School of Policy
& Global Affairs

www.city.ac.uk

Is Power-to-Gas Always Beneficial? The Implications of Ownership Structure

Department of Economics♣
Discussion Paper Series No. 23/01

Camillea Megy
Université Paris-Saclay

Olivier Massol*
IFP Energies Nouvelles &
City, University of London

♣ The departmental editor for the discussion paper series was Dr. Orkun Saka and this paper was internally reviewed by Prof. Albert Banal-Estañol.

* Corresponding author address: Department of Economics, City, University of London, Northampton Square, London EC1V 0HB, UK. Email: olivier.massol@ifpen.fr.

Is Power-to-Gas always beneficial?
The implications of ownership structure

MEGY Camille[a,b,c,*], MASSOL Olivier[b,c,a,d]

[a] *Université Paris-Saclay, CentraleSupélec, Industrial Engineering Research Department, 3 rue Joliot-Curie, 91190 Gif-Sur-Yvette, France*

[b] *IFP Energies nouvelles, 1-4 avenue de Bois Préau, 92852 Rueil-Malmaison, France*

[c] *IFP School, 228-232 avenue Napoléon Bonaparte, 92852 Rueil-Malmaison, France*

[d] *City, University of London, Department of Economics, Northampton Square, London, EC1V 0AJ, UK*

Abstract

Power-to-gas (PtG), a technology that converts electricity into hydrogen, is expected to become a core component of future low-carbon energy systems. While its economics and performance as a sector coupling technique have been well studied in the context of perfectly competitive energy markets, the distortions caused by the presence of large strategic players with a multi-market presence have received little attention. In this paper, we examine them by specifying a partial equilibrium model that provides a stylized representation of the interactions among the natural gas, electricity, and hydrogen markets. Using that model, we compare several possible ownership organizations for PtG to investigate how imperfect competition affects its operations. Evidence gained from these market simulations show that the effects of PtG vary with the multi-market profile of its operator. Producers of fossil-based hydrogen tend to make little use of PtG, whereas renewable power producers use it more to increase the electricity prices. Although PtG operations are profitable and can be welfare-enhancing, the social gain is either very tiny or negative when PtG is strategically operated in conjunction with variable renewable generation. In that case, PtG also raises environmental concerns as it stimulates the use of polluting thermoelectric generation.

Keywords: *Power-to-Gas, Sector coupling, Hydrogen, Renewable energy sources, Multi-market oligopoly, Mixed Complementarity Problem*

Acknowledgments and fundings: We thank participants at the 2021 TransAtlantic Infraday, the 32[nd] EURO, the 2022 INFORMS Annual Meeting, the University of Maryland, and the 2022 FAEE workshop for useful remarks. We are also indebted to Wale Arowolo, Ange Blanchard, Vincent Bertrand, Steven Gabriel, Alexis Lebeau, Sebastien Lepaul, and Yannick Perez for insightful suggestions. The remaining errors are, of course, our responsibility. Camille Mégy gratefully acknowledges research funding from the Chair "The Economics of Gas." The views expressed herein are those of the authors and should not be construed to reflect the opinions of their affiliations.

*Corresponding author. E-mail address: camille.megy@centralesupelec.fr

1. Introduction

The prophecy of a "hydrogen economy," according to which that energy carrier becomes a pervasive component of modern societies, dates back from the 1970s (Bockris, 1972) when hydrogen was presented as a possible response to the oil shocks. Nowadays, hydrogen is heralded as a critical technological solution to support the deep decarbonization of our economies (Moliner et al., 2016; European Commission, 2018). This vision presupposes a profound transformation in the way hydrogen is generated and consumed. At present, hydrogen is mainly produced from natural gas through steam methane reforming (SMR) whereas a substantial share of future hydrogen production is expected to emanate from electricity using the electrolysis of water, a technology called Power-to-Gas (PtG) or Power-to-Hydrogen (Seck et al., 2022). From an energy perspective, the large-scale deployment of PtG is expected to have major implications. First, as hydrogen is a seasonally storable form of energy, PtG can provide the temporal flexibility needed for the reliable operation of future low-carbon power systems where generation will be dominated by variable renewable electricity sources (van Leeuwen and Machiel, 2018). Second, hydrogen produced from renewable energy can provide a zero-carbon substitute for coal, oil, natural gas, and SMR-based hydrogen in uses that can hardly be met by electricity, thereby improving energy security by lowering the dependency upon imported fossil fuels.

Against this background, PtG and hydrogen are currently experiencing global hype,[1] and many pilot projects are now being developed all around the world (Chehade et al., 2019). Governments and public authorities are actively preparing dedicated policy packages to attract investment in demonstration projects, foster R&D developments, develop supporting infrastructures, clarify the sector's regulatory framework, and more broadly favor the emergence of a domestic hydrogen industry based on PtG. A non-exhaustive list of these ambitious policy initiatives surely includes: the US landmark Inflation Reduction Act of 2022 (U.S. Congress, 2022), the EU's plan for a green transition (European Commission, 2021b), and Japan's Green Growth Strategy announced in 2020 (METI, 2020).

[1] See *e.g.*, "*Hydrogen hype is rising again—will this time be different?*" The Economist, Nov. 14, 2022.

Notwithstanding the significance of these policy developments, two important issues pertaining to the sector's organization can hardly be overlooked when examining the economics of PtG. First, PtG *de facto* represents a sector coupling technology that enables stronger and more frequent interactions between three previously largely separated industries: hydrogen, natural gas, and electricity. By consequence, as already pointed out in Roach and Meeus (2020) and Li and Mulder (2021), the effectiveness of PtG as a decarbonization technology cannot be assessed in isolation from these other energy sources. Second, PtG is a capital-intensive asset that will most likely be operated by large firms capable of exerting olipolistic control on adjacent markets, including natural gas,[2] electricity,[3] or industrial gases (ERT, 2021). As usual with imperfectly competitive markets, considerations pertaining to the agents' strategic behaviors and the possible exertion of market power can have a major impact on the market outcomes, especially in the short run if the price elasticity of the demand is small as in the cases of electricity or gas. By jointly enabling sector coupling (and thus multi-market interactions) and providing previously specialized oligopolies with the possibility to engage in multi-market operations, the rise of PtG is likely to yield a complete reconfiguration of the market outcomes as well as the firms' conduct and performance.

