [13], electricity system characteristics can greatly influence the climate impact of a grid-connected electrolyser. Due to its low-cost and low-carbon electricity generation, Sweden has been suggested as a promising location for electrolytic hydrogen production. Gigawatt-scale electrolyser targets have been proposed and several large-scale projects within the industry sector have been planned or are already under way, such as the HYBRIT project aiming to produce fossil-free steel by 2025 [22]. Smaller projects in the lower megawatt range are also under consideration [23]. Since electricity demand is expected to increase in parallel, extensive electrolyser deployment presents the challenge of ensuring that power sector emissions remain low [24].

The Swedish generation mix currently consists primarily of hydropower, nuclear, wind and combined heat and power (CHP) [25]. Consequently, annual emissions from Swedish electricity generation are among the lowest in the EU [26]. The country is divided into four national bidding zones, ranging from SE1 in the north to SE4 in the south. There is generally a generation surplus in the northern bidding zones (SE1 and SE2), where most of the hydropower is situated, and a deficit in the southern bidding zones, which are instead predominantly based on nuclear (SE3) and wind (SE4), respectively [25,27]. In addition, SE3 and SE4 maintain oil-based backup plants that are used as a last resort during times of high demand or low generation [28,29].

Today, the Swedish electricity grid is integrated with its neighbours to the extent that it should be considered part of an interconnected northern European system [30]. Although the country is a net exporter on an annual basis [25], previous studies of both Nordic and Swedish systems have demonstrated that a notable amount of electricity-related carbon emissions are emitted outside regional and national borders and applying those borders as system boundaries may thus not accurately reflect system behaviour [26,31,32].

Against this background, several gaps in the literature have been recognised. Although numerous papers have been published on the mitigation potential of electrolytic hydrogen production systems [3,6], few have explored the climate impact of such systems using dynamic emission factors [33,34], especially considering marginal effects [35,36], and none has done so in a Nordic context. In addition, while previous studies have identified both dynamic AEFs and MEFs in a Swedish or interconnected Nordic context [14,31,32], none appears to have done so for the different individual Swedish bidding zones while simultaneously using a marginal power plant approach. Addressing these topics simultaneously can provide additional detail about the short-term climate impact of flexible electrolysis in a region where megawatt-scale hydrogen production is expected to be established in the near future. Finally, since hydrogen produced solely from renewable energy technologies may not accurately represent operation in the partly fossil-based electricity systems of the near future, studies describing the climate impact of grid-supported systems, utilising both directly coupled renewables and the grid, in detail are crucial. Tang et al. [9] investigated the economic potential of renewable hydrogen production in Sweden and proposed a grid-supported layout for minimising the levelised cost of hydrogen, while Raab et al. [10] indicated both technical and economic benefits of equivalent configurations. However, the environmental performance of those systems was not analysed. To our knowledge, studies concerning the climate impact of grid-supported electrolytic hydrogen production systems, and the potential economic and environmental trade-offs they entail, are currently lacking.

The aim of this study was thus to investigate both the cost and climate impact of a dynamically operated grid-supported electrolytic hydrogen production system in the current Swedish electricity system and to evaluate potential economic and environmental trade-offs. To achieve this, the following objectives were defined:

I. Assess hourly average grid-mix and marginal emission factors for Swedish grid electricity through development of an interconnected northern European electricity system model.
II. Evaluate the dynamic techno-economic performance and climate impact of a grid-supported electrolytic hydrogen production system considering the effects of operating strategy, bidding zone and wind-to-electrolyser ratio.

2. Methodology

The system studied was represented by a two-part model where grid-related emissions were initially determined in a northern European electricity system model (Section 2.1), before being used as input to a hydrogen production system (Section 2.2), where the techno-economic performance and climate impact were evaluated (Fig. 1). All simulations considered a full year, with hourly resolution.

The electricity system model was developed based on the open-source python package *elmada* [13,19]. Using historical power system data from 2018 to 2021, *elmada* was used to calculate hourly domestic AEF and MEF values for several European countries. These domestic EFs were then used as input to an electricity import–export model, where re-evaluated AEF and MEF values were determined considering the impact of electricity imports and exports, and transmission limitations between countries and within the Swedish bidding zones.

The hydrogen production system considered consisted of an electrolyser connected to a directly coupled wind farm and to the electricity grid. Electricity, acquired from either source, was used as input to the electrolyser where it was converted to hydrogen following a dispatch schedule determined through an operating strategy. When available, wind energy was the main source of electricity while the grid acted as a complement according to the operating strategy. The grid connection was assumed to be unidirectional, meaning that grid electricity could only be purchased and not sold. No hydrogen usage area or demand profile was assumed and the model could thus be considered strictly supply-driven. Costs were assumed to comprise the acquisition and operation of the electrolyser system, including the cost of electricity, while emissions were assumed to come solely from electricity as

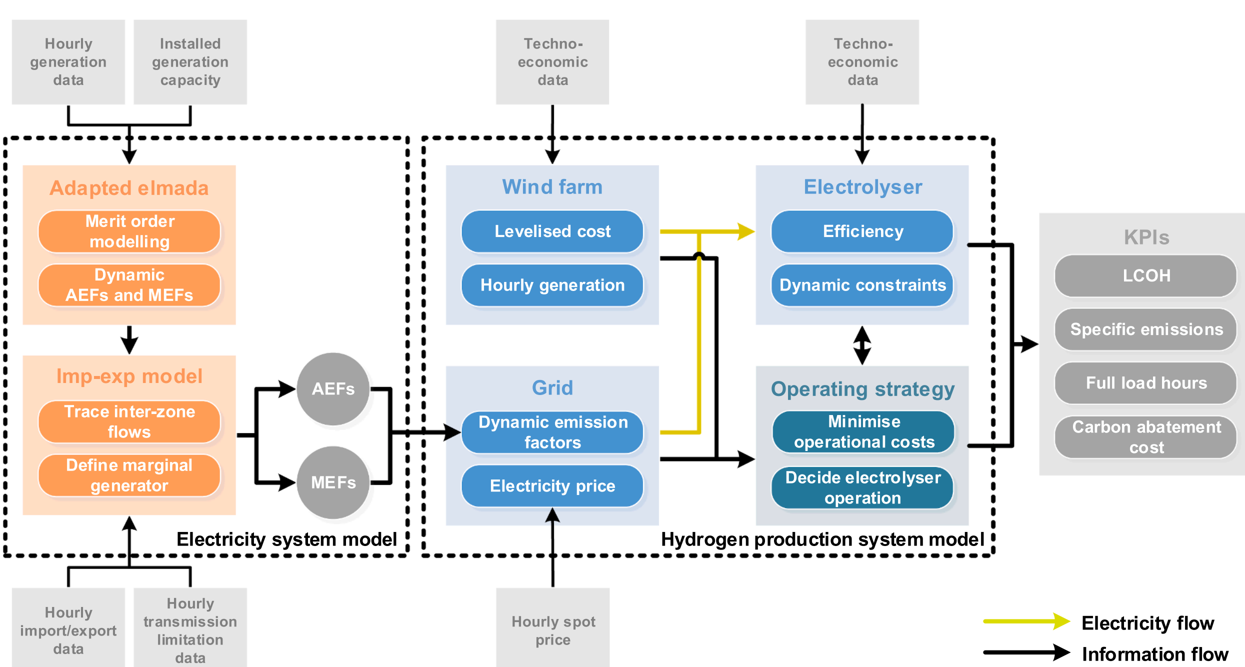

Fig. 1. Schematic overview of the two-part model developed.

manufacturing emissions were not considered. Furthermore, the hydrogen production system was defined as a flexible, low megawatt-scale system deployed in the near future. Its operation was therefore assumed to have negligible impact on the operation and structure of the power system and historical SR-MEF values were deemed appropriate for estimating the climate impact.

The two-part model was applied to a base system configuration (Section 2.3), which was used in a dynamic operation analysis. In addition, the base configuration parameters were varied to investigate the impact of operating strategy (how and when electricity was acquired), bidding zone, and wind-to-electrolyser (WtE) ratio on system performance through key performance indicators (KPIs) described in Section 2.4. The WtE ratio denotes the power capacity of the wind farm in relation to that of the electrolyser.

2.1. Electricity system model

The objective of the electricity system model was to determine both AEF and MEF values on an hourly basis for all four Swedish bidding zones. To achieve this, hourly EFs from all countries included in the analysis (Section 2.1.1) were extracted from *elmada*. Using estimated power plant operating costs together with generation and capacity data [37], *elmada* approximates the merit order for each country to determine the hourly marginal generation technologies, marginal costs and MEFs and AEFs. In this study, the AEFs were based purely on historical generation data, while the MEFs were determined using the merit order as approximated by *elmada*. For *elmada* to be suitable for a system not dominated by conventional thermal power generation and represent the interconnected northern European electricity system more accurately, the original model was modified into an adapted version containing core changes regarding marginal technologies and power generation carbon intensities. All data sets were also updated to include recent years and separate Swedish bidding zones [38]. For a more detailed description of *elmada* and its use in this study, see [13] and Sections S1.1–1.5 in Supplementary Material (SM) to this paper respectively.

In addition, an import–export model was developed where AEF and MEF values from the adapted *elmada* were used together with hourly import and export data between all countries and bidding zones and with hourly transmission limitation data [39–41] to determine post-import–export AEFs and MEFs. The models developed in this study and hourly emission factor time series for all investigated years and countries can be downloaded through SM.

2.1.1. System boundary

To capture the dynamics of an interconnected electricity system, such as that in Sweden, the system boundary must be extended beyond national borders. Thus, the electricity system model developed included not only the four Swedish bidding zones but also adjacent countries (Fig. 2), based on methodology initially proposed by Clauß et al. [32].

