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Interactions and distortions of different support policies for green hydrogen

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ABSTRACT

This paper explores various policies to support climate-neutral hydrogen production, focusing on their interaction with energy markets and cap-and-trade systems such as the EU emission trading scheme. We develop and deploy a state-of-the-art equilibrium model to examine the effect of hydrogen support policies on the interactions between hydrogen, electricity and emission markets. Our analysis shows that mechanisms remunerating hydrogen production can distort spot prices of electricity and hydrogen more strongly than mechanisms that remunerate hydrogen production capacity. Hydrogen support mechanisms furthermore promote renewable electricity production and deter investment in conventional generation assets. The associated decrease in emissions in the power sector leads to an increase of emissions in the industrial and hydrogen sector due to the waterbed effect in the EU emission trading scheme. Our case study on an emission-capped area inspired by the EU shows that the operational distortions that production-based mechanisms exhibit, typically increase costs more than the investment distortions that capacity-based mechanisms entail.

1. Introduction

Hydrogen and derived molecules generated through electrolysis can serve as energy carriers and chemical feedstock in a climate-neutral society. Especially in hard-to-abate industrial sectors and long-haul transport, these climate-neutral molecules can contribute to achieving established climate objectives. These molecules allow for the emission-free production of fertilisers and steel, facilitate innovative processes in the chemical industry, and may form the basis of sustainable synthetic fuels for shipping and aviation.

Many governments have announced ambitious hydrogen strategies to accelerate the deployment of climate-neutral production and end-use applications. Since climate-neutral hydrogen production technologies are not yet competitive with the traditional hydrogen production route, governments wish to subsidise the technologies required to produce hydrogen sustainably and consequently enable a climate-neutral industry. Economic justifications for subsidising hydrogen can be found in incomplete risk markets for emissions, electricity, and hydrogen; and in learning spillovers (Armitage et al., 2023; Nelson, 1959; Arrow, 1962).

Currently, little research is dedicated to the design of hydrogen subsidy mechanisms. Schlund and Schönfisch (2021) and Ricks et al. (2023) look into the effects of hydrogen subsidies and Roach and Meeus (2023) into possible interactions it may cause with carbon prices. However, it is known from previous research on renewable electricity subsidies that such interventions may lead to distortions in the dispatch of assets (Schmidt et al., 2013; Schlecht et al., 2024; Pahle et al., 2016) and investment decisions (Meus et al., 2021; Winkler et al., 2016; May, 2017).

The degree to which these distortions will manifest depends on the selected policy instrument. Because P-t-H technologies are dispatchable, one should be wary of any potentially distorting influence of these policy instruments on the operational decisions of hydrogen installations and technology choices. The discussion is further complicated because different electrolyser design choices lead to a trade-off between capital expenditures (CAPEX) and the efficiency of P-t-H facilities (IRENA, 2020). An optimal technology mix should align with the system's needs: low-CAPEX variants with a lower efficiency could, for instance, be preferred if vast amounts of cheap renewable electricity are available. However, certain subsidy designs might distort the optimal technology mix, as has been shown for renewable electricity instruments.

To investigate the impact of the aforementioned subsidy policies on energy markets and cap-and-trade systems, we extend the state-of-the-art long-term equilibrium model developed by Bruninx et al. (2020). The model captures the interactions between hydrogen, electricity and emission markets, to simulate the effect of different hydrogen support policies. The considered subsidy mechanisms are the following: (1) a 10-year fixed premium (EUR/MWh); (2) a 10-year hydrogen contract

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Nomenclature

Variables

$b_{y,f}$	Bought emission permits in year y by agent f, $MtCO_2eq$
$cp_{y,q}$	Capacity investment by electrolytic-hydrogen production agent q in year y, GW
$cp_{y,f}$	Capacity investment by fossil hydrogen production agent f in year y, GW
$g_{y,d,h,q}$	Electrolytic hydrogen production by agent q in year y, day d, and hour h, TWh
$g^{\mathrm{CfD}}_{y,q}$	Bid into H-CfD mechanism by agent q in year y, TWh
$g^{\mathrm{CG}}_{y,q}$	Bid into CAP mechanism by agent q in year y, TWh
$g_{y,d,f}$	Fossil based hydrogen production by agent f, for each year y, and day d, TWh
$g^{\mathrm{FP}}_{y,q}$	Bid into FP mechanism by agent q in year y, TWh
$g^{I}_{y,d}$	Hydrogen import in year y and day d, TWh
$g^{\mathrm{INV}}_{y,q}$	Bid into INV mechanism by agent q in year y, TWh

Prices

$\lambda^{\mathrm{EOM}}_{y,d,h}$	Price of the energy-only electricity market, for each year y, day d, and hour h, EUR/MWh
$\lambda^{\mathrm{ETS}}_{y}$	EU-ETS price in year y, EUR/tCO_2eq
$\lambda^{\mathrm{H_2}}_{y,d}$	Price of hydrogen, in each year y, and day d, EUR/MWh
$\lambda^{\mathrm{NG}}_{y}$	Price of natural gas in year y, EUR/MWh

Parameters

A_y	Annuity factor in year y
$\beta_{0,\mathrm{H_2}}$, $\beta_{1,\mathrm{H_2}}$	Coefficients of hydrogen import cost
CI_f	Carbon intensity of hydrogen production of agent f, tCO_2 eq/MWh
$\eta^{E\rightarrow \mathrm{H_2}}_{q}$	Electrolyser efficiency of agent q
$\eta^{\mathrm{NG}\rightarrow \mathrm{H_2}}_{f}$	Efficiency of converting natural gas to hydrogen of agent f
IC_q	Investment cost PtH agent q in year y, mEUR/GW
IC_f	Investment cost of fossil hydrogen production agent f in year y, mEUR/GW
$LT_{y,y^*,q}$	Mapping of investment year y to operational years y^* considering the lead time of agent q
$SV_{y,p}$	Salvage value of installation of agent q when salvaged in year y, mEUR/GW
$SV_{y,f}$	Salvage value of installation of agent f when salvaged in year y, mEUR/GW
$\Delta^{max.}_{f}$	Maximal y-o-y growth of SMR-CCS technology
$\Delta^{max.}_{q}$	Maximal y-o-y growth of PtH technology
HT	Imposed hydrogen target, TWh

Sets

$\mathcal{D}$	Set of representative days within a year
$\mathcal{F}$	Set of Fossil-based hydrogen production agents f (SMR en SMR-CCS)
$\mathcal{H}$	Set of hours within a day
$\mathcal{Q}$	Set of Electrolytic hydrogen production agents q (peak- and base-load)
$\mathcal{Q}^S$	Set of Electrolytic hydrogen production agents with government support (peak- and base-load)
$\mathcal{Y}$	Set of years considered in the model
$\mathcal{Y}^0$	Set of years considered in the model without the starting year

for difference (EUR/MWh); (3) a capacity grant (EUR/MW); (4) an investment subsidy (EUR/EUR). All mechanisms use an auction mechanism to determine the subsidy level. This selection was based on different variants of these mechanisms that are being implemented in different countries in practice. This will be covered in Section 2.3 in more detail.

A consistent quantitative comparison between hydrogen support mechanisms is lacking, and the analysis of hydrogen contract for difference (H-CfD) and capacity grants has not yet been conducted. Furthermore, the interactions that such mechanisms could trigger with existing EU climate policies have not yet been studied. Furthermore, our model considers low- and high-CAPEX variants of hydrogen production, allowing us to capture technology biases. The contribution of this paper can hence be summarised as: a first quantitative assessment of the impact of different hydrogen subsidy mechanisms, considering the interactions with the existing European climate policies, being the Renewable energy sources (RES) target and EU Emission trading scheme (EU ETS) whilst capturing distortions in both operational and investment decisions. Our results show that the operational distortions from production-based mechanisms are typically worse than the investment distortions that capacity-based mechanisms entail.

The remainder of this paper is structured as follows. In Section 2, background information is given on existing or proposed hydrogen subsidy mechanisms in the EU, US, and UK, as well as the remaining EU climate policy that is relevant for the analysis. Methods are outlined in Section 3 and results are presented and discussed in Section 4. Finally, conclusions are drawn in Section 6.

2. Hydrogen subsidy mechanisms

2.1. EU hydrogen policy

In the REPowerEU communication, the European Commission put forward ambitious goals for hydrogen production and end use (EC, 2022). By 2030 the commission aims to use 20 million tonnes (Mt) of hydrogen, of which 10 Mt should be produced domestically and 10 Mt imported via pipeline or ship, either as hydrogen or through chemical derivatives from hydrogen (e.g., ammonia, methanol, etc.). It is not clear from where the imports will be sourced at this stage. In addition to the quantity target of 10 Mt of domestically produced hydrogen, it puts forward the ambition to install 40 GW of electrolyser capacity. Note that these numbers were only communicated by the European Commission and not voted into law, hence they should be seen as an ambition and are prone to change.

In the third revision of the Renewable Energy Directive (RED III), these ambitions were partially translated into legally binding targets. By 2030, 42% of industrial hydrogen end-use needs to be from so-called renewable fuel of non-biological origin (RFNBO), which is electrolytic hydrogen (or further derivatives) that adhere to additional rules concerning the source of that electricity.[1] By 2035, the target for RFNBO use in the industry is set to 60%. For the transportation sector, a legally binding target of 1% RFNBO by 2030 was included.