The purpose of this paper is to clarify the future industrial organization of PtG by examining the degree to which asset ownership considerations influence the market outcomes in the power, gas, and hydrogen markets. In other words, this paper aims at verifying whether one should care about the multi-market activities of the firm that owns and operates the PtG assets. The earlier theoretical literature in industrial organization shows that multi-market competition can affect firms' optimal choices and market equilibria (Metin and Dimitriadis, 2015). For instance, in a two-market system, a firm's decisions in one market can change its production cost in the second one and thus modify the reactions of its competitors (Bulow et al., 1985). This effect typically explains why ownership considerations matter in oligopoly-controlled industries (see *e.g.*, Sioshansi (2010) and Sioshansi (2014) that examine how the ownership structures retained for electricity storage affect the

[2] We refer to Egging et al. (2008), Holz et al. (2008) and Abada et al. (2013) for discussions on the oligopolistic nature of that industry.

[3] A rich literature has documented the presence of imperfect competition in power generation (see, *e.g.*, Green and Newbery (1992), Bushnell (2003), Pineau et al. (2011)).

market outcomes). Yet, the insights gained from that literature are derived from stylized analytical models. Given the complex nature of the intermarket (and possibly intertemporal) effects at hand, a more detailed representation can usefully enrich the analysis of the market effects of PtG.

To investigate how PtG ownership affects its operations, we develop a partial equilibrium model representing the production, consumption, energy conversion, and storage decisions in the power, hydrogen, and natural gas industries. This model captures the imperfect competition prevailing in these industries using a Nash-Cournot paradigm. Technically, the model is specified as an instance of a deterministic multi-period, non-cooperative game that is calibrated for a one-year planning horizon and solved numerically to determine the players' optimal infra-annual decisions. Using this model, we conduct a series of simulations under markedly different ownership structures for PtG assets and compare the results to quantify the effects of PtG ownership on the firms' behaviors and market outcomes. Overall, we believe that this modeling framework can provide valuable insights to energy scholars, practitioners, and policymakers interested in the economics of PtG.

Our analysis highlights that, in the case of imperfectly competitive power, gas, and hydrogen markets, the ownership structure chosen for PtG significantly impacts the equilibrium outcomes. Regarding PtG operations, we show that producers of fossil-based hydrogen tend to make little use of PtG, whereas renewable power producers use it more to increase the electricity prices. From a social perspective, although PtG operations are profitable and can be welfare-enhancing, the social gain is either very tiny or negative when PtG is strategically operated jointly with variable renewable generation. Finally, our results show that this latter case is the only one in which the PtG owner can recoup its PtG investment expenditures. However, in that case, PtG also raises environmental concerns as it stimulates the use of polluting thermoelectric generation.

A rapidly growing literature in energy engineering has recently emerged to investigate the insertion of PtG within future energy systems and its performance as a source of flexibility (Blanco and Faaij, 2018). Many of these contributions typically rely on numerical simulations conducted with a large energy system model that incorporates a detailed representation of the installed energy technologies. These simulation results provide insights on the operations of PtG and its cost-effectiveness relative to other sources of flexibility. For instance, the operational model in Vandewalle et al. (2015) jointly treats the gas, electricity, and CO_2 sector as a single unified system and determines its least-cost operations. The authors demonstrate that PtG lessens gas price pressure and energy curtailment and decreases the need for CO_2 storage. Qadrdan et al. (2015) use a combined gas and electricity optimization model to study the integration of PtG within Great Britain's energy infrastructures. Their results show that the integration of PtG can reduce wind curtailment and operational costs. By nature, that literature emphasizes a meticulous description of the technical constraints affecting system operations (*e.g.*, the effects of unit-commitment constraints or network considerations). It generally concentrates on the interactions between gas and power but has largely overlooked the interactions with the hydrogen market. A notable exception is the analysis of the future Dutch energy system in Koirala et al. (2021). The results document the interweaving of the electricity, hydrogen, and methane markets and stress the need to jointly model them to adequately capture the short-term price and volume interactions between these three energies. Our setting also jointly considers these three markets.

From a methodological perspective, these engineering contributions typically involve the solution to a cost-minimization problem. By nature, this approach is "top-down" as it implicitly presumes that a single decision-maker exerts control over all components of the energy system under scrutiny. Although optimization represents a powerful modeling technique, it is poorly adapted to represent industries with a concentrated market structure where firms can conceivably exert market power (Murphy et al., 2016). In such cases, the strategic interactions among the firms and their effects on the prices and volumes can hardly be overlooked. For that reason, another modeling approach has gained momentum in energy economics that explore such situations: Mixed Complementarity Problem (MCP).[4] By construction, MCPs are adapted to compute a Nash equilibrium because they

[4]MCPs have been widely applied to investigate: the impacts of CO_2 regulation on electricity prices and power investments (Fan et al., 2010) or the effects of strategic behavior and imperfect competition in power generation (Bushnell, 2003; Pineau et al., 2011; Virasjoki et al., 2016; Višković et al., 2017), storage operations (Schill and

allow for a direct representation of the specific optimization problem faced by each agent and their interactions (Gabriel et al., 2013). Compared with optimization, MCPs thus provide an enriched representation of the strategic interactions among agents but their implementation also necessitates simpler descriptions of the energy system. For example, most of the MCP models used in energy economics overlook nonlinearities and indivisibilities to preserve computational tractability.

So far, only a handful of contributions have applied the MCP modeling approach to investigate the market effects of PtG. Roach and Meeus (2020) consider an equilibrium model of the electricity and gas markets coupled by PtG. They investigate the effects of PtG investment decisions on price and welfare and find that the electricity and gas sectors have aligned incentives to engage in PtG. Li and Mulder (2021) develop a short-term equilibrium model of an integrated electric and hydrogen market to study the impact of hydrogen demand on the flexibility services provided by PtG. They show that PtG reduces electricity price volatility but that hydrogen demand lessens this effect. Finally, Lynch et al. (2019) focus on the power industry and investigate the portfolio effects of investing in PtG. They highlight that even if PtG is non-profitable, producers with renewable production in their portfolio are incentivized to invest in it as PtG increases power demand during periods of low net demand and thus drives up electricity prices. To the best of our knowledge, the oligopolistic nature of the agents operating PtG has so far never been investigated. The MCP model in the present paper contributes to that burgeoning literature by offering, for the first time, a stylized representation that captures the effects of PtG as a sector coupling technology affecting three markets, namely power, natural gas, and hydrogen, under a Cournot olipolistic framework.