The Swedish bidding zones were modelled individually, acting as separate entities with unique hourly emission factors impacted by imports and exports between each other and with neighbouring countries. The neighbouring countries, i.e. the countries with a direct electrical connection to Sweden, were modelled with a high level of detail, defined by having electricity imports and exports affect the AEFs, individually defined marginal power plants and by being subjected to transmission

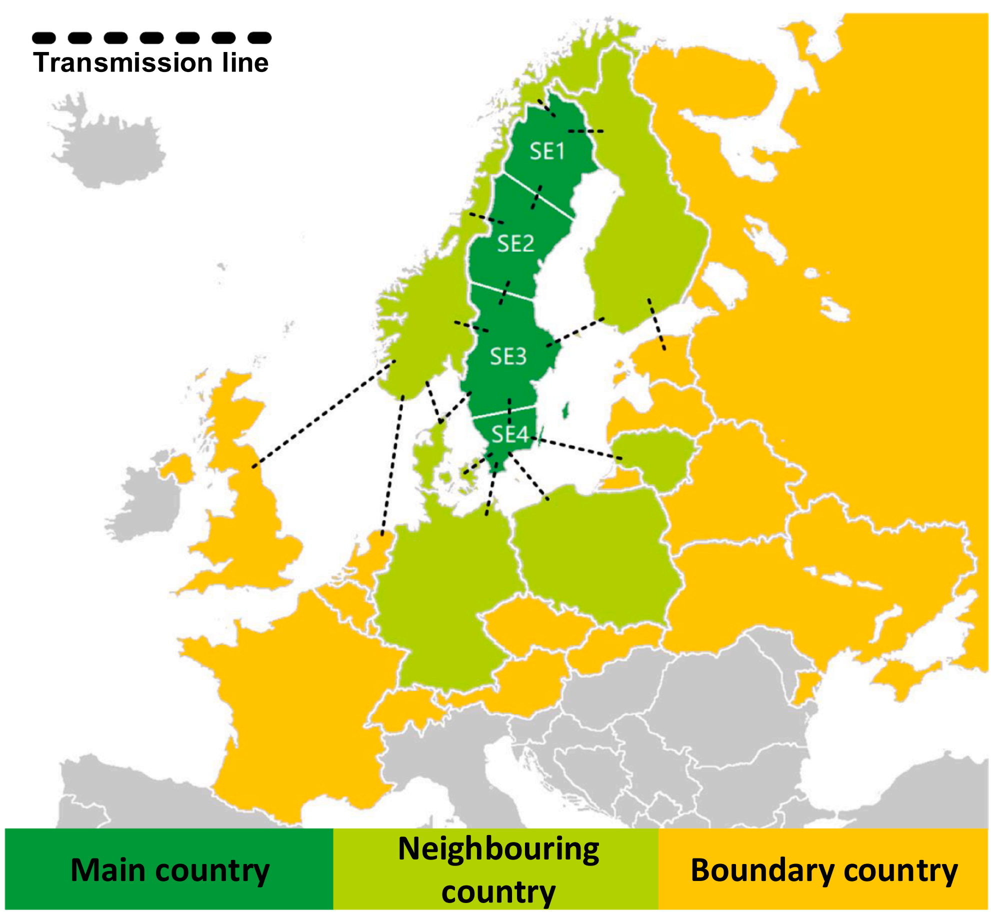

Fig. 2. Map of the countries included in the analysis and the level of detail of which that they were represented in the model. Dotted lines indicate electrical connections between the Swedish bidding zones and neighbouring countries, and important submarine interconnectors.

line limitations. To account for the impact of imports and exports on the neighbouring countries, the system boundary was extended further to include all countries connected to the neighbouring countries (henceforth referred to as 'boundary countries'). The boundary countries were modelled with a lower level of detail, with emission factors based solely on internal generation, making no contribution to marginal generation and thus assumed to be unaffected by transmission limitations. This distinction was made because it was assumed to generate sufficiently accurate AEF values since the impact of imports is diminished due to "mixing" in every country. It is, however, possible for the marginal power plant to be situated in a boundary country, but since the possibility of intra-zone transmission constraints, which were not considered in the model, preventing direct electrical connection between Sweden and the marginal generator also increases with expanded boundaries, marginal generation in boundary countries was omitted for simplicity.

2.1.2. Marginal generation in the Swedish power system

The MEFs were determined by defining the current marginal power plant in the system at every hour of the year. Marginal generation was modelled using the key assumption that only unconstrained load-following plants could be marginal, as argued on several occasions throughout the literature [30,42,43].

In Sweden, load-following in the short term is managed using hydropower. However, water availability in hydropower plants is limited on an annual basis, meaning that an increase in hydropower output at one point in time must be followed by a decrease at another point. A demand increase would not increase the total amount of electricity generated in hydropower plants and hydropower does therefore not provide marginal generation in the slightly longer term [30,43]. Whilst technically capable of flexible operation, nuclear power is conventionally, both in Sweden and globally, used exclusively as base load and does thus not act as marginal generation [44]. CHP plants operate based on heat demand while the output from intermittent renewables such as wind and solar are dependent on weather conditions, limiting their potential participation in the marginal mix. It has been argued, however, that intermittent renewables could be considered as marginal generation during times of renewable curtailment [17,30,42]. A small fleet of gas turbines exists to provide rapid backup generation in case of a large loss of generation, e.g. a nuclear facility malfunction. As these turbines do not respond directly to load changes and are generally not considered part of the power balancing mix, they should also not be considered as a marginal technology in the Swedish system [28,45]. Moreover, as a change in demand may influence the amount of electricity that is imported or exported and in turn impact upon the operation of marginal generators in other countries within the system, the marginal power plant in Sweden could be situated outside the country's borders [14,16]. Altogether, only backup oil-based power plants were considered marginal within Sweden while all unconstrained, load-following power plants in neighbouring countries were considered marginal, similar to what has previously been stated in the literature [16,43].

Unconstrained and load-following power generation was assumed to include non-base load generation such as gas and oil plants which regularly vary their output according to the demand but also conventional base load technologies such as hard coal and lignite power plants which have begun to be operated more flexibly as the proportion of intermittent generation has increased [46]. Two additional unconstrained load-following generation technologies were identified within the neighbouring countries. In Germany, nuclear power plants have also demonstrated load-following capabilities in recent years [47], while both fossil and biomass-based CHP plants have been operated based on wind power fluctuations in Denmark [48]. Since this can be corroborated in the hourly data, both German nuclear power and Danish biomass-based power have been included as marginal technologies. Some additional unconstrained load-following capabilities theoretically exist, such as in German biogas plants [49], but this capacity is relatively small and appears seldom utilized according to the hourly data. It was therefore assumed to have little impact on a national level and was not included in the model. A final exception was made to curtailed wind power, with curtailment assumed to take place during periods of negative electricity prices. An overview of the considered generation technologies can be found in Table 1. A full description of all included carbon intensities and related assumptions can be found in Section S1.7 in SM.

Since the methodological choices described in this section could have a significant impact on the resulting EFs, a description of the assumptions and limitations of the methodology and a discussion on their potential impact on the resulting EF values is provided in Sections S1.5–1.6 in SM.

2.1.3. Import-export model

Post-import–export AEF was defined for all Swedish bidding zones and for all neighbouring countries at every hour as the mixture of both internal generation and imports, using the equation:

$$P_{internal,i} \times \epsilon_{internal,i} + \sum_{j}^{N} P_{import,i,j} \times \epsilon_j = P_{total,i} \times \epsilon_i \tag{1}$$

where:

- $P_{internal,i}$ is the total hourly internal generation for country i
- $\epsilon_{internal,i}$ is the AEF based on internal generation for country i
- $P_{import,i,j}$ is the hourly imports to country i from neighbouring country j
- ϵ_j is the post-import–export AEF of neighbouring country j
- N is the number of neighbouring countries
- $P_{total,i}$ is the hourly sum of internal generation and imports for country i
- ϵ_i is the post-import–export AEF for country i.

This mixture of electricity was then utilised for export to neighbouring countries. By considering Equation (1) for all Swedish bidding zones and for neighbouring countries and rearranging, a linear system of equations was defined. Similar approaches have been developed and used previously for emission factor determination considering electricity imports and exports [26,32]. The system of equations, described in Equation (2), was solved for every hour of the year, providing hourly AEF values for the analysed country and its neighbours:

$$\begin{bmatrix} -P_{total,1} & P_{import,1,2} & \cdots & P_{import,1,N-1} & P_{import,1,N} \\ P_{import,2,1} & -P_{total,2} & \cdots & P_{import,2,N-1} & P_{import,2,N} \\ \cdots & \cdots & \cdots & \cdots & \cdots \\ P_{import,N-1,1} & P_{import,N-1,2} & \cdots & -P_{total,N-1,N-1} & P_{import,N-1,N} \\ P_{import,N,1} & P_{import,N,2} & \cdots & P_{import,N,N-1} & -P_{total,N} \end{bmatrix} \times \begin{bmatrix} \epsilon_1 \\ \epsilon_2 \\ \cdots \\ \epsilon_{N-1} \\ \epsilon_N \end{bmatrix} = \begin{bmatrix} -P_{internal,1} \times \epsilon_{internal,1} \\ -P_{internal,2} \times \epsilon_{internal,2} \\ \cdots \\ -P_{internal,N-1} \times \epsilon_{internal,N-1} \\ -P_{internal,N} \times \epsilon_{internal,N} \end{bmatrix} \tag{2}$$

From the marginal perspective, there would ideally be a single marginal generator, and thus one MEF, for the entire interconnected system. However, technical limitations, such as grid congestion, can influence the source of marginal generation and associated emissions. If the transmission lines connecting a region to the region containing the system marginal generator are operated at maximum capacity, a demand increase in this region would not impact the marginal generator in the system [16,30]. Marginal generation would in this case need to be acquired domestically or from another region.

Table 1
Considered electricity generation technologies including corresponding carbon intensities and assumptions regarding marginal participation.