2.2. Economic justifications

Economic justification for subsidising emerging climate-neutral technologies can be found in climate damages which are not accounted for in the decision-making of individual investors, leading to investment into polluting technologies without considering the impact these investments have on the climate. Even in regions like the EU that rely on carbon pricing to internalise carbon damages, emission markets may not internalise all market defects. This is because current carbon prices seem to be too low to reflect the social cost of carbon (Rennert et al., 2022) and additional market defects are present. Hence, subsidising said technologies can also be justified in regions with emission trading schemes in place.

We note two additional market defects, both related to the immature nature of hydrogen production technology. First, the risk markets for electricity (de Maere d'Aertrycke et al., 2017), carbon (Tietjen et al., 2021) and hydrogen are incomplete, and investors in electrolytic hydrogen cannot transfer their risk to market participants that are willing to take on the risk. Especially for hydrogen, the market is still nascent, and private entities are not offering hedging possibilities. The second economic justification for subsidising hydrogen, related to its immaturity, are learning spillovers. Learning reduces the future production cost of hydrogen, but may partially spill over and is hence not fully accounted for in the investors' decision-making process (Armitage et al., 2023; Fischer and Newell, 2008; Nelson, 1959; Arrow, 1962).

2.3. Support mechanisms

Numerous hydrogen support mechanisms have emerged in recent years in various regions and eligibility criteria for what is considered climate-neutral hydrogen, an overview is provided in Table 1. The United States put forward its first federal hydrogen subsidy mechanism as part of the Inflation Reduction Act of 2022 (IRA), which offers a tax credit to investors of "clean hydrogen".[2] Market participants would receive a fixed compensation above the market price at which they sell hydrogen.

In the UK, the Hydrogen Business Models are put forward as a hydrogen support scheme, which itself is part of a bigger support package called the Carbon Capture and Storage Infrastructure Fund, or CIF. Hydrogen Business Models aim to support both P-t-H and steam methane reforming equipped with carbon capture and storage (SMR-CCS) through a H-CfD that pays out the difference between a strike price and the market price of hydrogen for a duration of 15 years. The strike price is determined through a competitive auction between the participating projects, with separate baskets for P-t-H and SMR-CCS-based hydrogen.

In the EU, multiple mechanisms are set up to support hydrogen development. The innovation fund uses EU ETS revenues to support innovative technologies through lump-sum support grants on a project basis. Although intended for any innovative technology that can reduce emissions, the REPowerEU announcement specifically reserved part of the funding for hydrogen projects (EC, 2022).

The most significant European support mechanism in terms of available funding is the European Hydrogen Bank, which consists of two support mechanisms: one for domestic hydrogen production and one for hydrogen import (EC, 2023b). A first pilot auction for domestic hydrogen production was organised in 2023, with a budget of 800 MEUR (EC, 2023b), using an auctioned fixed premium with a duration of 10 years which they receive in addition to their market revenues. The first auction was organised according to pay-as-bid, and projects were selected from the supply curve solely on the basis of the price they bid until the budget was depleted. The auction attracted 132 bids of which 7 winners were selected that are supposed to produce 1.58 Mt H_2 over 10 years. The fixed premium of the highest winning bid was 0.48 EUR/kg H_2 (EC, 2024).

At the Member State level, Germany is setting up a scheme of its own called H2Global in which Belgium and The Netherlands also participate, where the government acts as a central buyer for hydrogen. Hydrogen production will be contracted at a fixed price using a Hydrogen purchase agreement (HPA), the price of which is determined through an auction. The government then sells the hydrogen to projects that can use hydrogen, and the difference between the buy and sell price is socialised. The contracts will have a duration of 10 years.

From Table 1 we observe a move away from support that is given on a project basis (capacity grants) in which support was often linked to the installed capacity, towards production-based subsidies in which actual hydrogen production is remunerated such as the IRA and EU Hydrogen Bank. Furthermore, since support budgets are increasing, governments move towards auction-based mechanisms such as the EU Hydrogen Bank, which allocates support more cost-effectively. What seems to be overlooked is organising support using an auction but remunerating based on capacity investments, a system that, as we will show later, has benefits compared to production-based mechanisms.

3. Methods

We formulate a partial equilibrium model with markets for electricity, hydrogen, emission certificates and RES certificates. We model different policies to attain a target for climate-neutral hydrogen production. Actors either produce electricity, produce hydrogen or abate emissions and participate in multiple markets depending on their production route. An overview of the actors in these markets and the interactions between them is provided in Fig. 1. It is a multiyear model with perfect foresight that runs from 2020–2060 and allows capacity expansion in the power and hydrogen sector. For additional information on out methods, we invite the reader to look into our documentation (Hoogsteyn et al., 2024). The main assumptions of our model include perfect competition, perfect foresight in all considered markets. The limitations that these assumptions bring will be discussed in Section 5.1.

3.1. Electricity & tradable RES certificate market

In the electricity market, investors in OCGT, CCGT, wind, solar, coal and nuclear generation compete and optimise their operation considering the variable generation of renewables and demand for electricity. The electricity market is an energy-only market, with hourly electricity prices steering the economic dispatch of conventional and renewable generation assets. Actors may invest in new generation capacity each year, to meet the growing demand for electricity. Fossil-based electricity generation agents must buy emission allowances for their emissions. RES agents have zero variable cost and no emissions, hence zero EU ETS compliance cost. RES agents can receive additional compensation through the certificate scheme that enforces a 69% share

[1] The rules for hydrogen to count as RFNBO specify that the used electricity for its production needs to be sourced either from a direct connection to RES, or in the case of a grid-connected setup, needs to adhere to rules concerning spatial and temporal correlation of the hydrogen and renewable electricity production, these rules will be phased in gradually (EC, 2023a).

[2] The maximum carbon intensity to be eligible for compensation is 4 kg of CO2 per kg of hydrogen (Podesta, 2022). The credit would amount up to 3$ per kg in 2023 for the 10 first years of operation, adjusted by 2% for inflation depending on the carbon intensity of the hydrogen.

Table 1
Overview of hydrogen support mechanisms.
Source: Adapted from Hughes and Martinez Hipolito (2023).

Name	Region	Type	Eligibility	Reference
Innovation Fund	EU	Capacity grant	Innovative nature	EC (2003)
Important projects of Common interest	EU	Capacity grant	Innovative nature	EC (2014)
Inflation Reduction Act	USA	Fixed-premium	<4 kg CO2/ kg H2	Podesta (2022)
Hydrogen Business models	UK	Hydrogen CfD	Blue & green H2	U.K. Department for Business (2022)
H2Global	DE	Hydrogen CfD	Ammonia import, methanol or SAF	Stiftung (2023)
Hydrogen Bank	EU	Fixed-premium	Defined in RED III	EC (2023b)

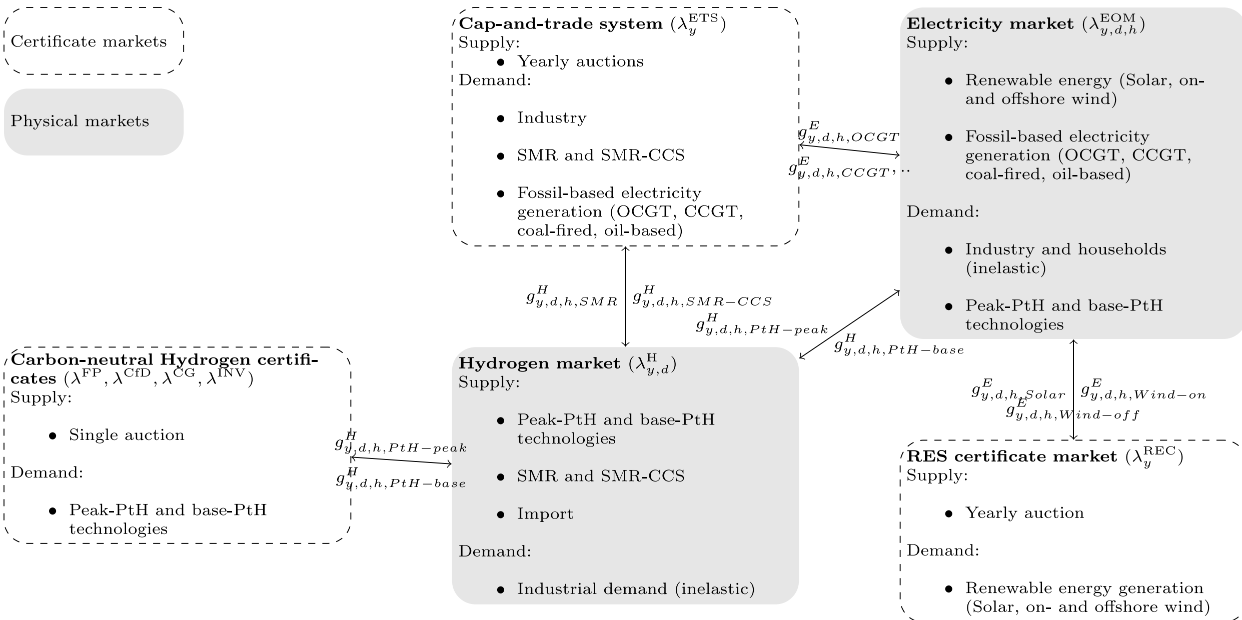


Fig. 1. Block diagram representation of the partial equilibrium model consisting of physical markets for hydrogen and electricity; and certificate markets for emission rights, renewable electricity and climate-neutral hydrogen.

of renewables in end-use electricity.[3] For additional details and a mathematical description on the representation of the power sector actors, the reader is referred to Bruninx et al. (2020).