Our paper is organized as follows. We present our modeling of the electricity, gas, and hydrogen markets and the optimization problems of the different agents in Section 2. Section 3 provides data, and results are detailed in Section 4. Finally, the last section offers a summary and some concluding remarks.

Kemfert, 2011), and the international trade of natural resources, including natural gas (Egging et al., 2008; Abada et al., 2013), crude oil (Huppmann and Holz, 2012), helium (Massol and Rifaat, 2018), and steam coal (Haftendorn and Holz, 2010).

2. Methodology

2.1. Model overview

The present analysis is based on a partial equilibrium model that applies principles from game theory and optimization to simulate the interactions between the markets for power, natural gas, and hydrogen. The model is formulated as a deterministic, discrete-time, finite-horizon oligopoly model that explicitly takes into account the imperfectly competitive structures prevailing in these three sectors. By construction, the model captures the strategic interactions between the different types of oligopolistic players operating in these industries.

Our modeling framework focuses on the operations of assets with exogenously predetermined capacities and considers a one-year time horizon to account for seasonal variations in energy demand and supply. The model thus conveys a stylized representation that overlooks investment considerations. It also overlooks spatial considerations and the role of energy transportation infrastructures.

All individual suppliers are depicted as profit-maximizers under specific constraints, with a distinctive revenue and cost structure for each supplier type. The agents' behaviors and strategy sets are further detailed in the next subsection. For the moment, we simply stress that the model includes Cournot players capable of exerting market power by withholding supplies to force up prices for larger profits. As we clarify in the next subsection, the multi-markets agents with vertically related operations can also exert market power on the buyer side by withholding purchases in order to obtain lower input prices.

Figure 1 provides a compact overview of our baseline scenario labeled "*NoPtG*" that conveys a generic representation of three markets and different market participants. In each sector, the aggregate demand emanating from end-users is determined by a linear demand function. Regarding electricity, power generation is operated by a group of Cournot firms and a competitive fringe. For simplicity, we only retain two generation technologies: either intermittent renewable sources (Variable Renewable Electricity, hereafter VRE) or dispatchable generation in the form of Combined Cycle Gas Turbine (CCGT). Regarding natural gas supply, we consider a duopoly of midstream firms (a.k.a., shippers). The first is a pure player that operates solely in the gas market, whereas the second is a multi-market firm that also converts methane into hydrogen through SMR. Our setting includes price-taking gas and hydrogen storage operators capable of performing inter-temporal arbitrages whenever these are profitable.

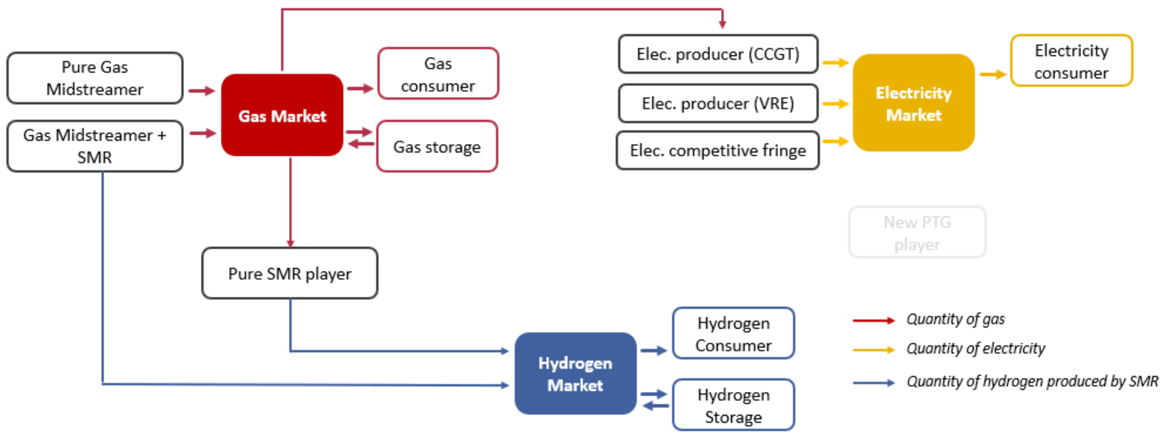

Figure 1: The three markets and the different market participants under the baseline scenario "*NoPtG*"

Under the baseline scenario "*NoPtG*," no PtG conversion is installed and hydrogen is entirely produced from natural gas through SMR conversion. Hydrogen supply thus emanates from either an independent SMR player or a natural gas midstreamer equipped with SMR conversion capabilities.[5]

To explore the effects of PtG, we introduce a conversion technology within that generic representation. We consider a series of alternative scenarios that represent various PtG-ownership arrangements that can emerge (see Table 1). The scenario labeled "*H-NewProd*" posits a "pure player" business model whereby PtG conversion is operated by an independent specialized firm. Under the scenario "*E-CCGT*" (respectively "*E-VRE*"), PtG is owned by the multi-market firm that also generates electricity using a dispatchable technology (respectively intermittent renewable sources). Similarly, in two scenarios "*G-Gas*" and "*G-Gas+SMR*," PtG is respectively operated by the natural gas midstreamer or the gas

[5]We focus on PtG and SMR as they are the most mature and widely deployed technologies in the current prospective scenarios (World Energy Council, 2021). Furthermore, PtG as a storage solution for the electric system (power-to-gas-to-power) is not considered. Currently having a meager energy yield, this use of PtG could, however, be included in long-term studies.

midstreamer that also produces hydrogen through SMR. Lastly, we also consider "*H-SMR*" to study the case of an "industrial gas" firm that also produces hydrogen from natural gas using SMR conversion.