Technology	Carbon intensities [gCO_2eq/kWh]	Marginal technology	Source
Wind	13.3–20	If price < 0	[50,51]
Solar PV	83–118	No	[50]
Hydro	4.4–51.4	No	[50,52]
Nuclear	4.4–12.9	Germany only	[50,53]
Biomass	46.7–63.7	Denmark only	[50], elmada
Waste	367	No	[54]
Gas (open cycle)	565.5–733.1	Yes	elmada
Gas (combined cycle)	410.5–473.1	Yes	elmada
Lignite	906.1–1257.8	Yes	elmada
Hard coal	826.7–1114.0	Yes	elmada
Oil	783.1–958.9	Yes	elmada

An analysis was conducted, based on an algorithm described in Figure S1 in SM, to determine the country (or bidding zone) that contained the marginal power plant for each bidding zone in Sweden at a certain hour. The algorithm aimed to determine the country with the lowest marginal generation costs subject to conditions in the form of ongoing inter-country electricity exchange and transmission limitations, i.e. a country could only provide marginal generation if it was currently importing from or exporting to Sweden and the transmission capacity allowed for increased electricity transfer. Transmission limitations were only considered within Sweden and between Sweden and its neighbouring countries. Alternative import routes, e.g. importing from Denmark through Norway, were not considered. Two exceptions to this process, representing cases otherwise difficult to include, were considered. Renewable marginal generation was assumed to take place during periods of negative electricity prices, during which wind power was assumed to be curtailed. To account for the fact that the model may fail to accurately determine periods of other technical limitations, the oil-based backup plants in Sweden were assumed to always provide marginal generation to their bidding zone when active, and to all Swedish bidding zones when transmission capacity allowed.

2.2. Hydrogen production system model

The hydrogen production system consisted of four submodels (Fig. 1). An alkaline electrolyser was used to convert electricity to hydrogen, while a wind farm model, based on hourly wind generation and economic data, was used to determine wind energy production costs. In addition, grid electricity could be purchased on the hourly spot market and entailed emissions determined by the electricity system model. Finally, the operating strategy used wind generation and grid data together with electrolyser technical and economic data to determine the lowest achievable levelised cost of hydrogen (LCOH).

2.2.1. Electrolyser model

Since alkaline electrolysis is currently the most mature and affordable electrolyser technology available and its performance in variable conditions is adequate, it was the technology of choice in this study [12]. The electrolyser was modelled using the efficiency of the electrolysis process, with operational constraints in the form of load range and cold start-up time. The operational constraints were implemented within the operating strategy (described in Section 2.2.3). The difference between a hot and a cold start was defined based on a cool-down time. If the electrolyser had been idle for longer than the specified cool-down time, a cold start was required during which the electrolyser consumed electricity without producing hydrogen. This was associated with an electricity cost, corresponding to a start-up cost. Although the suitability of alkaline electrolysis for direct coupling to renewables has previously been questioned due to its rigidity [55], the technology has been proven capable of responding to load changes within seconds and has been deemed suitable for providing frequency regulation [12]. Thus, ramping limitations were assumed to be negligible. The efficiency of the electrolyser stack increases during part-load operation, but this is potentially counteracted by reduced efficiency in auxiliary components, so the electrolyser efficiency was assumed to be constant above the minimum load [56]. A minimum load was also assumed. Since the reported minimum load for alkaline electrolysis varies in the literature a conservative estimation of 20 % was made also considering the impact of auxiliary components on the system load range, corresponding to 2 MW for an assumed 10 MW electricity input capacity system (Table 2).

As most Swedish regions currently lack dedicated gas grids, early hydrogen production systems in the country are likely to involve storage [24]. Accordingly, 24-hour, 200-bar compressed hydrogen storage was included in the economic calculations to account for the impact of gas storage on the system costs. This was assumed to be on the larger end of potential storage capacities for a low megawatt-scale system and thus considered a conservative estimation. The storage was assumed to be discharged at a rate preventing it from limiting the operation of the electrolyser and was thus not considered in the technical model.

2.2.2. Wind farm model

As wind generation varies locally to a great extent even within the Swedish bidding zones, modelling specific wind conditions could not be justified without considering case studies. Instead, wind generation was assumed to represent an average newly constructed Swedish onshore wind farm, characterised by a capacity factor of 36.8 % [67]. Hence, hourly generation data was taken from *renewables.ninja* [68,69] in conditions providing such a capacity factor after considering cut-in and cut-out speeds (Section S2.2 in SM). The same wind data was used for all analyses to simplify the comparative analysis of grid-related emissions and electricity prices.

It was assumed that the electrolyser and the wind farm were under the same ownership and situated at the same site, meaning that renewable electricity could be acquired at production cost and without grid fees. The production cost corresponded to the levelised cost of electricity (LCOE), calculated independently due to the different lifetimes of the wind farm and electrolyser system. The costs and parameters associated with wind power were assumed to equal the average values of new Swedish projects (Table 3). From the given parameters, the LCOE for the average case was calculated according to the principles

Table 2
Techno-economic model parameters for the alkaline electrolyser system. For parameters with a wide range of available values, an estimate was made based on available sources.

Parameter	Value	Unit	Source
Capacity	10	MW[a]	Fixed input
System efficiency	60	$\%_{LHV}$	[4,12]
Load range	20–100	%	[4,12,57,58]
Start-up time (cold)	30	Min	[4,58,59,60]
Start-up cost	Electricity price[b]	€	[60,61]
Shutdown cost	0	€	[60]
Cool-down time	6	hours	[12]
Stack lifetime	9	years	[12,62,63]
System lifetime	25	years	[12,59]
CAPEX	900[c]	€/kW[a]	[2,4,64]
$OPEX_{fix}$	3	% of CAPEX	[12,64,65]
Water cost	~2[d]	€/m^3H_2O	Section S2.1 in SM
Stack replacement cost	35	% of CAPEX	[62–65]
Storage capacity	24	hours	Fixed input
$CAPEX_{storage}$	500	€/kgH_2	[57,63,66]
$OPEX_{storage}$	1.5	% of CAPEX	[57,63,66]
Discount rate	7	%	[64,65]

[a] Rated electrical power input, i.e. W_{el}.
[b] See S2.3 in SM for a description of the start-up cost estimation.
[c] Assumed to include balance of plant, installation and compressor costs for a state-of-the-art 10 MW alkaline system.
[d] The water cost consisted of separate variable and fixed costs and the specific cost therefore varied.

defined in Equation (3), resulting in a value almost exactly in line with the global average in 2021 (€33/MWh assuming 1 USD per €) [70].

2.2.3. Operating strategy

An operating strategy was developed with the purpose of determining the cost-optimal electrolyser operation for every hour of the year for a particular number of full load hours (FLHs) as defined in Equation (6). Different FLH values were used as input to dispatch optimisation, where the time and source of electricity consumption were determined on an hourly basis using a mixed-integer linear programming (MILP) approach, enabling the system to efficiently minimise its operational costs while subject to a range of constraints [71].

The MILP-based dispatch optimisation determined the electrolyser operation for a particular number of FLHs as follows. An objective function containing the costs of grid electricity and start-up related costs was defined, together with constraints limiting the electrolyser load range, start-up process and FLHs. Electricity for hydrogen production could be acquired from the wind farm or the grid, but wind electricity was prioritised, i.e. grid electricity could only be used when the wind could not fulfil the targeted FLHs. For a specific number of FLHs, the MILP optimiser determined the hours with the lowest electricity prices, if wind energy was not enough to fulfil the FLH constraint, and scheduled electrolyser operation thereafter while abiding by technical restrictions. A full mathematical definition of the restrictions is provided in Section S2.3 in SM.

Grid electricity was purchased from the Nord Pool day-ahead market [39]. In addition to this, a grid fee of €8.4/MWh was assumed based on the average for large consumers in recent years (Section S2.4 in SM). Taxes were not included. Despite operating on the day-ahead market, the dispatch strategy was assumed to have infinite foresight, meaning that it considered all hours of the year simultaneously.

Using the electrolyser dispatch suggested by the dispatch optimisation, the variable operating expenditure ($OPEX_{var}$) and annual hydrogen production were calculated. Based on these, the LCOH associated with the particular number of FLHs could be determined according to Equation (3). By investigating a range of FLHs corresponding to a full year (1–8760), the lowest achievable LCOH could also be determined. Note that the FLHs were varied using intervals of 10 to reduce the computational time and that the strategy did not consider any hydrogen demand characteristics.

2.3. System configurations

The system configurations were based on combinations of the following factors:

i. Three operating strategies (economic optimisation of grid electricity, emission-based optimisation of grid electricity, grid electricity only).
ii. Four bidding zones (SE1, SE2, SE3, SE4).
iii. Three WtE power capacity ratios (1:1, 2:1, 5:1).

Table 3
Techno-economic model parameters for the wind farm.

Parameter	Value	Unit	Source
CAPEX	1039[a]	€/kW	[67]
$OPEX_{var}$	0.095[a]	€/kWh	[67]
Residual cost[b]	0.486[a]	€/kW	[67]
Lifetime	27	years	[67]
Capacity factor	36.8	%	[67]
Discount rate	5.2	%	[67]
LCOE	32.4[c]	€/MWh	Calculated

[a] Converted using an exchange rate of 10.5 SEK to 1 €.
[b] Refers to the cost of decommissioning minus the value of remaining parts.
[c] Assumed to apply for all wind farm capacities.

Economic optimisation of grid electricity (ECO) followed the dispatch strategy described in Section 2.2.3, aiming to minimise LCOH. In emission optimisation of grid electricity (EMO), the objective of dispatch optimisation was changed to minimise the MEF of grid electricity instead of the cost. The grid-only strategy (GRO) did not allow for any use of wind power, instead limiting operation exclusively to grid electricity.

A base configuration, serving as a basis for comparison, was defined as follows: a 10 MW electrolyser with a 1:1 WtE ratio, i.e. a 10 MW wind farm, in bidding zone SE2, using the ECO operating strategy. The electrolyser capacity was kept constant at 10 MW in all configurations. SE2 was chosen for the base configuration as it has been proposed as a strategic region for electrolyser deployment in Sweden while offering a combination of low electricity prices and emissions [72]. A detailed analysis using EFs and electricity prices from 2021 is presented in the results & discussion section of this paper while key results for all years (2018–2021) and bidding zones are provided in Tables S2 – S5 in SM.

The handling of excess electricity in systems with WtE ratios above 1:1 was assumed not to affect LCOH. Including electricity sales in the LCOH calculation would not describe the actual production cost of hydrogen. Although useful in certain contexts, allocating income from one part of the system to another complicates the determination of LCOH values [73]. Moreover, choosing between selling electricity or producing hydrogen requires assigning a monetary value to the produced hydrogen as done in [73], which was considered to be beyond the scope of this paper.