3.2. EU ETS market model

We leverage the EU ETS market model from Bruninx et al. (2020), but exclude the market stability reserve (MSR), hence the cap is fixed. In this model, an industrial agent acts as a competitive fringe, while demand for emission allowances in the power sector and the hydrogen sector is endogenously modelled. The abatement cost of the competitive fringe is considered quadratic (linear increasing marginal cost). The industrial actor makes the trade-off between additional abatement and the cost of purchasing emission allowances. Emission certificates are bankable between different trading periods (years), but borrowing is prohibited. The MSR is not considered to retain the interpretability of the results. For details on the EU ETS model, the reader is referred to Bruninx et al. (2020).

3.3. Hydrogen market model

In the hydrogen market, investors in different renewable hydrogen production technologies compete with traditional steam methane reforming (SMR) technology and the possibility to import hydrogen. Hydrogen production $g_{y,d,h,q}$ by SMR, SMR-CCS and P-t-H is explicitly modelled and import ($g^I_{y,d}$) is represented using a linearly increasing marginal cost curve. A daily clearing of the hydrogen market is implemented, i.e., hydrogen demand and supply are matched with a daily granularity, as given by market coupling constraint (MCC) (1). The daily hydrogen demand $D^{\mathrm{H_2}}_{y,d}$ can be met by the P-t-H agents with ($\forall q \in \mathcal{Q}^S$) and without subsidy ($\forall q \in \mathcal{Q}$), fossil-based hydrogen agents ($\forall f \in \mathcal{F}$), and import. Note that short-term hydrogen storage is accounted for implicitly using this approach, without explicitly representing the storage capacity that is needed to accomplish the considered daily matching.[4]

$$\forall y \in \mathcal{Y}, \forall d \in \mathcal{D} : \sum_{q \in \mathcal{Q} \cup \mathcal{Q}^S} \sum_{h \in H} W_d \cdot g_{y,d,h,q} + \sum_{f \in \mathcal{F}} \cdot g_{y,d,f} + g^I_{y,d} = D^{\mathrm{H_2}}_{y,d} \quad (1)$$

3.3.1. Steam methane reforming production route

SMR and SMR-CCS agents ($\forall f \in \mathcal{F}$) optimise their hydrogen production $g_{y,d,f}$ and investment decisions $cp_{y,f}$ so that their profits are maximised, considering their revenues from the hydrogen market with price $\lambda^{\mathrm{H_2}}_{y,d}$ and the exogenously set price of natural gas λ^{NG}_y. Furthermore, IC_q is the investment cost, CI_f represents the carbon intensity of hydrogen production, $b_{y,f}$ represents the number of emission permits purchased, $\eta_f^{\mathrm{NG}\to\mathrm{H_2}}$ represents the efficiency of converting natural gas to hydrogen, and $LT_{y,y^*,q}$ is a square matrix that maps the years in which capacity investments can occur (y) to the years in which that capacity is present (y^*), considering the lifetime and investment lead time. $\overline{cp_{y,f}}$ denotes the legacy capacity present, that is gradually phased out. For

[3] Which was put forward as ambition in REPowerEU (EC, 2022).

[4] This approach helps address the uncertainty surrounding the technical capabilities to store hydrogen and at what cost.

the SMR and SMR-CCS agents $\forall f \in \mathcal{F}$, the optimisation problem given by Eqs. (2)–(6) is solved, where Eq. (3) limits the daily hydrogen generation to the installed capacity. Eq. (4) imposes that in any given year, the agent has bought more emission rights than it emitted up to that year. Eq. (5) imposes a limit on each years capacity investment based on the cumulative capacity prior and a growth limit $\Delta_f^{max.}$, which allows us to study limits on the growth trajectory of SMR-CCS to mimic manufacturing capabilities.

$$\forall f \in \mathcal{F}: \max_{g_{y,d,f},\, b_{y,f},\, cp_{y,f}} \sum_{y\in\mathcal{Y}} A_y \sum_{d\in D} W_d(\lambda_{y,d}^{\mathrm{H_2}} \cdot g_{y,d,f} - \lambda_y^{\mathrm{NG}} \cdot \frac{g_{y,d,f}}{\eta_f^{\mathrm{NG}\rightarrow \mathrm{H_2}}}) - (1-SV_{y,f}) \cdot IC_f \cdot cp_{y,f} - \lambda_y^{\mathrm{ETS}} \cdot b_{y,f} \tag{2}$$

Subject to

$$\forall y \in \mathcal{Y}, \forall f \in \mathcal{F}, \forall d \in \mathcal{D}: g_{y,d,f} \leq \sum_{h\in\mathcal{H}} (\sum_{y^*=1}^{y} LT_{y,y^*,f} \cdot cp_{y^*,f} + \overline{cp_{y,f}}) \tag{3}$$

$$\forall y \in \mathcal{Y}, \forall f \in \mathcal{F}: \sum_{y^*=1}^{y} \sum_{d\in D} W_d \cdot CI_f \cdot \frac{g_{y,d,f}}{\eta_f^{\mathrm{NG}\rightarrow \mathrm{H_2}}} \leq \sum_{y^*=1}^{y} b_{y^*,f} \tag{4}$$

$$\forall y \in \mathcal{Y}^0, \forall f \in \mathcal{F}: cp_{y,f} \leq \Delta_f^{max.} \sum_{y^*=1}^{y} LT_{y,y^*,q} \cdot cp_{y^*,q} + \overline{cp_{y,q}} \tag{5}$$

$$\forall y \in \mathcal{Y}, \forall d \in \mathcal{D}, \forall f \in \mathcal{F}: g_{y,d,f},\ b_{y,f},\ cp_{y,f} \geq 0 \tag{6}$$

3.3.2. Green hydrogen import

Green hydrogen import is represented by an agent that acts as a competitive fringe with linearly increasing marginal cost. This approach incorporates the observation that the marginal import cost increases with import volumes, due to sourcing from more distant countries and more expensive carriers. This approach helps cope with the uncertainty of import costs and the technical and economical feasibility of import through different carriers. Note that this hydrogen does not count towards reaching the domestic hydrogen target that is imposed in the cases where subsidies are considered. For the hydrogen import agent, its decision problem is given by Eqs. (7)–(8), where $g_{y,d}^I$ denotes the quantity of hydrogen import.

$$\max_{g_{y,d}^I} \sum_{y\in\mathcal{Y}} A_y \sum_{d\in D} W_d(\lambda_{y,d}^{\mathrm{H_2}} \cdot g_{y,d}^I - \beta_{0,H_2} \cdot g_{y,d}^I - \beta_{1,H_2} \cdot (g_{y,d}^I)^2) \tag{7}$$

Subject to

$$\forall y \in \mathcal{Y}, \forall d \in \mathcal{D}: g_{y,d}^I \geq 0 \tag{8}$$

3.3.3. Power-to-hydrogen agents without subsidy

Two power-to-hydrogen actors (peak- and base-load, $\forall q \in \mathcal{Q}$) aim to optimise their hydrogen hourly generation $g_{y,d,h,q}$ and yearly capacity investments $cp_{y,q}$ to maximise their profit $P(g_{y,d,h,q},\ cp_{y,q})$ given by Eq. (10). $\lambda_{y,d,h}^{\mathrm{EOM}}$ represents the price of electricity, $\eta_t^{P\rightarrow H_2}$ represents the electrolyser efficiency, IC_q the electrolyser investment cost and $SV_{y,p}$ the salvage value. The P-t-H agents without subsidies maximise Eq. (9) subject to Eq. (11) which limit hydrogen production to the installed capacity and Eq. (12) implements a growth limit $\Delta_q^{max.}$ based on the cumulative installed capacity.

$$\forall q \in \mathcal{Q}: \max_{g_{y,d,h,q},\, cp_{y,q},} P(g_{y,d,h,q},\ cp_{y,q}) \tag{9}$$

With

$$P(g_{y,d,h,q},\ cp_{y,q}) = \sum_{y\in\mathcal{Y}} A_y \sum_{d\in D} (W_d \sum_{h\in\mathcal{H}} \lambda_{y,d}^{\mathrm{H_2}} \cdot g_{y,d,h,q} - \lambda_{y,d,h}^{\mathrm{EOM}} \cdot \frac{g_{y,d,h,q}}{\eta_t^{P\rightarrow H_2}}) - (1-SV_{y,p}) \cdot IC_q \cdot cp_{y,q} \tag{10}$$

Subject to

$$\forall y \in \mathcal{Y}, \forall d \in \mathcal{D}, \forall h \in \mathcal{H}, \forall q \in \mathcal{Q}: g_{y,d,h,q} \leq \sum_{y^*=1}^{y} LT_{y,y^*,q} \cdot cp_{y^*,q} + \overline{cp_{y,q}} \tag{11}$$

$$\forall y \in \mathcal{Y}^0, \forall q \in \mathcal{Q}: cp_{y,q} \leq \Delta_q^{max.} \sum_{y^*=1}^{y} LT_{y,y^*,q} \cdot cp_{y^*,q} + \overline{cp_{y,q}} \tag{12}$$

$$\forall y \in \mathcal{Y}, \forall d \in \mathcal{D}, \forall h \in \mathcal{H}, \forall q \in \mathcal{Q}: g_{y,d,h,q},\ cp_{y,q} \geq 0 \tag{13}$$

3.4. Support mechanisms

The model aims to represent agents that receive support but operate in a competitive market. To capture this behaviour, we consider additional agents ($q \in \mathcal{Q}^S$) for which the aforementioned profit $P(g_{y,d,h,q},\ cp_{y,q})$ is augmented with income through various subsidy mechanisms. We only consider P-t-H technology climate-neutral, since SMR-CCS has residual emissions. We do not enforce additional constraints on the sourcing of the electricity, such as those defined in RED III.