Table 1: Seven scenarios for PtG ownership

Scenario	Description of the business model posited for the PtG operator
NoPtG	Baseline scenario with no PtG conversion capabilities
H-NewProd	Independent firm: PtG as a pure player
H-SMR	Multi-market firm: a SMR-based hydrogen producer with PtG conversion
G-Gas	Multi-market firm: a gas midstreamer with PtG conversion
G-Gas+SMR	Multi-market firm: a gas midstreamer with both PtG and SMR conversion
E-CCGT	Multi-market firm: a thermal generator with PtG conversion
E-VRE	Multi-market firm: a VRE generator with PtG conversion

These alternative ownership scenarios are depicted in §Appendix A. These scenarios together provide a complete coverage of the various business models that can be envisioned for the provision of PtG conversion, namely that of an independent "pure player" and the ones that involve a multi-market strategy combining PtG with an active participation in one (or two) other energy market(s), namely power, natural gas, or hydrogen.

2.2. *Formulation of the model*

The model formulation enables us to take both non-strategic and strategic players into account. Indeed, for each of the three markets (designated in this paragraph by the generic letter k), each player p considers the following price function π^k when solving its optimization problem:

$$\pi^k = (1 - \delta_p^k).\pi^{k^*} + \delta_p^k.\Pi^k(.)$$

The binary parameter δ_p^k is exogenously determined for each market k and player p. It encodes our behavioral assumptions as it indicates for market k whether the player p has a perfectly competitive behavior ($\delta_p^k = 0$) or behaves strategically by accounting for the effects of its decisions on the prevailing market price ($\delta_p^k = 1$). In the first case, the player is a price-taking firm that naively considers the price variables to be exogenous to its optimization problem ($\pi^k = \pi^{k^*}$ as set by the market clearing equation). In the latter case, the agent considers the inverse demand function $\Pi^k(.)$ emanating from the end-users. If that price is the one charged for the firm's output, that agent can exert oligopolistic market power by withholding supply to increase the overall price. If that price is the one charged for an input used by the firm, the firm can exert oligopsonistic market power by withholding purchases to decrease the price of that input.

We consider a planning horizon of one year with an hourly time resolution to capture the effects of seasonal and weekly variations in energy demand and RES supplies. Consistent with the institutional organizations governing the wholesale markets for gas and power, we assume different clearing frequencies. We retain an hourly clearing for the electricity market whereas the hydrogen and gas markets are cleared daily. In the following, we let d denote a day, and h an hour. To preserve computational tractability, we consider a clustering of these time periods into representative days and hours that preserve the intra-annual variations in supply and demand. Each representative d (respectively, hour h) is weighted with a coefficient w_d (respectively, w_h) that reflects the occurrence of that particular period within the year (see Appendix C.1).

In the remainder of this subsection, we present the optimization problems of the individual players and specify the market clearing conditions for the three energies. Variable and parameter names are introduced progressively in the following paragraphs. For each problem, we let the letter λ in brackets denote the dual variable associated with each constraint.

2.2.1. Electricity

Electricity producers

Each electricity producer p is modeled as a profit-maximizing firm that decides $q^E_{p,x,d,h}$ the hourly quantity electricity it produces using each generation technology x in a portfolio of $\mathcal{X}$ generation sources. The firm also decides the hourly quantity of hydrogen $q^H_{p,PtG,d,h}$ produced from electricity whenever it operates a PtG conversion asset. That firm's optimization problem is in (1):

$$\underset{\substack{q^E_{p,x,d,h}, q^{E,up}_{p,CCGT,d,h},\\ q^H_{p,PtG,d,h}}}{\text{maximize}} \quad \sum_{d,h} w_d . w_h . \Bigg[\sum_{x \in \mathcal{X}} \left(q^E_{p,x,d,h} . \pi^E_{d,h} - q^E_{p,x,d,h} . C^E_{p,x,d} \right) - q^{E,up}_{p,CCGT,d,h} . C^{E,up}_{CCGT,d} \tag{1a}$$

$$+ q^H_{p,PtG,d,h} . \left(\pi^H_d - \frac{1}{\gamma_{PtG}} . \pi^E_{d,h} \right) \Bigg] \tag{1b}$$

subject to

$$q^E_{p,VRE,d,h} = K^E_{p,VRE} . AV^E_{p,d,h} \qquad \forall d, h, \quad (\lambda^{E,1}_{p,d,h}), \tag{1c}$$

$$q^E_{p,CCGT,d,h} \leq K^E_{p,CCGT} \qquad \forall d, h, \quad (\lambda^{E,2}_{p,d,h}), \tag{1d}$$

$$q^H_{p,PtG,d,h} \leq K^H_{p,PtG} \qquad \forall d, h, \quad (\lambda^{E,3}_{p,d,h}), \tag{1e}$$

$$w_h . q^E_{p,CCGT,d,h} \leq w_{h-1} . q^E_{p,CCGT,d,h-1} + w_h . q^{E,up}_{p,CCGT,d,h} \forall d, h, \quad (\lambda^{E,4}_{p,d,h}), \tag{1f}$$

$$0 \leq q^E_{p,x,d,h}, \quad 0 \leq q^{E,up}_{p,CCGT,d,h}, \quad 0 \leq q^H_{p,PtG,d,h} \qquad \forall d, h, x \tag{1g}$$

The objective function includes the total revenue and total costs associated with its generation decisions (1a), and, whenever producer p is also endowed with a PtG conversion asset, the total revenues and costs related to the sale of hydrogen (1b).

On the cost side, the unit generation costs $C^E_{p,x,d}$ comprise operation and maintenance costs, fuel costs, and costs related to CO_2 emissions. For thermal generation, we also consider the ramp-up costs $C^{E,up}_{CCGT,d}$ of CCGT plants and let the non-negative variable $q^{E,up}_{p,CCGT,d,h}$ denote the net increase in the output of these plants in hour h compared with the output during the preceding hour $h-1$. Regarding the cost of hydrogen production from PtG, we assume that, in the short run, that unit cost is determined solely by the opportunity cost of the electricity purchased for that conversion. We let γ_{PtG} denote the conversion efficiency from electricity to hydrogen.

From a behavioral perspective, the firm's objective function considers the inverse demand functions for power and hydrogen. Hence, we assume that the firm behaves like a strategic player in the sale of electricity and, whenever it controls a PtG asset, also in the sale of hydrogen and in the purchase of power converted into hydrogen.