2.4. Key performance indicators

To measure the economic performance of the system and allow for comparison with the economic performance of other types of hydrogen production systems, the LCOH was calculated by dividing the sum of all lifetime costs by the lifetime hydrogen production while discounting future years:

$$LCOH = \frac{CAPEX + \sum_{t=1}^{N}\left[\frac{OPEX_{fix}+(OPEX_{var}\times H)}{(1+r)^t}\right] + \sum_{i}^{n}\left[\frac{ReInv_i}{(1+r)^{x_i}}\right] + \frac{Res}{(1+r)^N}}{\sum_{t=1}^{N}\left[\frac{H}{(1+r)^t}\right]} \left[\frac{€}{kgH_2}\right] \tag{3}$$

where:

- $CAPEX$ is the capital expenditure of the system
- $OPEX_{fix}$ is the fixed annual operating expenditure
- $OPEX_{var}$ is the variable annual operating expenditure (grid electricity and water for the electrolyser)
- H is the annual hydrogen production
- r is the discount rate
- $ReInv$ are potential reinvestments taking place in specific years during project lifetime, i.e. stack replacements
- n is the number of reinvestments during project lifetime
- x_i is the year of reinvestment i
- Res is the residual value of the decommissioned project
- N is the system lifetime.

To quantify the emissions from hydrogen produced by the system, the specific emissions of hydrogen (both average grid-mix and marginal) were defined as the carbon dioxide equivalent emissions per kilogram of hydrogen produced:

$$Specific\ emissions = \frac{\sum_t^N (P_{g,t}\times E_{g,t}) + \sum_t^N (P_{w,t}\times E_w)}{\sum_t^N m_{H_2,t}} \left[\frac{kgCO_2eq}{kgH_2}\right] \tag{4}$$

where:

- $P_{g,t}$ is the electrolyser input from the grid at the current hour
- $P_{w,t}$ is the electrolyser input from the wind farm at the current hour

- $E_{g,t}$ is the grid emission factor at the current hour
- E_w is the life cycle carbon intensity of the wind farm
- $m_{H_2,t}$ is the mass-based hydrogen production at the current hour.

The carbon abatement cost (CAC) was determined to estimate the economic potential for climate mitigation provided by the system. Since the CAC can vary depending on the hydrogen application, in this study it was defined compared to state-of-the-art natural gas-based steam methane reforming (SMR) without carbon capture and storage, i.e. the difference in cost between system and fossil hydrogen production divided with the specific emission difference between system and fossil hydrogen production as per Equation (5):

$$CAC = \frac{LCOH_{system} - LCOH_{fossil}}{Specific\ emissions_{fossil} - Specific\ emissions_{system}}\left[\frac{€}{tCO_2eq}\right] \quad (5)$$

where:

- $LCOH_{system}$ is the levelised cost of electrolytic hydrogen
- $LCOH_{fossil}$ is the levelised cost of natural gas-based hydrogen, assumed to be 1.6 €/kgH_2 in Europe in 2018 [2]
- $Specific\ emissions_{system}$ are the specific emissions of the investigated hydrogen production system
- $Specific\ emissions_{fossil}$ are the are the specific emissions of natural gas-based hydrogen, assumed to be 12 kgCO_2eq/kgH_2 [74,75].

Finally, the utilisation of the system was quantified using the full load hours. The system FLHs were based on the electrolyser input energy and defined individually for wind and grid electricity as defined in Equation (6).

$$FLHs = \frac{Annual\ electricity\ consumption\ [MWh]}{Rated\ capacity\ [MW]} \quad (6)$$

3. Results and discussion

The AEFs and MEFs resulting from electricity system model simulations for the years 2018 to 2021 are presented in Section 3.1 together with an analysis of the characteristics of the Swedish electricity system. They were then applied in techno-economic and environmental performance analysis of the hydrogen production system in Section 3.2. Based on the results, the potential of grid-supported electrolytic hydrogen production and dynamic EFs in Sweden, and related policy implications, were assessed in Sections 3.3–3.5.

3.1. Dynamic emission factors in Sweden

3.1.1. Average grid-mix emission factors

The majority of hourly AEF values observed lay between 10 and 60 gCO_2eq/kWh, making them comparable to those achieved for Sweden in previous studies [26,31], with higher median values the farther south the bidding zone was located. The range of values in the distributions also differed the between bidding zones, with high peak values observed in zones SE1 and SE4. The AEF distributions for all Swedish bidding zones are presented in Fig. 3. AEF distributions including all neighbouring countries are shown in Figure S2 in SM.

To some extent, the AEF distributions can be explained by considering the generation mix of each zone. The southern zones contained more significant shares of CHP and backup thermal power plants, leading to higher emissions at times of peak electricity and heating demand. However, the temporal variations, i.e. the annual distribution ranges, are better understood by also considering the impact of imports and exports on the different bidding zones. A wider distribution of AEF values correlated with the share of non-Swedish imports. For example, the high peak AEF values in SE1 were caused by short periods of large-scale import from Finland at times when the Finnish electricity mix constituted a large share of fossil generation. Likewise, SE4's direct

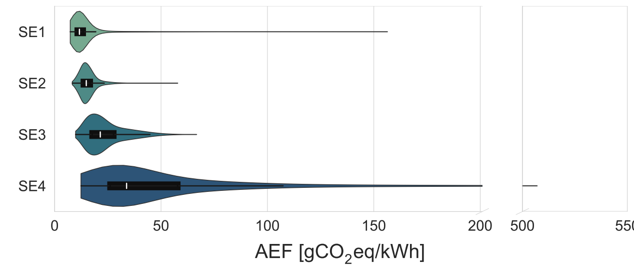

Fig. 3. Violin plot of hourly average grid-mix emission factors (AEF) distributions for each of the four Swedish bidding zones (SE1-SE4) in the period 2018–2021. The box ranges from the lower to the upper data quartile while the whiskers extend further by 1.5 times the interquartile range. The white line indicates the median value. The coloured area shows a smoothed probability density of the data.

connection to several countries with a largely fossil-based generation mix, such as Poland and Germany, meant that periods of fossil imports, and consequently higher AEFs, were more frequent. A sample of AEFs both with and without consideration of imports and exports for SE4 can be found in Fig. 4, further highlighting the impact of inter-country trading. In that diagram, the emission-reducing effects of imports from SE3 and emission-increasing effects of inter-country imports can be observed. The annual share of non-Swedish imports for each bidding zone is presented in full in Table S1 in SM and the methodology is defined in Section S1.8 in SM.

Seasonal trends of lower AEFs in summer compared with winter months were also observed (Figure S4 in SM). Although small, these differences were accentuated in zones SE3 and SE4, potentially due to the increased influence of CHP and thermal backup plants during the winter months in the southern bidding zones. Considering diurnal values instead (Figure S5 in SM) showed that the AEFs were generally lower during peak load hours in morning and evening, possibly as a consequence of increased hydropower utilisation induced by higher electricity demand. A reduction in AEFs took place in later years of the study period (Figure S3 in SM), caused by fuel switches in CHP units, where fossil fuels were replaced by biofuels [76], and by high EU Emission Trading System (ETS) prices, which shifted fossil generation to more efficient gas plants.

3.1.2. Marginal emission factors

The hourly MEF values (Fig. 5) were notably higher than the AEFs. Although MEF values around 500 gCO_2eq/kWh were slightly more common in the northern bidding zones, the spatial trends observed in the AEF case were not as apparent for the MEFs as the distributions in all bidding zones were similarly shaped. Meanwhile, even though the MEF distributions had a wider range of values compared with the AEFs, the majority of MEF values were concentrated around the median value of approximately 900 gCO_2eq/kWh. Seasonal and diurnal distributions (Figures S6 and S7 in SM) failed to reveal clear tendencies similar to those seen for the AEFs. A potential decrease during peak load hours was however observed in accordance with the merit order dilemma as described by Fleschutz et al. [13]. Additionally, annual distributions suggested that the spatial differences increased slightly in recent years (Figure S8 in SM).

The high MEF values were an expected consequence of assuming that marginal generation consisted primarily of dispatchable fossil generation in an otherwise low-carbon system, a pattern also recognised by Sjödin and Grönkvist [16] and observable in [13], albeit due to methodological differences higher than previously determined in the literature. In [14], average hourly Swedish MEFs considering imports and exports were around 600 gCO_2eq/kWh, at least partially lower because of the inclusion of Swedish CHP in the marginal mix. Furthermore, in [31] the MEFs were defined based on a marginal mix consisting of all generation technologies, leading to significantly lower values.

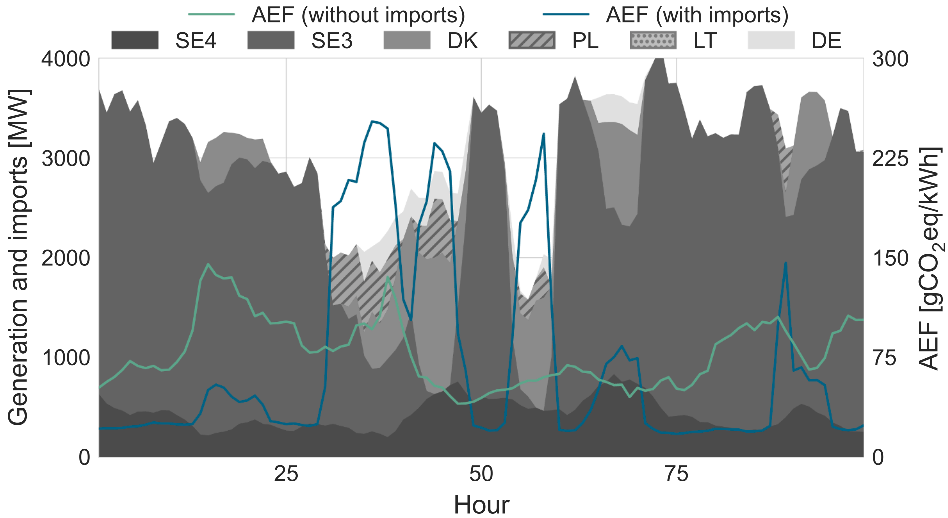

Fig. 4. A 100-hour sample of the origin of electricity generation in Swedish bidding zone SE4 in 2021 (grey, left axis, stacked areas) and its impact on the hourly average grid-mix emission factor (AEF) variation (teal and green, right axis, lines). DK: Denmark, PL: Poland, LT: Lithuania, DE: Germany.