We consider two variants of production-based instruments that use long-term support contracts to enforce quantity targets. One is through a fixed premium, and the other is a hydrogen contract for difference. Furthermore, two capacity-based mechanisms are investigated, a capacity grant that renumerates on the basis of installed electrolyser capacity and an investment subsidy, which renumerates a percentage of the investment cost. An overview is given in Table 2 of all policies considered and variants thereof. Each considered policy is calibrated to yield the same amount of climate-neutral hydrogen production HT over the duration of the considered contract ($\forall y \in \mathcal{Y}_T$) by the supported agents ($\forall q \in \mathcal{Q}^S$). The contracted hydrogen must be produced from a capacity investment in the year the tender takes place cp_q^{T}. The equilibrium price of the subsidy mechanisms is determined through the market coupling constraint Eq. (14), which makes sure that a user-defined amount of hydrogen (HT) is produced by the agents that receive subsidy.

$$\sum_{q\in\mathcal{Q}^S} \sum_{\forall y\in\mathcal{Y}_T} \sum_{d\in D} W_d \sum_{h\in\mathcal{H}} g_{y,d,h,q} = HT \tag{14}$$

3.4.1. Fixed premium

This mechanism can be interpreted as a system in which P-t-H operators keep their revenues from selling hydrogen and receive a fixed compensation per produced quantity of hydrogen for the contract duration. The fixed premium is determined through an auction in which operators can offer a certain amount of climate-neutral hydrogen production [Mt]. The premium thus includes the necessary cost compensation (CAPEX and operational expenditures (OPEX)) needed to reach a certain production target in the year the auction is organised.

This mechanism is implemented as follows: $g_{y,q}^{\mathrm{FP}}$ represents the amount of generation that is offered to an auction, the actor then receives the fixed premium λ^{FP} for its generation in the years that are covered under that contract ($\forall y \in \mathcal{Y}_T$). In contrast to P-t-H agents without subsidies, investment can occur only in the year the auction takes place cp_q^{T}. Note that the compensation received through the mechanism is annualised using the year y it is received. Constraint (16) ensures that the total generation in each year exceeds the amount that has been offered to the auction. Note that the actor hence has the freedom to choose in which years production is concentrated, as long as the cumulative amount has been produced over the contract duration.

$$\forall q \in \mathcal{Q}^S: \max_{g_{y,d,h,q},\, cp_q^{\mathrm{T}},\, g_{y,q}^{\mathrm{FP}}} P(g_{y,d,h,q},\ cp_{y,q}) + \sum_{\forall y\in\mathcal{Y}_T} A_y \cdot \lambda^{\mathrm{FP}} \cdot g_{y,q}^{\mathrm{FP}} \tag{15}$$

Subject to (11), (12), (13) and:

$$\forall y \in \mathcal{Y}_T, \forall q \in \mathcal{Q}^S: g_{y,q}^{\mathrm{FP}} \leq \sum_{d\in D} W_d \sum_{h\in\mathcal{H}} g_{y,d,h,q} \tag{16}$$

$$\forall y \in \mathcal{Y}_T, \forall q \in \mathcal{Q}^S: g_{y,q}^{\mathrm{FP}} \geq 0 \tag{17}$$

Furthermore, two variants on the fixed premium will be investigated. The first one limits the duration for which support can be received to a

Table 2
Overview implemented support mechanisms.

Abbrev.	Description	Renumeration	
Ref.	No support policy case	–	–
FP	Fixed premium	Production	EUR/MWh
CfD	Hydrogen contract for difference	Production	EUR/MWh
CG	Capacity grant	Capacity	EUR/MW
INV	Investment subsidy	Capacity	EUR/EUR
FP-30k	Fixed premium with support limited to 30,000 h	Production	EUR/MWh
FP-40k	Fixed premium with support limited to 40,000 h	Production	EUR/MWh
FP-50k	Fixed premium with support limited to 50,000 h	Production	EUR/MWh
FP-fix	Fixed premium in which yearly volumes are kept constant	Production	EUR/MWh

predetermined amount of full load hours h^{max}, e.g., support can only be received during the first 30,000 h of operation. This effectively limits the P-t-H to receive subsidy for approximately $3000h/y$, and as such hopes to avoid producing during high electricity price periods, which are typically correlated with low renewable output. Such limits also act as safegaurds against over-subsidisation because they limit the support given in cases where the utilisation rate is higher than anticipated. Eq. (18) is enforced in addition to Eqs. (11), (12), (13), (16) and (17)

$$\forall q \in \mathcal{Q}^S: \sum_{\forall y \in \mathcal{Y}_T} g^{\mathrm{FP}}_{y,q} \leq h^{max} \cdot cp^{\mathrm{T}}_q \tag{18}$$

In the second variant we impose that each year the same hydrogen production needs to be produced. This is done by enforcing Eq. (19) in addition to Eqs. (11), (12), (13), (16) and (17).

$$\forall y \in \mathcal{Y}^0, \forall q \in \mathcal{Q}^S: g^{\mathrm{FP}}_{y,q} = g^{\mathrm{FP}}_{y-1,q} \tag{19}$$

3.4.2. Hydrogen contract for difference

The other long-term contract instrument considered is a 10-year two-sided contract for difference with the yearly average hydrogen price as the reference price. In this mechanism, P-t-H operators keep their revenues from selling hydrogen at the daily price and receive compensation according to the difference between a fixed strike price and the average yearly hydrogen price, per produced quantity of hydrogen for the first 10 years of the lifetime of the investment. The strike price is fixed for the duration of the contract and is determined through an auction, where operators can offer a certain generation of climate-neutral hydrogen to be covered under the CfD.

The mechanism is implemented as follows, $g^{\mathrm{CfD}}_{y,q}$ represents the amount of generation that is covered under the auction. The actor then receives the difference between the strike price λ^{CfD} of the auction and the average annual hydrogen price $\lambda^{\mathrm{H_2},ref}_y$ for its generation in the years that are covered under that contract ($\forall y \in \mathcal{Y}_T$). Note that this difference can become negative.

$$\forall q \in \mathcal{Q}^S: \underset{g_{y,d,h,q},\, cp^{\mathrm{T}}_q,\, g^{\mathrm{CfD}}_{y,q}}{\mathrm{Max.}} P(g_{y,d,h,q},\ cp_{y,q}) + \sum_{\forall y \in \mathcal{Y}_T} A_y \cdot (\lambda^{\mathrm{CfD}} - \lambda^{\mathrm{H_2},ref}_y) \cdot g^{\mathrm{CfD}}_{y,q} \tag{20}$$

Subject to (11), (12), (13) and:

$$\forall y \in \mathcal{Y}_T, \forall q \in \mathcal{Q}^S: g^{\mathrm{CfD}}_{y,q} \leq \sum_{d \in D} W_d \sum_{h \in \mathcal{H}} g_{y,d,h,q} \tag{21}$$

$$\forall y \in \mathcal{Y}_T, \forall q \in \mathcal{Q}^S: g^{\mathrm{CfD}}_{y,q} \geq 0 \tag{22}$$

3.4.3. Capacity grant

In the capacity grant mechanism, the support level λ^{CG} is determined through an auction that ensures that a hydrogen production target HT is produced through P-t-H, similar to the previous mechanisms, but the remuneration is based on its capacity investment cp^{T}_q.

$$\forall q \in \mathcal{Q}^S: \underset{g_{y,d,h,q},\, cp^{\mathrm{T}}_q}{\mathrm{Max.}} P(g_{y,d,h,q},\ cp_{y,q}) + A_y \cdot \lambda^{\mathrm{CG}} \cdot cp^{\mathrm{T}}_q \tag{23}$$

3.4.4. Investment subsidy

In the investment subsidy mechanism, the subsidy is a percentage of the investment cost IC_q and is determined in an auction system that ensures a hydrogen production target HT is reached.

$$\forall q \in \mathcal{Q}^S: \underset{g_{y,d,h,q},\, cp^{\mathrm{T}}_q}{\mathrm{Max.}} P(g_{y,d,h,q},\ cp_{y,q}) + A_y \cdot \lambda^{\mathrm{INV}} \cdot IC_q \cdot cp^{\mathrm{T}}_q \tag{24}$$

3.5. Solution strategy

To solve this mixed complementary problem, we employ a price search algorithm inspired on alternating direction methods of multipliers (ADMM) of Boyd (2010) following Höschle et al. (2018) and Bruninx et al. (2020) which iteratively finds the equilibrium prices for the physical markets (electricity and hydrogen) and certificate markets that enforce the policy targets (cap-and-trade system, RES support, and hydrogen support). For a full description of our solution strategy, we invite the reader to look into our documentation (Hoogsteyn et al., 2024). The equilibrium price of the support policies (λ^{FP}, λ^{CfD}, λ^{CG} and λ^{INV}) at which Eq. (14) is met, is found through the iterative ADMM procedure as well. ADMM determines the equilibrium by evaluating the imbalance between the left and right hand side of the market coupling constraints (14) and (1), and updating the equilibrium prices in the direction that reduces this imbalance until equilibrium is reached. A penalty term is added which helps guarantee convergence to the equilibrium. Convergence was verified by evaluating the Karush–Kuhn–Tucker (KKT) conditions ex-post.