The firm's decision is subjected to several technological constraints. The amount of renewable electricity generated in each hour is exogeneously determined and given by the resource availability at that time (1c). In that equation, the left-hand side is the product of the renewable capacity $K^E_{p,VRE}$ and the availability factor for renewable energy generation $AV^E_{p,d,h}$ in hour h. For dispatchable thermal generation such as CCGT units, the non-negative amount of electricity generated $q^E_{p,CCGT,d,h}$ is bounded by $K^E_{p,CCGT}$ the installed capacity (1d). Ramp-up constraints (1f) are also considered for CCGT. Finally, the firm's hydrogen production from PtG cannot exceed the installed capacity (1e).

Electricity demand from end-users

We adopt a simplified representation of the demand for electricity emanating from end-users other than PtG assets, namely from uses in the residential, tertiary, and industrial sectors. The hourly aggregate quantity of electricity $D^E_{d,h}$ consumed by these users is determined by the following linear demand function:

$$\forall d, h, \quad D^E_{d,h} = a^E_{d,h} - b^E_{d,h}.{\pi^E_{d,h}}^* \tag{2}$$

where the positive parameters $a^E_{d,h}$ and $b^E_{d,h}$ respectively represent the intercept and the slope of the demand function. These coefficients are time-varying and exogenously determined (see Appendix C.3).

Electricity market clearing conditions

The market-clearing conditions tie the separate power producers' optimization problems to our simplified representation of the demand for electricity. This condition ensures that, in each hour, the total demand for electricity (*i.e.*, the aggregate consumption $D^E_{d,h}$ and the quantity of electricity converted into hydrogen, that is, $\sum_p \frac{q^H_{p,PtG,d,h}}{\gamma_{PtG}}$) is not greater than the aggregate supply, that is, the sum of the producers' generation from all technologies (*i.e.*, $\sum_{p,x} q^E_{p,x,d,h}$). The market clearing condition at hour h ensures balance between supply and demand by adjusting the non-negative price ${\pi^E_{d,h}}^*$ so that supply and demand equilibrate. If electricity production exceeds demand, that price is zero and the surplus electricity is spilled. Formally, this condition writes:

$$\forall d,h, \quad 0 \leq \sum_{p,x} q^{E}_{p,x,d,h} - \Big(D^{E}_{d,h} + \sum_{p} \frac{q^{H}_{p,PtG,d,h}}{\gamma_{PtG}} \Big) \perp {\pi^{E}_{d,h}}^{*} \geq 0 \tag{3}$$

where the $\perp$ operator is used as a compact notation to indicate that one of the two inequalities must be binding (see (Gabriel et al., 2013)).

2.2.2. Natural gas

Gas midstreamers

Each gas midstreamer p seeks to maximize its profit by deciding $q^{G}_{p,d}$ the daily quantity of gas it supplies to the methane market. Whenever that agent is also endowed with PtG or SMR conversion capabilities, it considers an enriched objective function to account for the profits gained from the production and sale of hydrogen. We let $q^{H}_{p,SMR,d}$ (respectively, $q^{H}_{p,PtG,d,h}$) denote the daily (respectively, hourly) quantity of hydrogen produced by that agent using SMR (respectively, PtG). The optimization problem of a gas midstreamer is detailed in (4):

$$\underset{\substack{q^{G}_{p,d}, q^{H}_{p,SMR,d}, \\ q^{H}_{p,PtG,d,h}}}{\text{maximize}} \quad \sum_{d} w_{d} \cdot \Big[q^{G}_{p,d} \cdot \pi^{G}_{d} - q^{G}_{p,d} \cdot \Big(C^{G}_{inter} + C^{G}_{slope} \cdot q^{G}_{p,d} \Big) \Big] \tag{4a}$$

$$+ \sum_{d} w_{d} \cdot \Big[q^{H}_{p,SMR,d} \cdot \Big(\pi^{H}_{d} - \frac{1}{\gamma_{SMR}} . (\pi^{G}_{d} + C_{CCS}) \Big) \Big] \tag{4b}$$

$$+ \sum_{d,h} w_{d} . w_{h} \cdot \Big[q^{H}_{p,PtG,d,h} \cdot \Big(\pi^{H}_{d} - \frac{1}{\gamma_{PtG}} . {\pi^{E}_{d,h}}^{*} \Big) \Big] \tag{4c}$$

subject to

$$q^{H}_{p,SMR,d} \leq K^{H}_{p,SMR} \qquad \forall d \quad (\lambda^{G,1}_{p,d}), \tag{4d}$$

$$q^{H}_{p,PtG,d,h} \leq K^{H}_{p,PtG} \qquad \forall d,h \quad (\lambda^{G,2}_{p,d,h}), \tag{4e}$$

$$0 \leq q^{G}_{p,d}, \quad 0 \leq q^{H}_{p,SMR,d}, \quad 0 \leq q^{H}_{p,PtG,d,h} \qquad \forall d,h \tag{4f}$$

The objective function accounts for: the profits obtained from the sales of methane in the gas market (4a), the conversion of methane into hydrogen using SMR (4b) or the conversion of electricity into hydrogen using PtG (4c) whenever that agent owns such conversion technologies. In equation (4a), the firm is posited to behave as a strategic player as its total revenue considers the inverse demand function for methane. Following Roach and Meeus (2020), the unit cost of gas is given by a linear function of the firm's sales: $C_{gas}(q^G_{p,d}) = C^G_{inter} + C^G_{slope}.q^G_{p,d}$.

Regarding hydrogen, we assume that, on the selling side, the gas midstreamer can exert market power by withholding its supplies of hydrogen. On the buying side, the gas midstreamer can exert buyer power on the gas it purchases for SMR conversion (see eq. (4b)) but is a price-taking agent when purchasing power for PtG (see the exogenously determined market price for electricity ${\pi^E_{d,h}}^*$ in eq. (4c)). Here, we let γ_{SMR} (respectively, γ_{PtG}) denote the conversion efficiency from gas (respectively, electricity) to hydrogen. In case of SMR conversion, the firm also considers C_{CCS} the unit cost incurred for the Carbon Capture and Storage (CCS) operations.[6] Following Li and Mulder (2021), the CCS cost is:

$$C_{CCS} = \epsilon^{CO_2}.(\theta.c^{CCS} + (1-\theta).\pi^{CO_2}),$$

where ϵ^{CO_2} is the carbon intensity of methane reforming, θ is the fraction of carbon emission being captured and sequestrated using CCS, c^{CCS} is the cost of CCS per ton of carbon, and π^{CO_2} is the exogenously determined price of the carbon used to determine the emission cost of the portion of carbon emissions that are not captured.