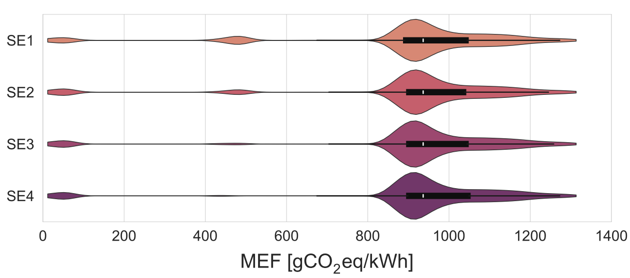

Fig. 5. Violin plot of hourly marginal emission factor (MEF) distributions for each Swedish bidding zone (SE1-SE4) in the period 2018–2021. The box ranges from the lower to the upper data quartile while the whiskers extend further by 1.5 times the interquartile range. The white line indicates the median value. The coloured area shows a smoothed probability density of the data.

The characteristics of the MEFs were examined in greater detail to provide a more extensive description of the marginal generation. In Figure S9 in SM, the country of origin and generation technology of the marginal generator are shown for all bidding zones and years. Marginal electricity in Sweden originated predominantly from Denmark and Germany and was generated using coal and lignite power plants. This explains the high frequency of MEF values around 900 gCO_2eq/kWh in Fig. 5. German nuclear power accounted for approximately 5 % of marginal generation in 2019, but its contribution was otherwise insignificant since its early placement in the merit order meant that is was only ramped down during periods of very low demand or high renewable penetration. Renewable curtailment through negative electricity prices was also a rare occurrence, taking place a maximum of 12 h per year in 2021. The majority of low-carbon MEF values was instead provided by Danish biomass in 2021, a consequence of high EU ETS prices reducing its operating costs compared to the fossil alternatives. Overall, low-emission MEF values were relatively infrequent, with values below 100 gCO_2eq/kWh accounting for 6 % of MEF values across all years and bidding zones, reaching up to 18 % in 2021. Although the origin and generation technology of the MEFs varied both spatially and temporally to a greater extent than can be discerned in Fig. 5 due to transmission limitations between both bidding zones and countries, the impact of this on the actual MEF values was minor. Essentially, country or even technology changes did not necessarily elicit noteworthy emission variations. Transmission limitations nonetheless helped explain the slight increase in MEF values around 500 gCO_2eq/kWh observed in the northern bidding zones, where grid congestion prevented cheaper generation from the southern neighbours from providing marginal generation in the north (SE1 and SE2). This increased Norwegian and Finnish marginal contributions, constituting a larger share of gas-based power plants and, amplified by the high EU ETS prices in 2021, increased gas-based marginal generation in Sweden, producing a higher frequency of lower emission MEFs.

3.1.3. *Different perspectives on marginal emissions*

It is important to bear in mind that the MEF values determined in this study can only describe the short-term implications of additional electricity consumption, which affects how any results based on these EFs should be interpreted. For example, the size and characteristics of an additional load could potentially impact the choice between emission factors. A large, permanent, demand increase may not have a major impact on marginal electricity generation, but rather upon the construction of new power plants [77]. The carbon intensity of new demand could then, at least in the initial phases, be estimated by the emissions associated with planned power plant construction in the system, the build margin [18]. Archsmith et al. [78] claimed that the future impacts of a large-scale demand increase can also not be considered marginal, and instead advocated the use of AEFs for this purpose.

Moreover, Hawkes [21] proposed that certain measures dynamically interact with the grid, implicitly causing structural changes to the system, and introduced the LR-MEF. In contrast to the SR-MEF used in this study, LR-MEF considers the long-term climate impact of new electricity demand through both the commissioning and decommissioning of new power plants based on the characteristics of the new load as well as the resulting impact on system operation. Such an approach can potentially predict the installation and operation of new renewable energy caused by long-term demand changes and consequently produce lower MEF values, as recently demonstrated in a study by Gagnon and Cole [79]. Nevertheless, dynamic LR-MEF studies require demanding modelling and assumptions of power system evolution while maintaining high temporal resolution. To our knowledge, such studies are currently restricted to isolated, non-interconnected, power systems and longer or limited time intervals, reducing the spatial and temporal accuracy explored in the present study. The consequences of using SR-MEFs and how other perspectives may influence the climate impact of hydrogen production in Sweden are discussed further in Section 3.4.

The use of historical SR-MEF values may also have influenced the emissions seeing as this approach does not account for the fact that the dispatch of additional load could lead to the dispatch of additional power plants and alter the MEFs. This was overlooked, as described in Section 2, due to the relatively small electrolyser capacity compared to the power plant capacities rendering such a scenario implausible.

In addition, hydropower could influence marginal generation by temporally shifting the dispatch of thermal generators despite not being included in marginal generation mix directly [42]. Short-term approximation of MEFs in a hydropower-based system may thus be redundant. However, any future generation increase due to hydropower balancing is likely to be of the same type as the generation initially shifted, since the presumed value of stored water would be expected to be similar during the time of output increase and decrease, at least in the absence of transmission limitations [30]. For a more thorough discussion on the validity of the MEFs determined in this paper, see Section S1.6 in SM.

3.2. Analysis of hydrogen production system

3.2.1. Impact of operating strategy

Fig. 6 depicts the relationship between LCOH and specific emissions for varying FLHs using the three operating strategies defined in Section 2.4. Wind-only operation was possible up until 2980 FLHs, slightly less than produced by the wind farm due to the flexibility restrictions described in Section 2.2.3. This corresponded to a LCOH of 4.68 €/kgH_2 and a CAC of 276.8 €/tCO_2eq in both average grid-mix and marginal cases. This is in line with the lower end values for wind-based electrolysis presented in [74]. However, large ranges in the literature regarding both emissions and costs of SMR mean that the CAC vary significantly depending on assumed values. Utilising grid electricity to increase the FLHs beyond those provided by wind power indeed decreased the LCOH regardless of strategy. However, using grid electricity to increase the FLHs could only reduce the LCOH to a certain degree, after which increasing electricity prices made further utilisation less profitable. A breakdown of the costs associated with the base configuration and their respective contribution to the LCOH for varying FLHs can be found in Figure S10 in SM.

A combination of wind and grid electricity appeared to be capable of further reducing LCOH compared with exclusively utilising grid electricity. The lowest LCOH, 3.19 €/kgH_2, was achieved using the ECO strategy at 6950 FLHs as described in Section 3.2.1, corresponding to a 32 % cost reduction compared with maximum wind-only operation and a 9 % reduction compared with the lowest achievable LCOH by the grid-only (GRO) system (3.51 €/kgH_2). The EMO strategy reduced costs compared with exclusively using wind, but less than the ECO strategy, reaching a minimum LCOH of 3.41 €/kgH_2. Since the GRO strategy had to operate solely using grid prices, it exhibited higher LCOH values at high FLHs as it was forced to purchase also during high-price periods that could be avoided by the combined wind-grid strategies.

Use of grid electricity also introduced changes to both average grid-mix and marginal emissions. At low utilisation rates (fewer than 2980 FLHs), only wind energy was required in ECO and EMO strategies and both average grid-mix and marginal emissions were low (around 0.9 kgCO_2eq/kgH_2). At the minimum LCOH, the associated specific marginal emissions were around 22 kgCO_2eq/kgH_2 in the ECO case and more than 40 kgCO_2eq/kgH_2 in the GRO case, exceeding those of fossil hydrogen production using SMR (assumed to be 12 kgCO_2eq/kgH_2). This trade-off between LCOH and emissions was quantified using the lowest achievable average grid-mix and marginal CAC in Fig. 7(a). A minimum marginal CAC of 268.9 €/tCO_2eq was achieved at 3100 FLHs using the ECO strategy, a slight decrease compared to wind-only operation (3 %). This was possible in part due to the assumed renewable curtailment taking place at negative electricity prices but also because the initial grid purchases consisted primarily of small amounts allowing the electrolyser to continue operation when the wind farm produced slightly below the minimum electrolyser load of 2 MW, meaning that many of these initial FLHs increases were primarily supplied through previously not utilised wind power (see Section 3.2.4). The large increase in marginal emissions occurring beyond 3100 FLHs could be avoided to some extent by purchasing grid electricity based on minimising the MEF values rather than the electricity price, i.e. the EMO strategy. Using this strategy, the low MEF values identified in Fig. 5 were utilised and the FLHs could be increased with around 1200 h at only a slight increase in specific MEF emissions. The lowest achievable marginal CAC was 222.7 €/tCO_2eq at 4180 FLHs, a 20 % reduction compared to wind-only operation. From an AEF perspective, the overall low-carbon characteristics of the grid made the difference between strategies negligible and the reduced LCOH thus led to a lowest AEF-based CAC of 142.6 €/tCO_2eq at the point of minimum LCOH using the ECO strategy.

3.2.2. Impact of bidding zone

The impact of bidding zone on the LCOH and specific emissions is shown in Fig. 8. Due to lower electricity prices, lower LCOH was observed in the northern bidding zones compared with the southern. Minimum LCOH values of 3.19 €/kgH_2 in both SE1 and SE2 (6980 and 6950 FLHs) and 3.43 and 3.63 €/kgH_2 in SE3 and SE4 respectively (6240 and 5540 FLHs) were achieved.