3.6. Case study setup

We consider a case study with an EU scope, that uses aggregate electricity demand, wind availability, and solar availability profiles. The modelled horizon is 2023–2060. To compare the support policies, we consider a case in which a total of 150 Mt H_2 is contracted in a single auction held in 2029, which covers hydrogen production from 2030 till 2040. For each hydrogen support policy, the equilibrium price is determined at which the peak- and base-P-t-H agents that participate in the auction jointly produce 150 Mt of hydrogen. The investment lead time for P-t-H is considered equal to 1 year and equal to the tender lead time for simplicity. After 2040, assets still have a lifetime of 10 years, during which they can still earn market revenues.

The installation cost of alkaline electrolysers has been estimated to be 500–1000 EUR/kW by IRENA and 750-1300/kW by IEA (2022). Other P-t-H technologies include proton exchange membrane (PEM) and solid oxide electrolyser (SOE). We do not consider SOE because of its low technological readiness. PEM technology has a higher technology readiness and the advantage of being more flexible to operate. However, this paper aims to focus on the trade-off in CAPEX and OPEX within the technologies rather than investigating additional benefits that one technology could bring over another. See Table 3 for the assumptions made with respect to hydrogen production technologies.[5]

[5] The CI of SMR-CCS is based on a capture rate of 90% (IEA, 2022).

Table 3
Overview assumptions on hydrogen production.

Technology		SMR Janssen (2018)	SMR-CCS	P-t-H-peak IEA (2022)	P-t-H-base IEA (2022)
Investment cost	MEUR/GW_e	740	1000	750	1000
Lead time	years	3	3	3	3
Lifetime	years	25	25	20	20
Learning rate	IC % change YoY	–	–	2%	2%
Efficiency		75%	62%	60%	70%
Carbon intensity	tCO_2/MWh	0.328	0.0328	0	0
Legacy capacity	GW	70	0	1	1

Table 4
To assess the robustness of our conclusions a list of sensitivities is investigated alongside the central reference case.

Name	Description	Parameter	Scaling
Low natural gas price	50% decrease in natural gas price	λ_y^{NG}	0.50
Expensive Import	50% increase in import cost	$\beta_{0,H2}$	1.5
No buildout limits	No growth limits on P-t-H and SMR-CCS	$\Delta_q^{max.}, \Delta_f^{max.}$	10
Low P-t-H buildout	max. 75% y-o-y growth in P-t-H	$\Delta_q^{max.}$	0.75
Low RES buildout	max. 20% y-o-y growth in RES	$\Delta_q^{max.}$	0.40
Expensive base-P-t-H	50% increase in investment cost base P-t-H	IC_q	1.5
Expensive peak-P-t-H	50% increase in investment cost peak P-t-H	IC_q	1.5

We will refer to a low-CAPEX, high-OPEX as 'peak-P-t-H', and high-CAPEX, low-OPEX as 'base-P-t-H'. The lifetime of P-t-H was based on the reported 60000 h lifetime of Alkaline electrolysers by IRENA (2020).

The commodity prices that are exogenous to our model, such as natural gas, were based on historical prices where applicable, on future prices where available, and otherwise on projections done by ENTSO-E.[6] Electricity demand profiles from ENTSO-E were used of which 16 representative days were selected for each modelled year based on demand, solar and wind availability, according to the approach of Gonzato et al. (2021) and Poncelet et al. (2017). The hydrogen demand is imposed, that is, perfectly inelastic, and grows linearly from 10Mt in 2020 to 20Mt in 2030 and 50Mt in 2050.[7] Within one year, a flat demand profile for hydrogen is assumed.

The abatement cost curve of the industrial fringe is calibrated such that the model reproduces an emission allowance price of 80 EUR/tCO_2 in 2022.[8] Similarly, the quadratic hydrogen import cost curve is chosen such that the minimal marginal import cost is 100 EUR/MWh and increases such that it yields 10 Mt hydrogen import. The coefficients $\beta_{0,H2}$ and $\beta_{1,H2}$ are selected such that 10Mt of import is present in 2030,[9] in line with the REPowerEU communication (EC, 2022).

The robustness of the effects observed in our reference case is assessed by performing a series of sensitivity analyses. A list of those sensitivities is given in Table 4 and includes perturbations to natural gas prices, hydrogen import cost, the relative investment cost of the peak- and base-P-t-H and maximal growth rates of P-t-H and RES. We explored a multitude of sensitivities but selected these final eight based on the uniqueness of their hydrogen generation mix compared to the reference case. The sensitivity analysis is performed ceteris paribus.

[6] Gas price projections used (in reference case): 48.7EUR/MWh for 2024, 42.0EUR/MWh for 2025 based on ICE TTF Gas Futures (Accessed on 20th of March 2023), 46.1 EUR/MWh for 2026, 45.5 EUR/MWh for 2027, 45 EUR/MWh for 2028, 44.5 EUR/MWh for 2028 and 43.9 EUR/MWh used from ENTSOE (2022). A coal price of 26.91 EUR/MWh was used. The marginal cost of nuclear generation was assumed to be 10 EUR/MWh.

[7] That is in line with the historic hydrogen demand including derivatives in 2020 and the EU commissions ambition for 2030 and 2050, EC (2022), see Section 2.1.

[8] The competitive fringe has a marginal abatement cost $MAC = \beta \cdot a_y$, with a_y the abatement in a given year in Mt. The marginal cost coefficient β was determined iteratively to be 0.7697.

[9] $\beta_{0,H2}$ was taken 100 EUR/MWh and $\beta_{1,H2}$ was found iteratively to be 35,9 EUR/MWh^2 with $g^I_{y,d}$ in MWh.

4. Results

In Section 4.1 the outcomes of the no support case are presented, i.e. the market equilibrium without any subsidy instruments, which will serve as reference. We present this result for all sensitivities. The subsequent sections are dedicated to the main results where subsidy policies are applied. In particular, Section 4.2 shows how different subsidy mechanisms change the mix of hydrogen production technologies. In Section 4.4 the effect on the power sector is discussed, looking at the operational distortions that the policies create. In Section 4.5 the impact on prices and emissions in the emission trading scheme are given, and finally in Section 4.6 the policies are compared according to the total cost of the system, allowing us to quantify the magnitude of the different distortions.

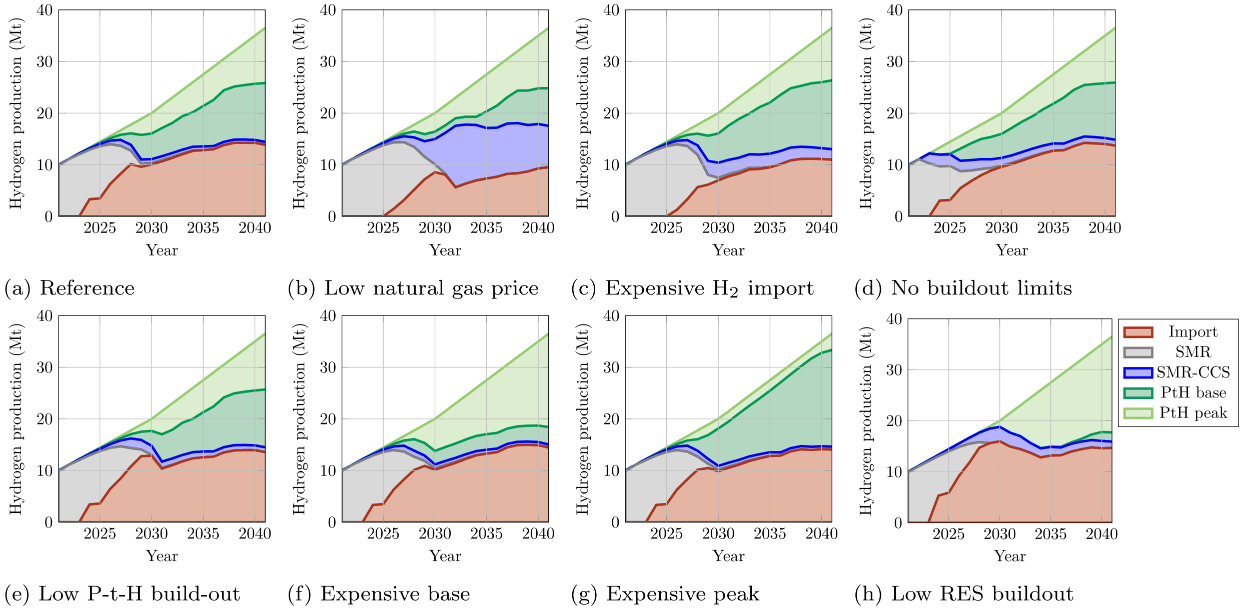
4.1. No support policy cases

In the hydrogen sector, SMR-based hydrogen production is gradually phased out in favour of import and electrolytic hydrogen. During 2023–2040, 70 Mt H_2 is produced via SMR and 170 Mt is produced by P-t-H. Investments in SMR-CCS only contribute 12.4 Mt until 2040 in the reference scenario, and 180 Mt is imported (Fig. 2(a)). We observe that, similarly to power systems, an optimal mix of high-CAPEX low-OPEX and low-CAPEX high-OPEX P-t-H technologies arises. By 2030, 2416 TWh is supplied by solar and wind in the power sector, 624 TWh by other RES,[10] and 522 TWh by non-renewable generation (not shown in figure).