In addition, the firm's decisions regarding the production of hydrogen using SMR and PtG must be compatible with the respective capacity constraints (4d–4e).

Gas storage operator

We assume that gas storage operations are decided by a collection of symmetric price-taking firms performing profit-maximizing, inter-temporal arbitrages. We model their aggregate behavior using a representative storage operator that observes the market clearing prices for gas ${\pi^G_d}^*$ and selects the daily aggregate quantities of gas that are injected, withdrawn, and stored ($r^G_{in,d}$, $r^G_{out,d}$ and $u^G_{stor,d}$ respectively). This agent solves the following profit-maximization program:

[6] Similar to the case of power producers, that representation focuses on the short run and thus overlooks the capital expenditures incurred when investing in SMR or PtG plants.

$$\underset{\substack{u^G_{stor,d}, r^G_{in,d},\\ r^G_{out,d}}}{\text{maximize}} \quad \sum_{d \in \mathcal{D}} w_d. \Big[r^G_{out,d}.\pi^{G\,*}_d - r^G_{in,d}.\Big(\pi^{G\,*}_d + C^G_{in}\Big)\Big] \tag{5a}$$

subject to

$$r^G_{in,d} \leq T^G_{in}.K^G_{stor} \qquad \forall d \quad (\lambda^{G,1}_{stor,d}), \tag{5b}$$

$$r^G_{out,d} \leq T^G_{out}.K^G_{stor} \qquad \forall d \quad (\lambda^{G,2}_{stor,d}), \tag{5c}$$

$$u^G_{stor,d} \leq K^G_{stor} \qquad \forall d \quad (\lambda^{G,3}_{stor,d}), \tag{5d}$$

$$u^G_{stor,d} = u^G_{stor,d-1} + w_d.\Big(r^G_{in,d} - r^G_{out,d}\Big) \qquad \forall d \quad (\lambda^{G,4}_{stor,d}), \tag{5e}$$

$$0 \leq r^G_{in,d}, \quad 0 \leq r^G_{out,d}, \quad 0 \leq u^G_{stor,d} \quad \forall d \tag{5f}$$

where, C^G_{in} denotes the unit injection cost. Constraints (5b–5c) state that injection and withdrawal decisions are respectively bounded by the storage capacity (K^G_{stor}) and the maximum injection and withdrawal rates (T^G_{in}, T^G_{out}). Restriction (5d) ensures that the accumulated quantity of gas stored does not exceed the storage capacity. Finally, the state equation (5e) is a balance identity: on each day d, the storage inventory $u^G_{stor,d}$ is equal to inventory level at day $d-1$ plus the quantity of gas injected into the storage minus that withdrawn from the storage. In the simulations, we also impose a boundary condition stipulating that the inventory level at the beginning of the year should equal that at the end of the year.

Gas demand from consumers

We let D^G_d denote the daily consumption of natural gas emanating from all sectors except SMR conversion and thermal power generation. The daily consumption is modeled using the following linear demand function, where a^G_d and b^G_d respectively represent the intercept and the slope coefficients:

$$\forall d, \quad D^G_d = a^G_d - b^G_d.\pi^{G\,*}_d \qquad a^G_d > 0, b^G_d > 0 \tag{6}$$

Gas market clearing condition

The total daily demand for natural gas is the sum of: the consumer demand D^G_d, the total quantity of gas consumed by the power producers that generate electricity using CCGT plants during that day (that is, $\sum_p \sum_{h\in\mathcal{H}} \frac{q^E_{p,CCGT,d,h}}{\gamma_{CCGT}}$), the total quantity of natural gas converted into hydrogen using SMR (*i.e.*, $\sum_p \frac{q^H_{p,SMR,d}}{\gamma_{SMR}}$), and $r^G_{in,d}$ the quantity injected into gas storage. The total daily supply of natural gas includes $\sum_p q^G_{p,d}$ the aggregate supply decided by the gas midstreamers, and $r^G_{out,d}$ the quantity withdrawn from the gas storage. The daily market clearing condition stipulates that the non-negative price $\pi^{G\,*}_d$ is such that the total daily demand equals the total daily supply of natural gas. If natural gas supply exceeds the demand, the price is zero. Formally, this condition is:

$$\forall d, \quad 0 \leq \sum_p q^G_{p,d} - \Big(D^G_d + \sum_p \frac{q^H_{p,SMR,d}}{\gamma_{SMR}} + \sum_p \sum_{h\in\mathcal{H}} \frac{q^E_{p,CCGT,d,h}}{\gamma_{CCGT}}\Big) + \Big(r^G_{out,d} - r^G_{in,d}\Big) \perp \pi^{G\,*}_d \geq 0 \tag{7}$$

2.2.3. Hydrogen

<u>*Hydrogen producers*</u>

We now consider the case of a "pure" hydrogen player p that operates either a PtG or an SMR asset. That firm decides $q^H_{p,PtG,d,h}$ (respectively, $q^H_{p,SMR,d}$) the quantity of hydrogen it produces using PtG (respectively, SMR) and solves the following profit-maximization problem:

$$\underset{q^H_{p,SMR,d},\, q^H_{p,PtG,d,h}}{\text{maximize}} \quad \sum_{d\in\mathcal{D}} w_d \cdot \left[q^H_{p,SMR,d} \cdot \Big(\pi^H_d - \frac{1}{\gamma_{SMR}} . (\pi^{G\,*}_d + C_{CCS}) \Big) \right] \tag{8a}$$

$$+ \sum_{d\in\mathcal{D}, h\in\mathcal{H}} w_d . w_h \cdot \left[q^H_{p,PtG,d,h} \cdot \Big(\pi^H_d - \frac{1}{\gamma_{PtG}} . \pi^{E\,*}_{d,h} \Big) \right] \tag{8b}$$

subject to

$$q^H_{p,SMR,d} \leq K^H_{p,SMR} \qquad \forall d \quad (\lambda^{H,1}_{p,d}), \tag{8c}$$

$$q^H_{p,PtG,d,h} \leq K^H_{p,PtG} \qquad \forall d, h \quad (\lambda^{H,2}_{p,d,h}), \tag{8d}$$

$$0 \leq q^H_{p,SMR,d}, \quad 0 \leq q^H_{p,PtG,d,h} \qquad \forall d, h \tag{8e}$$