From an emissions perspective, both specific average grid-mix and marginal emissions increased more gradually in the northern zones. This was primarily a consequence of a higher share of efficient gas power plants in the marginal mix in the north and more imports and CHP in the average mix in the south, as explained in Section 3.1. Thus, there were

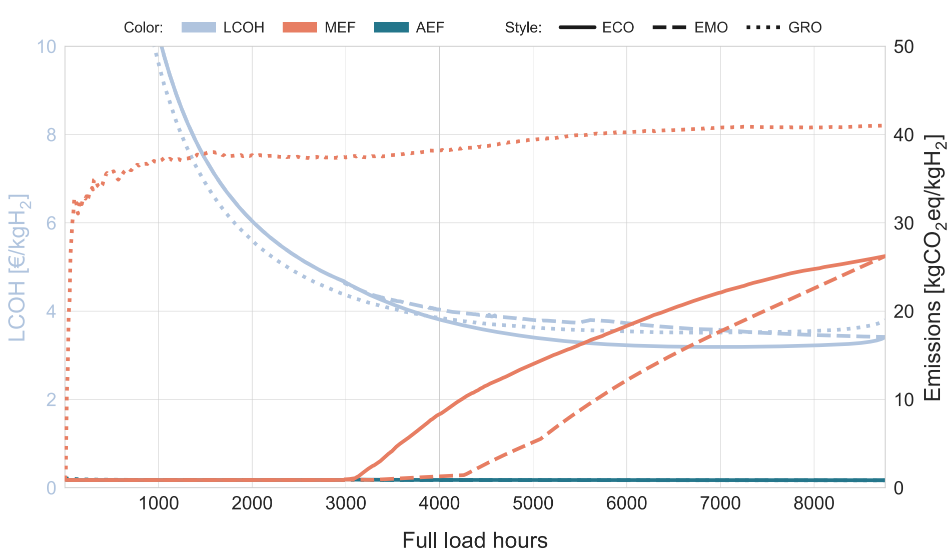

Fig. 6. Levelised cost of hydrogen (LCOH; light blue, left axis) and specific average grid-mix (AEF; teal, right axis) and marginal (MEF; orange, right axis) emissions from hydrogen production for varying full load hours (FLHs) for ECO (economic optimisation; solid line), EMO (emission optimisation; dashed line) and GRO (grid-only; dotted line) operating strategies in Swedish bidding zone SE2 during 2021 with a 1:1 WtE ratio. Note that up to 2980 FLHs, the ECO and EMO strategies were both based solely on wind power and are thus identical.

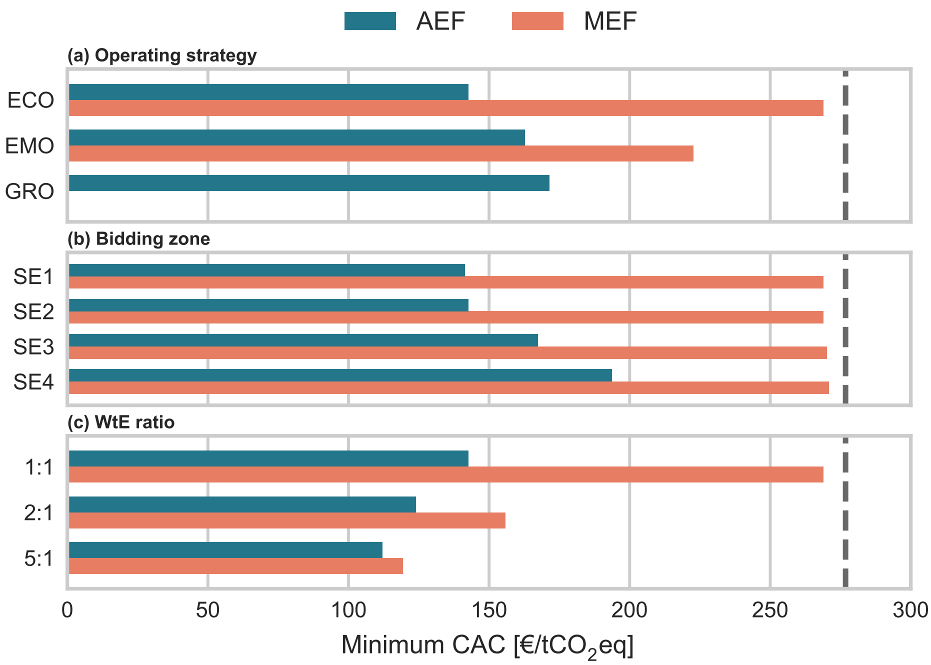

Fig. 7. Minimum average grid-mix (teal) and marginal (orange) carbon abatement cost (CAC) for grid-supported hydrogen production compared to natural gas-based steam methane reforming for the investigated (a) operating strategies, (b) bidding zones and (c) wind-to-electrolyzer (WtE) ratios. The vertical lines indicate both average grid-mix and marginal CAC from wind-only operation with a 1:1 WtE ratio. Note that consistently high marginal emissions meant that there was no marginal CAC using the GRO strategy.

both economic and environmental benefits to hydrogen production in SE1 and SE2 compared to SE3 and SE4. However, marginal emissions still increased drastically from grid operation in all bidding zones and the minimum marginal CAC was again achieved using mostly wind-only operation at 3070–3100 FLHs (268.9–270.9 €/tCO_2eq). The difference in LCOH and AEF values led to varying minimum AEF-based CAC values between 141.4 and 193.7 €/tCO_2eq with lower values in SE1 and SE2 (Fig. 7(b)).

3.2.3. *Impact of wind-to-electrolyser ratio*

A larger wind farm enabled more hydrogen production from wind energy and in turn provided environmental and potentially economic benefits, as can be observed in Fig. 9. It had a positive impact on LCOH, decreasing the lowest achievable value from 3.19 €/kgH_2 in the base configuration (1:1 WtE ratio) to 2.98 €/kgH_2 with a 2:1 WtE ratio and to 2.85 €/kgH_2 with a 5:1 WtE ratio (at 7460 and 8180 FLHs respectively) since more hydrogen could be produced at the same cost. Undeniably, a considerable amount of the electricity generated by the larger WtE ratio systems was not utilised for hydrogen production and the economic feasibility of such a layout is thus determined by the value of this excess electricity on the electricity market. Expanding the system boundaries and including both the total cost of the wind farms and sale of excess electricity in the LCOH calculation increased LCOH by 2 % to 3.05 €/kgH_2 with a 2:1 WtE ratio and decreased it by 39 % to 1.73 €/kgH_2 with a 5:1 WtE ratio at the same FLHs. Full optimisation of such a system requires further analysis beyond the scope of this study, but a larger wind farm appears to have potential to reduce the total system costs.

For AEFs, no significant differences were observed between wind capacities due to the low-carbon characteristics of the grid in SE2. However, more wind-based hydrogen production drastically reduced the specific marginal emissions at high FLHs. In the 5:1 WtE system, hydrogen production exclusively based on wind power could be achieved at up to 7500 FLHs compared to 2980 in the 1:1 WtE ratio system and consequently generate larger quantities low marginal emission hydrogen and reduce the minimum marginal CAC by 57 % compared to wind-only operation to 119.3 €/tCO_2eq (Fig. 7(c)). Additional

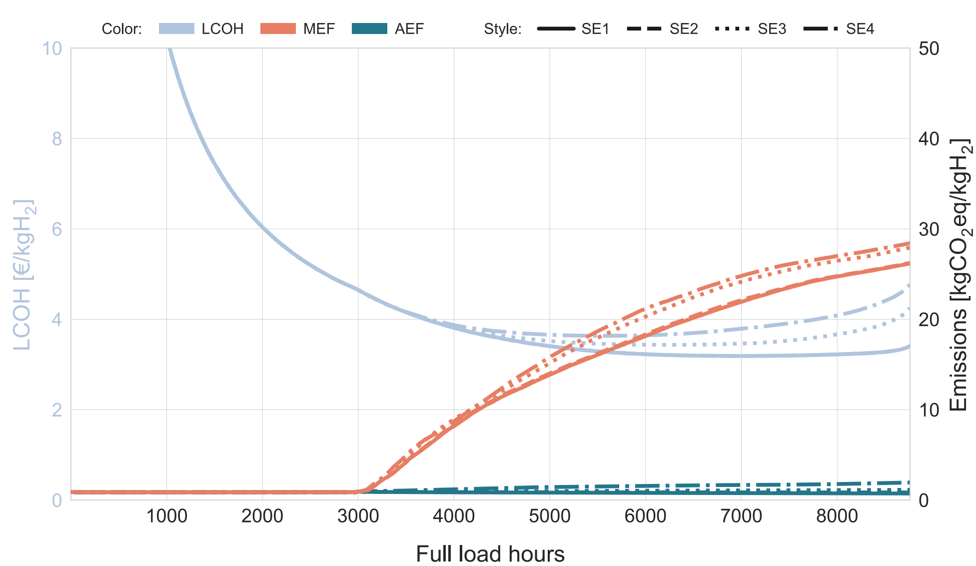

Fig. 8. Levelised cost of hydrogen (LCOH; light blue, left axis) and specific average grid-mix (AEF; teal, right axis) and marginal (MEF; orange, right axis) emissions from hydrogen production for varying full load hours (FLHs) in Swedish bidding zones SE1 (solid line), SE2 (dashed line), SE3 (dotted line) and SE4 (dashed and dotted line) in 2021 using the ECO (economic optimisation) operating strategy with a 1:1 WtE ratio. Note that up to 2980 FLHs, operation was based solely on spatially constant wind power and performance in all bidding zones was thus identical.

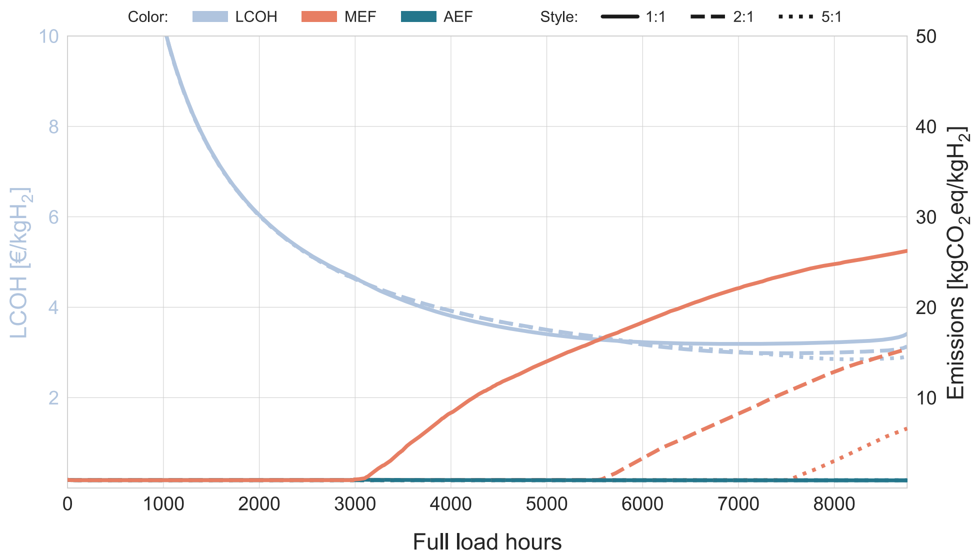

Fig. 9. Levelised cost of hydrogen (LCOH; light blue, left axis) and specific average grid-mix (AEF; teal, right axis) and marginal (MEF; orange, right axis) emissions from hydrogen production for varying full load hours (FLHs) for 1:1 (solid line), 2:1 (dashed line) and 5:1 (dotted line) wind-to electrolyser ratios in Swedish bidding zone SE2 during 2021 using the ECO (economic optimisation) operating strategy.

improvements could likely be achieved by combining a larger wind farm with the EMO strategy analysed in Section 3.2.2.