In Figs. 2(b)–2(h), the model results for the sensitivities are shown for the reference cases, i.e. no hydrogen support, are presented.[11] In the scenario with low natural gas prices, SMR-CCS plays a major role in lowering carbon dioxide (CO_2) emissions from the hydrogen sector, contributing 111.0 Mt in 2023–2040 while P-t-H contributes 121.2 Mt. In the case of expensive hydrogen import, import reduces to 121.5 Mt and is substituted for P-t-H and SMR-CCS. When no limits are applied on the uptake of P-t-H and SMR-CCS, the phase-out of SMR is accelerated. The cases with more expensive peak or base P-t-H lead to less investment in the respective technology. When the maximum

[10] Most notably hydro and waste incineration, which are exogenous to the model, but count towards the 2030 RES target set by the EU.

[11] Various sensitivities were omitted, as they did not yield a solution that was considerably different from the reference case: high P-t-H cost, low natural gas prices, cheap RES, expensive RES, cheap import.



(a) Reference (b) Low natural gas price (c) Expensive H_2 import (d) No buildout limits

(e) Low P-t-H build-out (f) Expensive base (g) Expensive peak (h) Low RES buildout

Fig. 2. Annual H_2 production in (a) the reference case and an overview of the sensitivities (b–h).

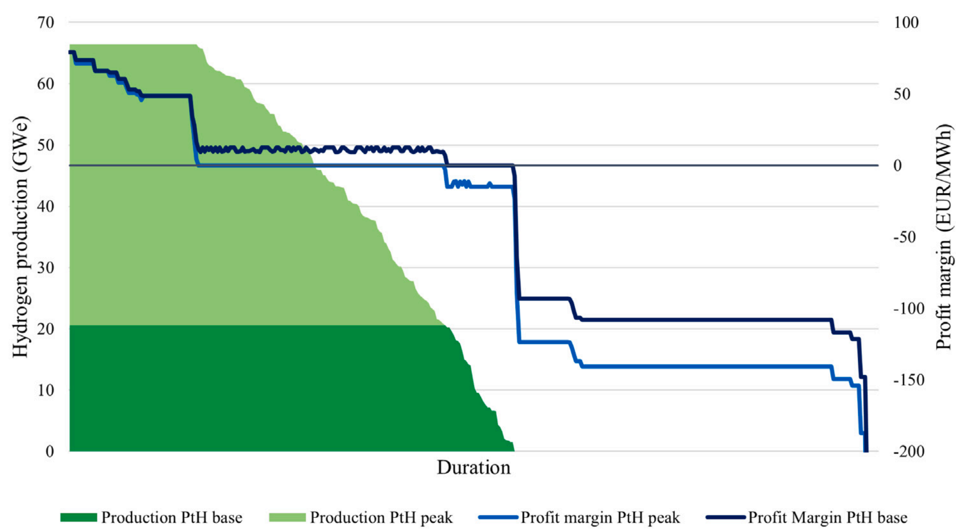


Fig. 3. Hydrogen production duration curve of the hydrogen sector that shows the dispatch of the peak and base P-t-H technology as well as their profit margin during the year 2030, without subsidies applied, in the reference case.

growth rate in renewable electricity was limited to 20%, P-t-H-based hydrogen production is delayed to later years and is mostly substituted for import, and for SMR-CCS to a lesser extent.

In Fig. 3, a load duration curve of the hydrogen production is shown, which shows the growing energy demand of the peak and base P-t-H technology. Each value represents a modelled hour sorted from high to low operational profit margin. Their operational profit margin is given by the difference between the hydrogen and electricity prices during that hour, considering the efficiency of the technology variant. During the hours that P-t-H technologies are partially dispatched, they are price setting in the electricity market and they have a zero profit margin during these hours.

4.2. Investment distortions in the hydrogen sector

Fig. 4 presents the PtH capacity investments attracted by the tender and shows that both the base and peak technologies are attracted by all mechanisms. However, the capacity and investment-based instruments tend to install moderately more capacity to obtain the same quantity of hydrogen. Especially for the investment subsidy, additional capacity investments occur (3%–9% w.r.t. FP). Furthermore, the additional capacity is mostly peak technology from both the CAP and INV mechanisms, which indicates that these policies have a selection bias towards the cheaper peak unit, which was expected for the CAP, but contrary to the expectations for the INV mechanism. For INV a selection bias towards CAPEX heavy technologies is expected for an investment subsidy because the remuneration of the mechanism is proportional to its CAPEX cost, this was only observed in a single sensitivity (expensive peak P-t-H). To understand this behaviour, we would like to highlight that the INV mechanism attracts more base w.r.t. CAP, which indicates that it does favour CAPEX heavy technologies, it simply is cost-optimal to reach the imposed HT by placing more peak under the auction mechanism as well, so that the same peak to base proportion can be maintained. In the full results that are given in the supplementary material, it is shown that on a system level, the same amount of peak

Fig. 4. P-t-H investments by the hydrogen auction participants depending on the used support policy (top) and the utilisation of the assets during 2031 (bottom) in the reference case (bars) and the sensitivities (crosses).

capacity is attracted, rather there is simply placed more under the auction mechanism.

Looking at the variants of the FP mechanism shown in Fig. 4 reveals that constraining the number of full load hours in which support can be received increases the installed capacity. In these cases, the hydrogen production for which subsidies can be received is limited by a fixed number of hours (e.g., 30,000 h) multiplied by the rated capacity, hence under such a mechanism agents have an incentive to increase their installed capacity. Fixing the hydrogen production level throughout the years in the contract (FP-fix) increases the P-t-H capacity. This happens because the additional constraint on the production profile of the P-t-H operators enforces them to deviate from their cost-optimal path, leading to an increased subsidy to compensate for that. Higher subsidies lead to higher investments.

4.3. Operational distortions in the hydrogen sector

Fig. 5 presents price duration curves of electricity and hydrogen in 2031 and shows that support policies tend to increase electricity prices and decrease hydrogen prices, compared to the price duration curve when no subsidies are applied (dotted line). Capacity-based and investment-based mechanisms have less impact on electricity prices. This underscores that such mechanisms primarily drive capacity investments to produce the contracted volume, rather than exert a significant influence on market prices. In contrast, production-based instruments remunerate actual hydrogen production, which increases their willingness to pay for electricity, and thus exerts a more pronounced effect on electricity prices, particularly when they serve as price-setters. In the considered sensitivities, the subsidy levels needed to reach the 150 Mt target are between 0.62–1.44 EUR/kg H_2 in the FP case, consequently increasing electricity prices. Nevertheless, all hydrogen subsidy mechanisms lower electricity prices during those hours when P-t-H prevents more expensive technologies from being price-setting.

All hydrogen support mechanisms decrease hydrogen prices because of the subsidy that is passed through in the market price of hydrogen. In instances where import is price setting, a decrease is observed because subsidising domestic production replaces import, which decreases the marginal cost of import, given that it is assumed linear. For production-based mechanisms, negative hydrogen prices were observed in cases where marginal electricity prices were zero yet incentives remain in place to produce hydrogen. Also in the CAP and INV cases, incentives remained to produce during hours with negative prices. During these hours, paying to produce is cheaper than installing more capacity. Negative prices are unlikely to occur in a realistic setting and are rather an artefact of the inelastic hydrogen demand.

As can be seen from the dispatch decisions in the electricity market (Fig. 5), no gas-fired generation assets were dispatched due to the increase in the electricity price, even in the case of production-based subsidies. In the hydrogen market, however, the subsidy was high enough in certain instances to dispatch the peak technology with subsidy before the base technology without subsidy (not shown in the figure), which is a suboptimal decision from a system perspective. This effect also explains the selection towards peak technology in the case of the FP-fix variant, where the fixed premium was higher, making the effect more pronounced (Fig. 4).