The objective function is the sum of the profits obtained from SMR and PtG conversion. We assume the agent behaves strategically in the hydrogen market as it evaluates its total revenue by multiplying its total sales with the price given by the inverse demand function for hydrogen. On the cost side, the agent considers only the cost of its energy purchases and is posited to behave as price-taking firm in the electricity and gas markets. Hence, its purchases of electricity and gas ignores how these decisions affect the market prices of its inputs as that agent considers only the prevailing market prices, ${\pi^E_{d,h}}^*$ and ${\pi^G_d}^*$ respectively. Finally, hydrogen production by SMR and PtG are respectively limited by the installed capacities (8c–8d).

Hydrogen storage operator

Consistent with the institutional organization envisioned in European Commission, Directorate-General for Energy and al. (2021), we model the hydrogen storage decisions using a representative storage operator that behaves as a price-taking firm conducting intertemporal arbitrages. We let $r^H_{in,d}$, $r^H_{out,d}$ and $u^H_{stor,d}$ denote the operator's decisions regarding the daily quantities injected, withdrawn, and stored. The profit-maximization problem of that operator is:

$$\underset{\substack{u^H_{stor,d}, r^H_{in,d},\\ r^H_{out,d}}}{\text{maximize}} \quad \sum_{d \in \mathcal{D}} w_d . \left[r^H_{out,d} . {\pi^H_d}^* - r^H_{in,d} \left({\pi^H_d}^* + C^H_{in} \right) \right] \tag{9a}$$

subject to

$$r^H_{in,d} \leq T^H_{in} . K^H_{stor} \qquad \forall d \quad (\lambda^{H,1}_{stor,d}), \tag{9b}$$

$$r^H_{out,d} \leq T^H_{out} . K^H_{stor} \qquad \forall d \quad (\lambda^{H,2}_{stor,d}), \tag{9c}$$

$$u^H_{stor,d} \leq K^H_{stor} \qquad \forall d \quad (\lambda^{H,3}_{stor,d}), \tag{9d}$$

$$u^H_{stor,d} = u^H_{stor,d-1} + w_d . \left(r^H_{in,d} - r^H_{out,d} \right) \qquad \forall d \quad (\lambda^{H,4}_{stor,d}), \tag{9e}$$

$$0 \leq r^H_{in,d}, \quad 0 \leq r^H_{out,d}, \quad 0 \leq u^H_{stor,d} \quad \forall d \tag{9f}$$

As in the case of gas storage, the decisions of the hydrogen storage operator are subjected to injection, withdrawal, and storage capacity constraints (9b–9d) and the state equation (9e) describes the dynamics of $u^H_{stor,d}$ the daily inventory level over time. Similar to the gas storage, we also impose a boundary condition stipulating that the inventory level at the beginning of the year should equal that at the end of the year.

Hydrogen demand from consumers

We let D^H_d denote the daily final consumption of hydrogen and assume it is determined by a linear demand function:

$$\forall d, \quad D^H_d = a^H_d - b^H_d . {\pi^H_d}^* \qquad a^H_d > 0, b^H_d > 0 \tag{10}$$

where the intercept a_d^H and the slope b_d^H coefficients are exogenously determined.

Hydrogen market clearing condition

Finally, we consider the following market clearing conditions for the hydrogen market. The non-negative price of hydrogen $\pi_d^{H^*}$ ensures a daily balance between total hydrogen demand – that is, final consumption plus the quantity injected into storage – and total hydrogen supply emanating from PtG and SMR production plus storage withdrawal. In case of excess supply, that daily price is zero. Formally, that condition writes:

$$\forall d, \quad 0 \leq \sum_p \left(q^H_{p,SMR,d} + \sum_{h \in \mathcal{H}} w_h . q^H_{p,PtG,d,h} \right) - D^H_d + \left(r^H_{out,d} - r^H_{in,d} \right) \perp \pi_d^{H^*} \geq 0 \quad (11)$$

2.3. Solution strategy and implementation

The model above thus consists of a collection of linearly constrained convex mathematical programming problems that are tied together by the market clearing conditions. These problems are interrelated because the linear or quadratic objective function of each agent is affected by both its actions and that of other agents. We consider, for each market participant, the Karush-Kuhn-Tucker (KKT) conditions that are necessary and sufficient to obtain a solution to that agent's optimization problem. For concision, these KKT conditions are detailed in Appendix B.

Together with the demand equations (2), (6), and (10) and the market-clearing conditions (3), (7), and (11), these KKT conditions form a linear complementarity problem – *i.e.,* a special type of MCP (see Cottle et al. (2009) and Gabriel et al. (2013) for thorough presentations of this problem) – that has a unique solution. By nature, that solution is a vector of individual decisions such that no agent has an incentive to unilaterally deviate from their equilibrium actions, that is, a Nash equilibrium. From a computational perspective, that MCP can be solved efficiently using dedicated solution algorithms such as the PATH solver (Dirkse and Ferris (1995); Ferris and Munson (2000)) used in the application below.

3. Application: Data and model calibration

We calibrate our model to obtain a stylized representation of a future low-carbon energy system. Though this research does not intend to produce a full-fledged replication of a particular energy system, we use the future Dutch energy system for the year 2030 as a reference to obtain a realistic parameterization. Our focus on the Netherlands is motivated by the country's strong interest in the development of hydrogen use for the decarbonization of its economy (IEA, 2021).

Regarding the future power generation mix, the retained installed capacities are consistent with 2030 projections of the EU Reference scenario 2020 (European Commission, 2021a). Our simulations thus consider 53 GW of VRE capacity with an installed CCGT capacity of 12 GW. The hourly availability factors of VRE are based on observed 2019 data from the Renewable Ninja database (Open Power System Data, 2019). The availability of CCGT is set at 85%, in line with the assumptions in IEA (2020).