Since both hydrogen and electricity demand in Sweden are set to increase, it may prove beneficial to tackle both issues simultaneously, especially as the urgency of climate change necessitates emission reductions from hard-to-decarbonise sectors in parallel with electricity generation. The results obtained in this study indicate that complementing new wind farms with lower capacity electrolysers can allow for production of low-carbon hydrogen at competitive prices. Such a set-up could also increase the operational flexibility of the wind farm, and therefore still provide grid benefits, and allow for oversizing renewables compared with grid capacity. For instance, Korpås and Greiner [80] demonstrated that electrolytic hydrogen production adjacent to wind farms could increase the penetration of wind power in weak grids. Furthermore, McDonagh et al. [73] showed that adding an electrolyser system to an offshore wind farm could be economically feasible and might even improve the economic performance of the wind farm in scenarios of high hydrogen values and avoided curtailment, while Martínez-Gordón et al. [81] indicated that hydrogen production could decrease the system cost of a large offshore wind grid in the North Sea.

3.2.4. Analysis of dynamic electrolyser operation

An example of the influence of the operating strategy on electrolyser dispatch is presented in Fig. 10. Minimising the operating costs while targeting a certain number of FLHs in practice led to a maximum purchasing price. The more FLHs targeted, the higher the grid purchase price. Below this price, the electrolyser was operated at maximum capacity and above this price it operated based on wind generation. In Fig. 10, the maximum purchasing price was approximately 35 €/MWh, below which the electrolyser was observed to operate at maximum capacity, as seen between hours 110 and 125.

Fig. 10 also demonstrates how technical restrictions in electrolyser performance, such as the load range and start-up time, affected operation. Grid electricity could be used to avoid electrolyser shutdown when wind output was lower than the electrolyser minimum load of 2 MW. The economic feasibility of this depended on the electricity price and

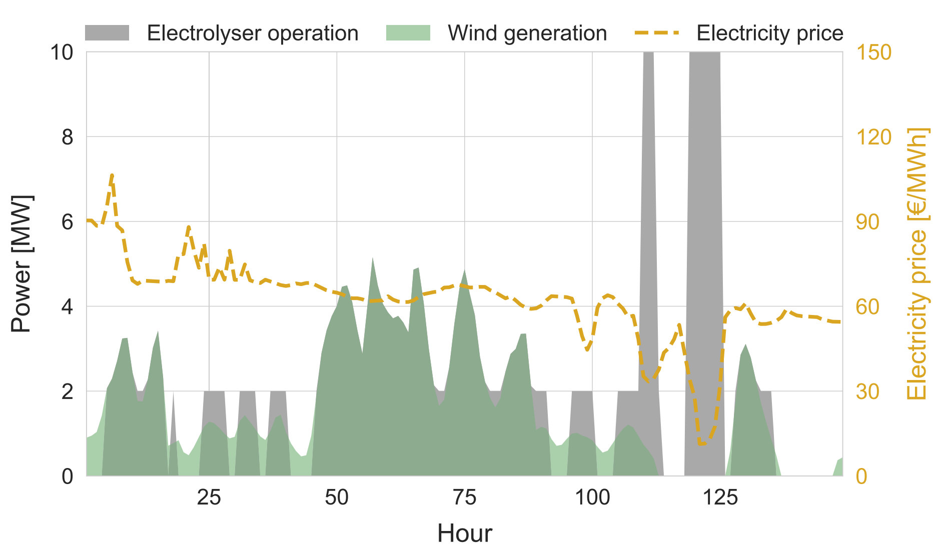

Fig. 10. A 150-hour sample of electrolyser operation for the base configuration while targeting 5000 full load hours (FLHs). Electrolyser operation (grey) extending beyond the wind-based electrolyser operation (dark green) was conducted using grid electricity, while wind generation not coinciding with electrolyser operation (light green) was not utilised for hydrogen production.

wind output, as can be observed around hours 25–40. Implications of such small-scale grid purchases are also apparent in Figs. 6 and 8, where only a slight increase in MEF-based emissions was seen during the initial hours of grid operation as otherwise wasted wind energy could be utilised together with grid electricity. In addition, operational costs could be minimised by purchasing high-cost electricity to avoid longer periods of downtime and subsequent cold starts and production losses, which was the reason behind the single hour of electrolyser operation during hour 20.

3.3. Summary of full dataset results

The results in Section 3.2 demonstrated that a reduction in hydrogen production costs in Sweden could potentially be achieved by combining direct coupling of renewables with grid electricity. Although not yet competitive with its conventional fossil-based counterpart at an assumed production cost of 1.6 €/kgH_2 in 2019 [2], electrolytic hydrogen production from grid-supported electrolyser systems could potentially prove to be possible at levelised costs around 3 €/kgH_2. This is in line with the lowest LCOH values for such systems obtained by Raab et al. [10] and somewhat below those estimated for Sweden specifically by Tang et al. [9]. Furthermore, upon studying system performance across all years and bidding zones (Tables S2 – S5 in SM), it can be concluded that the extent of the LCOH reduction achieved from the utilisation of grid electricity will be affected by the electricity price, as the minimum LCOH of a 1:1 WtE ratio system using the ECO strategy varied between 2.40 and 3.63 €/kgH_2. Compared with the corresponding minimum LCOH achieved using wind-only operation with a 1:1 WtE ratio, this represented cost reductions of 49 % and 22 % respectively. The GRO strategy proved more expensive than the ECO strategy in all years except 2020, when grid prices were exceptionally low, highlighting the potential economic advantage of combined wind-grid systems. The lower prevalence of low-carbon MEF values reduced the potential marginal CAC decrease using the EMO operating strategy in earlier years as the minimum marginal CAC varied between 222.7 and 255.8 €/tCO_2eq across all investigated years and bidding zones. This corresponded to a 6–17 % reduction compared to the ECO strategy, using which values between 268.9 and 272.2 €/tCO_2eq were achieved, and an overall 8–20 % reduction compared to wind-only operation. No notable annual and spatial differences were found for the WtE ratios, since the same wind data was used for all years and bidding zones. AEF-based CAC values varied between 71.3 and 200.0 €/tCO_2eq throughout all years and bidding zones for the base configuration, highlighting a variation in AEFs but in particular a variation in electricity prices.

3.4. Uncertainties and sensitivity analysis

As alkaline electrolysis technology is still rapidly developing, both technical and economic parameters vary between sources and publication years. With costs expected to decrease in the near future, especially for multi-stack applications and large production volumes, the uncertainty is further increased [12]. The cost of grid connection may also slightly increase the LCOH for all grid-connected systems. This cost could be particularly significant in offshore contexts [70]. In addition, natural gas and EU ETS prices have drastically increased during late 2021 and 2022. To study the effects of this, natural gas and EU ETS prices were varied in a sensitivity analysis using values seen during the first six months of 2022. The resulting fossil hydrogen production costs from SMR were shown to reach up to 8 €/kgH_2, making FLHs above approximately 1500 economically feasible for the investigated system. The impact of recent electricity prices was also investigated. Electricity prices from the first six months of 2022, perhaps surprisingly, reduced the LCOH of the base configuration in both northern and southern bidding zones as a consequence of more low-price hours despite the overall price hike. Grid-supported renewable electrolyser systems thus appeared to be more competitive in the first half of 2022. The assumptions and calculations used for these analyses can be found in Sections S3.1–3.2 in SM.

An important trade-off between cost and climate impact emerged, as the largest economic benefits of grid electricity entailed extensive carbon emissions from a marginal perspective. In contrast, from the average grid-mix perspective, grid electricity could be said to improve the overall system performance. Due to the difference in climate impact depending on the choice of EF, it is important to remember the context within which the EFs can be applied, as discussed in Section 3.1.3. For a single facility or early adopters, the emissions may initially be described reasonably well using the SR-MEF determined in this study [21]. However, if a large fleet of electrolysers is deployed in the long term, the average grid-mix or build margin may also be appropriate for analysing the climate impact of new hydrogen production. Assuming the build margin to constitute solely renewable energy technologies, both approaches suggest a smaller climate impact of the investigated system in contrast to the short-term marginal perspective. Accounting for long-term changes in marginal electricity generation caused by the implementation of electrolysers, described using LR-MEFs, would likely lead to the integration and operation of additional renewable energy in the grid and strengthen the environmental case for hydrogen production even in smaller scales. Hence, a potential trade-off between short-term emission increases and long-term emission reductions may arise with a rapid increase in on-grid hydrogen production with fossil marginal generation in the near future being offset by additional renewable generation in the long run.

Different assumptions regarding what constitutes SR-MEFs can also significantly affect the results in the short term. Although presently not practised in Sweden, existing nuclear plants are technically capable of load-following and could potentially provide marginal generation in the future [44]. Including all nuclear in the short-run marginal mix in this study reduced the marginal emissions at the point of minimum LCOH for the base configuration by up to 97.5 %. Values for different marginal fuels in all bidding zones can be found in Table S6 in SM.