4.4. Impact on the power system

In Fig. 6, the impact on the power system is shown. In the figure on the left, the changes in cumulative production source until 2040 are shown compared to the reference scenario without subsidies. Reaching the 150 Mt target of climate-neutral hydrogen requires in the central reference case an additional 14.7 Mt H_2 to be produced by the subsidy-covered agents. This demands an additional 896 TWh in case of a FP, 941 TWh in case of a H-CfD, 848 TWh in the CAP case, and 905 TWh in the INV case. These variations can be explained by the different total hydrogen production resulting from the different policies. Although 150 Mt is contracted under the support schemes in each case, the policies affect the profitability of producing hydrogen without subsidy. The P-t-H targets decrease production of gas-fired generation, this can be explained by the increased attractiveness of renewables when dispatchable load P-t-H is added to the system (Fig. 6).

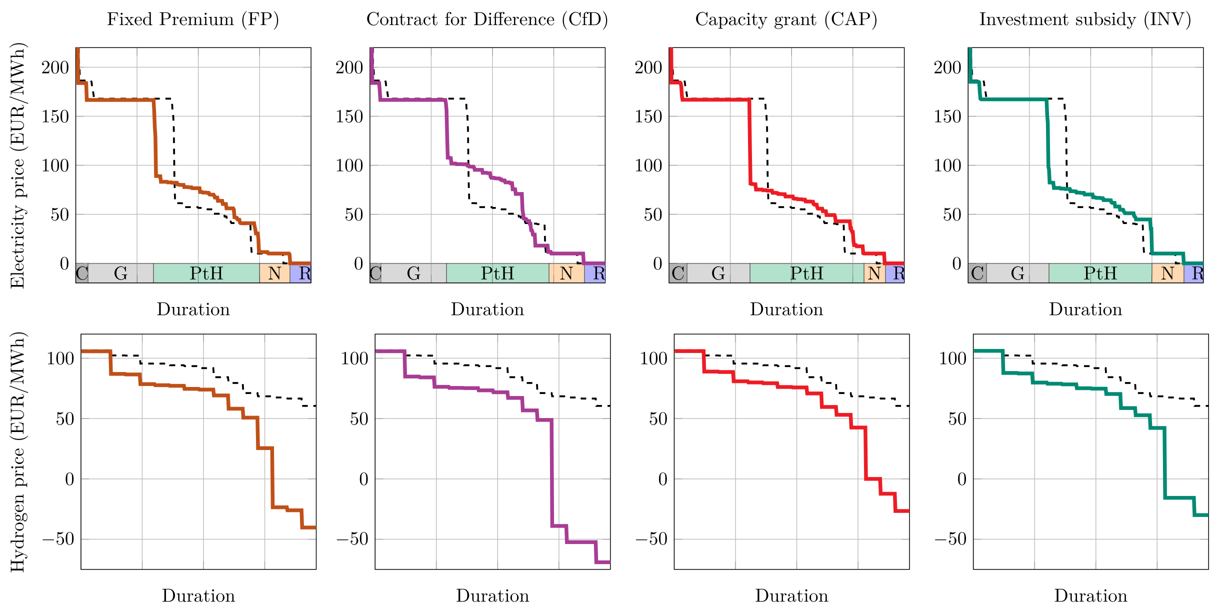


Fig. 5. Price duration curves of electricity (top) and hydrogen (bottom) in 2031 for the four considered support policies, compared to the price duration curve when no subsidies are applied (dotted line). The price-setting technology in the electricity market is either coal or OCGT (C), CCGT (G), power-to-hydrogen (PtH), nuclear (N) or renewable energy sources (R).

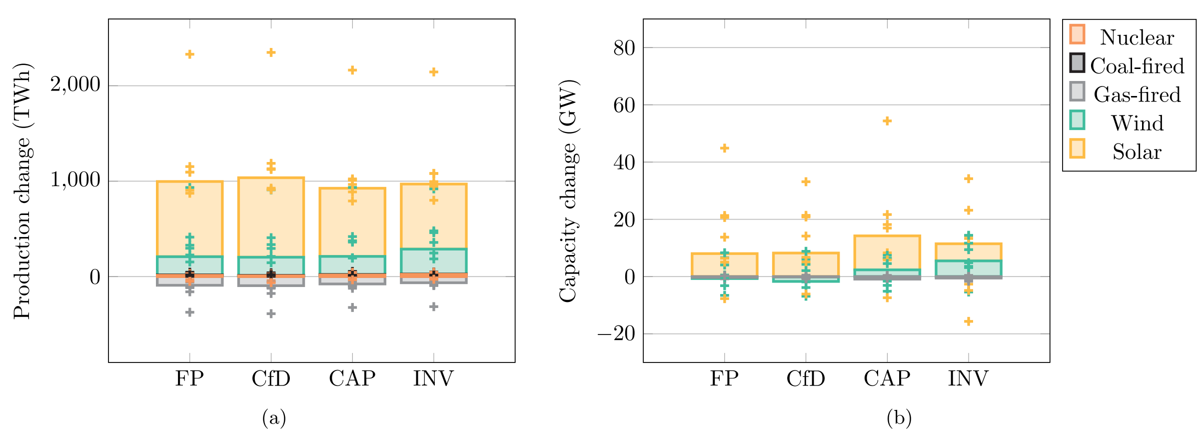


Fig. 6. Impact of fixed premium (FP), contract for difference (CfD), capacity grant (CG), and investment subsidy (INV) on (a) cumulative electricity production until 2040 by source and (b) cumulative capacity investment in the power sector until 2040, compared to no target. For the reference case (bars) and the sensitivities (crosses).

From the changes in investment decisions can be noted that these capacity changes are relatively small, hence the change in electricity production originates primarily from a decrease in curtailment (Fig. 6).

4.5. Influence on emission trading system

Subsidising hydrogen accelerates emission reductions in the power sector, which frees up emission budget for industry and hydrogen sector, hence decreasing carbon prices. This is because subsidising P-t-H makes RES a more attractive investment and lowers emissions in the power sector, but postponing abatement in the industrial sector (Fig. 7). The magnitude of this interaction is limited ($\leq$ 150 Mt CO_2, in all sensitivities), and for a target of 150 Mt H_2, prices do not decrease by more than 5 EUR/tCO_2 (in 2030). Hence, no significant temporal distortion to emission abatement was observed.

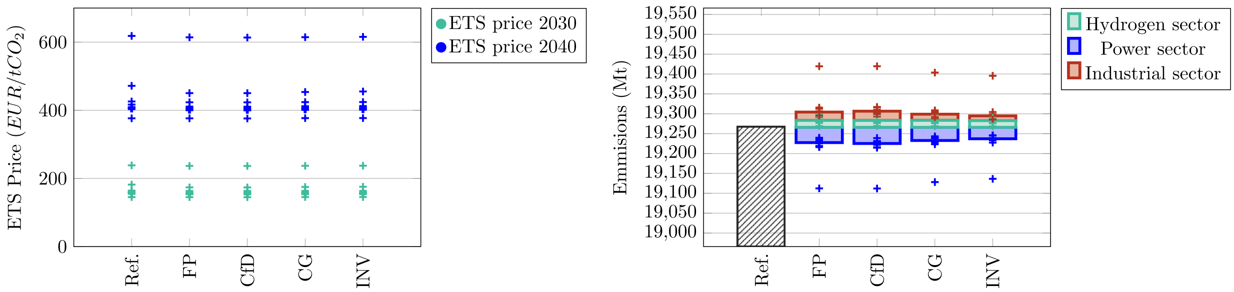
Depending on the sensitivity, an increase in emissions of 2–32 Mt CO_2 was found in the hydrogen sector. The interaction between P-t-H and renewable investment, which frees up carbon budget in the power sector, is stronger than the emission reduction due to increased P-t-H production. The freed-up carbon budget is used to keep using SMR for longer instead of SMR-CCS.

4.6. Performance according to total system cost

We evaluated the performance of the different mechanisms according to total system cost, which encompasses all investment costs, the exogenous operational costs (e.g., fossil fuel prices), and the quadratic hydrogen import and emission abatement costs.

When support instruments are applied that stimulate hydrogen production through one particular technology that is not necessarily cost-optimal, in this case power-to-hydrogen, it is inevitable that total system costs increase.[12] The increase in total system cost of support policies is driven both by the additional investment cost in the hydrogen sector and by an increase in the power sector (Fig. 8). For CAP and INV, the increase in system cost in the power system is lower compared to production-based subsidies for most sensitivities. Hence, the capacity and investment-based instruments can obtain the same hydrogen production via P-t-H at a lower cost than the production-based instruments (FP and H-CfD) but realise more capacity investment. Note that costs in

[12] Since the benefits of addressing the externalities are not captured by the model.



(a) (b)

Fig. 7. (a) Cumulative emissions of the hydrogen, power and industrial sector in the reference case (b) Impact of FP, CfD, CAP and INV on emissions in the considered sectors. For the reference case (bars) and the sensitivities (crosses).