3.5. Benefits of dynamic EFs in electrolyser operation

The results from this study highlight some of the advantages of using dynamic EFs when determining the climate impact of hydrogen production systems, such as the reducing the carbon abatement cost and identifying differences in both average grid-mix and marginal emissions between the four Swedish bidding zones. Even so, the overall spatial and temporal variability of the emission factors was relatively low compared to those of other European countries determined using *elmada* (see [13] and Figure S2 in SM). In current conditions, utilisation of dynamic EFs in electrolyser operation in Sweden may in most contexts be somewhat redundant if accurate average or median values are available. Nonetheless, producing accurate aggregated values requires consideration of the dynamic and interconnected effects analysed in this study. The relatively high import share in some bidding zones means that considering both electricity imports and exports and zonal separation may give notable accuracy improvements in the average grid-mix case.

As the share of intermittent generation in power systems and EU ETS prices increase, the flexibility of remaining conventional generation in the northern European electricity system is likely to increase as well. Consequently, both nuclear power and CHP, which is increasingly biomass-driven, may be used for load following to a greater extent than currently. This would reduce the short-term marginal impacts of grid-operated hydrogen production as seen in Section 3.4 but also enable additional benefits from optimising electrolyser operation based on dynamic EFs. However, it is still uncertain how accurately SR-MEFs represent real marginal generation, particularly in hydropower-based systems.

Any practical application of dynamic EFs in operation of electrolyser systems would be greatly aided by the possibility of predicting future values. This has previously been demonstrated in [17] and [82], and by

Bokde et al. [33], who applied the concept specifically to electrolyser scheduling. Figures S4-S7 in SM reveal some seasonal and diurnal trends, especially for AEFs, indicating that forecasting could be possible to a degree. Further analysis of the EF data would be required to distinguish additional potentially relevant prediction variables. However, the effects of domestic electricity generation and price (described in Figures S11 and S12 in SM respectively) appear limited.

3.6. Implications of the EU's proposed regulatory framework for electrolyser operation

The Renewable Energy Directive II conferred upon the European Commission the power to adopt two delegated acts to define (a) the rules of electricity supply for the production of renewable hydrogen and (b) a methodology for assessing greenhouse gas emissions savings from hydrogen and its derivatives. The European Commission has adopted these delegated acts in early 2023, thus setting the criteria of what qualifies as renewable hydrogen within the European Union: renewable hydrogen production must procure electricity from newly constructed renewable generation units (either via a direct connection or by using power purchase agreements), from curtailed renewable grid electricity or from the grid in a bidding zone with an average grid-mix emission intensity lower than 18 gCO_2eq/MJ (64.8 gCO_2eq/kWh). Furthermore, the European Commission set out criteria of temporal correlation between the operation of the renewable generation unit and the electrolyser for different time horizons. For the period up to 1 July 2030 a monthly correlation was defined, while a more stringent hourly matching was proposed thereafter [83].

The four bidding zones (SE1–SE4) in Sweden had average AEF emission intensities 14.2, 15.6, 23.9 and 52.7 gCO_2eq/kWh respectively in 2018–2021, which makes Sweden exempt of the additionally criteria, i.e. the procurement of electricity from newly built renewable generation units. However, if the European Commission had opted for marginal emission factors, the emission intensities in all bidding zones would be way higher than the threshold established in the delegated act.

Using newly constructed renewable generation would avoid marginal impacts from shifting existing renewable generation and therefore ensure a low climate impact of the hydrogen, as would purchasing grid electricity during periods of renewable curtailment. However, our analysis has shown that even in a low-carbon region fulfilling the criteria of maximum 18 gCO_2eq/MJ the marginal generation mix may still be predominantly fossil-based if fossil generation is used in other regions within the interconnected system (Fig. 5, Fig. 8).

Furthermore, to facilitate the ramp-up of electrolyser deployment, the European Commission decided upon pressure of the European Parliament to start with a less strict monthly temporal correlation. [84]. The effects of this have been investigated in several recent studies. Schlund and Theile [35] demonstrated that anything but a direct matching of hydrogen production and renewable electricity generation could lead to increased specific marginal emissions of grid-based hydrogen in Germany. The dynamic EFs determined in the current study provided an opportunity to investigate the impact on the specific marginal emissions of hydrogen, i.e. the emissions specifically associated with electrolyser operation, as well as the LCOH for varying degrees of temporal matching in the Swedish case. For simplicity, the analysis was limited to purely grid-based operation. Using a modified version of the economic dispatch optimisation defined in Section 2.2.3 restricting the hydrogen production to correspond to the amount of wind energy generated within a given time interval (see Section S3.4 in SM) provided results similar to those in [35] and to those in [85] where system effects were also accounted for (Fig. 11). Extending the matching beyond an hourly basis increased the specific marginal emissions to more than 14 $kgCO_2eq/kgH_2$ while decreasing the LCOH by up to 26 %.

For electrolytic hydrogen production to enable the drastic reduction in emissions required by the Paris agreement, it should thus coincide with rapid expansion of renewable electricity generation to avoid emission increases in the short term. Because of this, we recommend the Swedish Government to consider a sooner phase-in of the hourly temporal correlation as part of its national implementation of the delegated acts, otherwise significant additional carbon emissions would occur due to marginal effects in the electricity grid.

3.7. Future research suggestions

In future research, studies on long-run MEFs for varying degrees of electrolyser deployment in the Nordic energy system are essential to determine its long-term climate impacts. Moreover, identifying prediction variables and subsequently forecasting EF values may enable actual emission-based operation for flexible hydrogen production systems. The impact of a specified hydrogen demand and potential energy storage on the economic and environmental trade-offs described in this study should also be investigated. Finally, the open-source nature of *elmada* and the electricity system model developed in this study enable dynamic MEF and AEF values to be determined for different countries within the interconnected European electricity system and used in other studies.

4. Conclusions

To investigate the dynamic spatial and temporal characteristics of grid electricity in Sweden and their potential effects on the climate impact of hydrogen production in the near future, this study applied the concept of dynamic emission factors to a grid-supported electrolytic hydrogen production system. Techno-economic analysis using a model of the integrated northern European electricity system showed that grid electricity could be utilised to decrease the levelised cost of wind-based hydrogen production with a wind-to-electrolyser ratio (WtE) of 1:1 in Sweden from 4.68 €/kgH_2 to 2.40–3.63 €/kgH_2 between 2018 and 2021. A trade-off between production cost and climate impact was identified, since in a short-term marginal perspective grid-based hydrogen production led to carbon emissions in excess of 20 $kgCO_2eq/kgH_2$ at lower levelised costs and consequently limited marginal CAC reductions from 276.8 €/tCO_2eq to 268.9–272.2 €/tCO_2eq. The identified trade-off between cost and marginal emissions could be mitigated by purchasing grid electricity based on the EFs which further reduced the lowest achievable marginal CAC of the system to 222.7 €/tCO_2eq in 2021. This impact was smaller in earlier years due to a reduced frequency of low-carbon marginal generation, increasing up to 255.8 €/tCO_2eq. Both cost and marginal emissions could also be reduced by increasing the WtE ratio, with a 5:1 ratio reducing the marginal CAC by to 119.3 €/tCO_2eq. Additional performance benefits were found in the northern bidding zones (SE1 and SE2) compared to the southern (SE3 and SE4). The average grid-mix perspective instead resulted in a low climate impact from all system configurations investigated and consequently average grid-mix CACs between 71.3 and 200.0 €/tCO_2eq. Lastly, following an analysis of proposed EU policy, strict hourly matching of purely grid-based electrolyser operation and renewable generation was judged to be important in ensuring a low marginal climate impact in the short term, at least if emission allocation from electricity sales or system effects are not accounted for, but it negatively affected economic performance as LCOH decreased by up to 26 % with less strict matching.

CRediT authorship contribution statement

Linus Engstam: Conceptualization, Methodology, Software, Formal analysis, Data curation, Writing – original draft, Visualization. **Leandro Janke:** Conceptualization, Methodology, Writing – review & editing, Supervision, Funding acquisition. **Cecilia Sundberg:** Conceptualization, Writing – review & editing, Supervision. **Åke Nordberg:** Conceptualization, Writing – review & editing, Supervision, Funding acquisition.

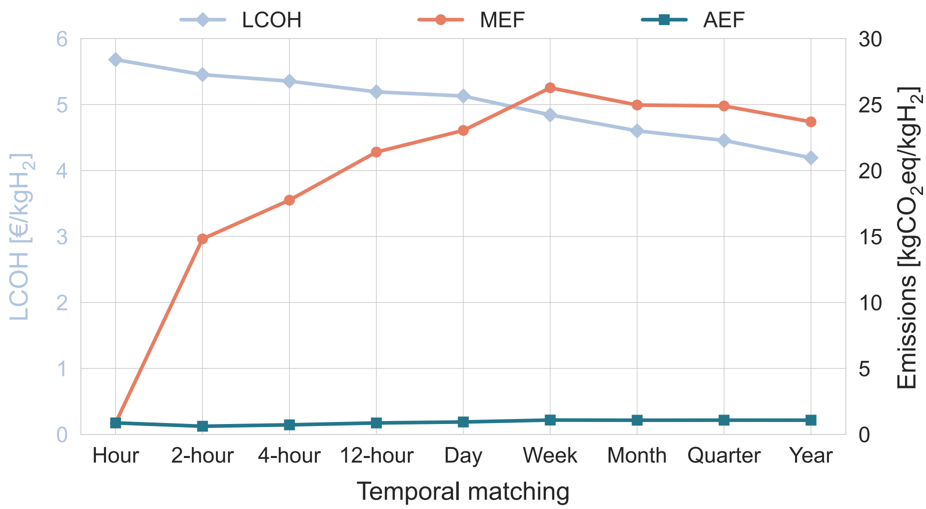

Fig. 11. Annual levelised cost of hydrogen (LCOH; light blue, left axis) and specific average grid-mix (AEF; teal, right axis) and marginal (MEF; orange, right axis) emissions from on-grid hydrogen production for varying degrees of temporal matching with wind power in Swedish bidding zone SE2 during 2021. Hourly matching was assumed to correspond to direct matching of hydrogen production and renewable generation since it is the smallest time step currently available on the Swedish electricity market.

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

A GitHub link has been provided in the supplementary material through which the models developed and data can be downloaded.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enconman.2023.117458.

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