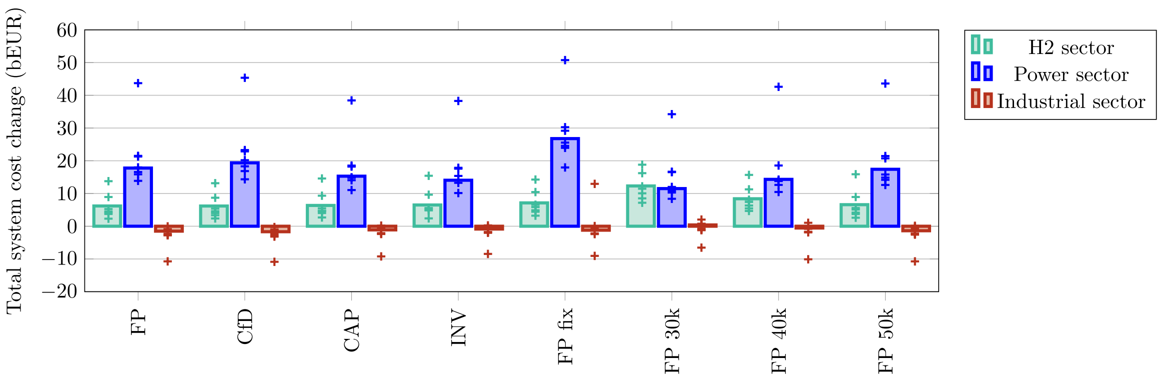


Fig. 8. System cost increase with respect to the no subsidy case for each sensitivity, broken down by sector for various fixed premium variants (FP, FP fix, etc.), contract for difference (CfD), capacity- (CAP) or investment- (INV) subsidy. The reference case is indicated in bars and the sensitivities by the crosses.

the industrial sector decreases for most support instruments, as detailed in Section 4.5.

The additional constraint imposed by the FP-fix variant – a 15 Mt target for each year from 2031 to 2040 rather than a cumulative target of 150 Mt – increases system costs in the power sector due to the imposed production profile, which necessitates additional renewable investment (Fig. 8). The variants that safegaurd against over-subsidisation using limits on the support duration (FP 30k, FP 40k and FP 50k) lead to additional P-t-H capacity investments and hence higher hydrogen sector costs. The stricter the limit, the stronger the incentive to install more P-t-H capacity, and hence the higher the cost increase in the hydrogen sector.

Table 5 shows an overview of the total increase in system costs (%) compared to no subsidy for each sensitivity. Values are coloured based on how they compare against other policies in the same sensitivity. Capacity-based instruments outperform production-based instruments, this implies that the operational inefficiencies that fixed premiums cause trigger higher increases in costs than attracting additional capacity, which is often referred to as a disadvantage of capacity-based instruments. The increase in total system cost due to additional PtH capacity is damped by a decrease in costs in the power sector, where curtailment can be lowered. Therefore lower RES investments are needed to meet a certain hydrogen production volume and the overall increase in capacity-based mechanisms costs remains limited. When comparing FP and H-CfD, it becomes apparent that FP outperforms H-CfD. Under the H-CfD mechanism there are more periods in which the subsidy level is high enough to influence the dispatch decision in the hydrogen market, causing operational inefficiencies and thus increasing cost. Because the H-CfD payout will be higher at low hydrogen prices, there are simply more instances where it influences dispatch decisions. When the H-CfD payout is low, hydrogen prices are high and typically not set by P-t-H, so in those instances neither the FP nor H-CfD shows inefficient dispatch.

5. Discussion

5.1. Limitations and areas for future work

This paper utilises a state-of-the-art partial-equilibrium model that surpasses the complexity of comparable studies in the literature (Roach and Meeus, 2023; Özdemir et al., 2020), yet it is also limited by computational complexity and data availability. We emphasise that our reference case is not a projection, but is contingent on evolving factors such as investment costs, carbon prices, and fuel costs.[13] This does not undermine our findings however, as the results are primarily driven by the type of hydrogen source (blue, grey, or import) that green hydrogen substitutes, and we carefully considered sensitivities for each scenario.

Our stylised approach considering a single hydrogen and electricity price per time step allows us to maintain interpretability and reveal the fundamental interactions between actors, markets, and instruments. More complex models could, e.g., introduce geographical details of hydrogen and electricity markets, this would, e.g., enable an examination of distributional effects among EU member states.

As detailed in Section 2.3, economic justifications for hydrogen subsidisation can potentially be rooted in spillover effects. Incorporating endogenous learning into the model could provide insight into how learning effects influence investment decisions and cost trajectories over time. Learning and spillover effects in the manufacturing of components are well described in the literature (Yelle, 1979; Wright, 1936) and are expected to apply to P-t-H components, as well as the operation and maintenance of P-t-H facilities (Luo and Su, 2022). At this stage, it is, however, unclear whether the learning effects that are

[13] Especially our investment cost assumptions of electrolysers based on IEA (2022), turn out to be quite optimistic compared to more recent studies (IEA, 2023; Krishnan et al., 2023).

Table 5
Overview of the total system cost increase (%) with respect to no subsidy for each sensitivity.

	FP	CfD	CAP	INV	FP 30k	FP 40k	FP 50k	FP fix
Ref	0.89%	0.94%	0.81%	0.78%	0.96%	0.88%	0.89%	1.29%
Low natural gas price	1.51%	1.55%	1.39%	1.42%	1.64%	1.56%	1.50%	1.84%
Expensive import	0.75%	0.78%	0.72%	0.71%	0.88%	0.82%	0.75%	1.12%
No buildout limits	0.74%	0.80%	0.66%	0.70%	0.82%	0.72%	0.73%	1.14%
High PtH buildout	0.95%	1.01%	0.86%	0.85%	1.06%	0.98%	0.94%	1.32%
Expensive peak PtH	1.11%	1.17%	1.00%	1.00%	1.27%	0.97%	1.11%	1.52%
Expensive base PtH	1.22%	1.28%	1.14%	1.12%	1.20%	1.16%	1.18%	1.55%
Low RES buildout	0.62%	0.62%	0.52%	0.56%	0.59%	0.61%	0.59%	1.45%

used to justify hydrogen subsidisation are dependent on the quantity of hydrogen production or are concentrated in economies of scale in the manufacturing of P-t-H components. Moreover, learning in only expected to play a significant role in the cost of the stacks, not the balance of plant (Krishnan et al., 2023). Therefore, it is difficult to assess which instruments will optimally advance learning. What is clear is that capacity-based mechanisms and investment subsidies attract more capacity investments and quantity-based instruments realise more hydrogen production.

Additionally, future research could explore the performance of different support mechanisms under uncertainty, as many of these mechanisms also aim to reduce risk for investors. Evaluating their effectiveness in mitigating risk and their impact on investment behaviour under uncertain market conditions would be valuable, but was out of scope of this paper.

5.2. Recommendations for future support policies

The two most prominent mechanisms to date, the US Inflation Reduction Act and the EU Hydrogen Bank, employ production-based hydrogen support. Awarding support via an auction based on capacity seems overlooked–yet our analysis shows it can be a cost-effective option. Similarly to quantity-based mechanisms, they achieve additional hydrogen production, given adequate RES availability and appropriate short-term market prices, without distorting the operation of P-t-H facilities. We recommend considering ranking bids in auction-based support schemes based on the support needed per hydrogen output capacity [$\mathrm{EUR/kg\,H_2\,h^{-1}}$] rather than hydrogen production [$\mathrm{EUR/kg\,H_2}$].

Limiting the support duration to safeguard against over-subsidisation could increase overall costs and should be implemented with care. The benefits of such provisions that protect against inefficient government spending should be balanced against the reduction in efficiency. However, we acknowledge that uncertainty was not considered in this paper and hence the benefits of such provisions are not captured. Similarly, the obligation to produce and deliver equal quantities of hydrogen each year might yield benefits for offtakers but increases costs to society.

From our analysis of H-CfDs it became apparent that a simple FP outperforms the more complex H-CfDs. The efficiency advantage that CfDs offer in RES support is less pronounced in the hydrogen market, where price fluctuations are not expected to be as volatile as in electricity markets. The benefits of risk-mitigation that H-CfDs likely bring – which we did not analyse – should be traded off against the inefficiencies that the mechanism has.

6. Conclusion

We investigated the impact of hydrogen support mechanisms using a long-term equilibrium model that captures the interactions between hydrogen, electricity and emission markets. We compared capacity-based and production-based mechanisms which are both applied in practice.

The results confirm that capacity-based instruments tend to have a technology selection bias, and production-based instruments distort operational decisions. We found that for the subsidy levels in our case study (0.62–1.44 EUR/kg H_2), inefficiencies in the electricity market remained limited but in the hydrogen market operational distortions were observed. Although the capacity-based mechanisms (CAP and INV) did attract more capacity investments, the cost associated with those investments remained limited due to the reduced curtailment of renewables. This leads us to conclude that, in our case, capacity-based support is the preferred mechanism to promote renewable hydrogen in a cost-effective manner.

CRediT authorship contribution statement

Alexander Hoogsteyn: Writing – original draft, Methodology, Formal analysis, Conceptualization. **Jelle Meus:** Writing – review & editing, Conceptualization. **Kenneth Bruninx:** Writing – review & editing, Methodology, Conceptualization. **Erik Delarue:** Writing – review & editing, Supervision.

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.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.eneco.2024.108042.

Data availability

The output data required to reproduce the above findings are available to download from https://github.com/AlexanderHoogsteyn/EU-ETS-H2-support-instruments of the used Julia implementation of the optimisation models.

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