For power generation, we posit a hypothetical market structure formed by a duopoly of strategic players labeled "E-VRE" and "E-CCGT" completed with a competitive fringe that is treated as a representative price-taking agent. Table 2 presents the individual portfolio of the generation technologies of these firms. "E-CCGT" (respectively, "E-VRE") is a specialized firm with a unique generation technology: it controls half of the installed CCGT (respectively, VRE) capacity. The remaining capacity belongs to the competitive fringe.

Table 2: Generation capacity of each power producer per technology (GW)

	Fringe	E-VRE	E-CCGT
VRE	27	26	-
CCGT	6	-	6

For natural gas, we assume a concentrated market structure based on a Cournot duopoly including a pure gas player labeled "G-Gas," and a multi-market one equipped with SMR conversion capabilities named "G-Gas+SMR."

Regarding hydrogen production from gas, we consider an installed SMR capacity of 10 GW. While this large figure overstates the current Dutch capacity, it presumes the development of foreign supplies of blue hydrogen directed to the Netherlands. From a computational perspective, that figure also prevents corner solutions whereby hydrogen consumption is *de facto* arbitrarily constrained by the posited SMR capacity. Total SMR capacity is equally shared among two producers: the aforementioned multi-market gas midstreamer "G-Gas+SMR" and a pure player labelled "H-SMR."

Finally, we consider an installed capacity of 4 GW for the electrolyzers used for PtG conversion. This figure is in line with the Dutch national ambition for 2030 (en Klimaat, Ministerie van Economische Zaken, 2019). Depending on the scenario under scrutiny, that PtG capacity belongs to either the specialized firm "H-New Prod" or one of the multi-market firms.

For concision, the assumptions regarding the costs and the technical characteristics of the energy technologies (*e.g.*, efficiency data) are presented in Appendix C.2. The calibration of the demand functions is detailed in Appendix C.3. Consistent with the IEA (2020), the market simulations are conducted using two possible values for π_{CO_2} the exogenously determined price of carbon emissions, namely €30 and €90 per tCO_2.

4. Results and discussion

We solve our model for each of the seven PtG ownership scenarios in Table 1 and this section compares the simulation results. It successively examines the effects of PtG on the market outcomes, the social consequences on market participants, and the environmental performance. For the sake of concision, this discussion mainly focuses on the results obtained with a carbon price of €30 per tCO_2. Unless otherwise noted, the results obtained with a larger carbon price are presented in Appendix D as they yield similar findings.

4.1. Overall effects of PtG on supply and demand

We first concentrate on two scenarios: "*NoPtG*" the baseline one that has no PtG, and "*H-NewProd*" that includes an independent PtG operator. That comparison provides insights on how the insertion of PtG conversion capabilities affects the aggregate supply and demand of electricity, gas, and hydrogen.

Tables 3a and 3b report the aggregate annual quantities of electricity, gas, and hydrogen supplied and demanded. Note that, in the hydrogen market, the introduction of PtG leads to a net increase (+1.78 TWh) in total consumption. From a technological perspective, that introduction also triggers a substitution of SMR-based quantities by PtG-based ones since SMR declines by 3.45 TWh whereas PtG supplies attain 5.23 TWh. In the gas market, the lower use of SMR conversion translates into a reduced total demand for that energy. However, as clarified below (see the discussion on prices in §4.3), that demand contraction triggers slightly lower price levels for natural gas which explains the modest increases in the gas consumption figures for power generation (+0.15 TWh to attain 23.49 TWh) or other end-users (+1.02 TWh to attain 247.93 TWh).

Table 3: Annual production and demand by sector under the scenarios "*NoPtG*" and "*H-NewProd*" with $\pi_{CO_2} = 30$ €/tCO$_2$

(a) Annual production (in TWh)

		NoPtG	H-NewProd
Electricity	VRE	87.71	87.71
	CCGT	14.00	14.09
Gas		297.79	293.20
Hydrogen	SMR	16.52	13.07
	PtG	0	5.23

(b) Annual demand (in TWh)

		NoPtG	H-NewProd
Electricity	Consumers	100.46	94.33
	Elec $\rightarrow$ H_2	0	7.47
	Curtailment	1.25	0
Gas	Consumers	246.91	247.93
	Gas $\rightarrow$ Elec	23.34	23.49
	Gas $\rightarrow$ H_2	27.53	21.79
Hydrogen		16.52	18.30

In the electricity market, a quantity of 1.25 TWh of electricity is spilled under the baseline scenario. In contrast, there is no curtailment under the scenario "*H-NewProd*." A closer look at the infra-annual simulation results obtained under the baseline scenario indicates that this spillage occurs in periods when VRE production exceeds the total demand for electricity. The insertion of PtG thus eliminates the waste of VRE generation demonstrating that PtG fulfills its role as a source of power flexibility. On the supply-side, total generation is slightly larger when PtG is available (+0.09 TWh). On the demand-side, the extra-consumption associated with hydrogen conversion (+7.47 TWh) is larger than the spillage of VRE resources. Hence, the PtG operations are not restricted to periods when VRE production exceeds the end-users' consumption of electricity. Concomitantly, we observe a reconfiguration of the structure of electricity demand. PtG insertion results in a slightly larger total electricity demand (*i.e.*, 101.8 TWh compared with 100.46 TWh) that, in turns, yields increased power prices (see the discussion in §4.3). These higher prices explain the contracted volumes demanded by other end-users (-6.13 TWh to reach 94.33 TWh). In other words, the implementation of PtG increases power production but decreases the amount of electricity available to the other end-users of that energy.

These findings are not specific to the scenario "*H-NewProd.*" Compared to the baseline scenario, the five other scenarios also include PtG conversion capabilities and thus exhibit similar changes in the aggregate supplies and demands of electricity, gas, and hydrogen.

4.2. PtG utilization

We now examine the use of that conversion asset. As a preliminary analysis, we examined the hourly-cleared electricity market and we observed that, in all scenarios but "*E-VRE*," PtG conversion is never used during hours with positive CCGT outputs, indicating that the cost of producing hydrogen from thermal electricity is too high to make PtG conversion attractive against SMR-based supplies.

Figure 2 displays the annual hydrogen production mix and Table 4 details the individual market shares of the hydrogen suppliers under the different scenarios. Overall, they show that the ownership structure retained for PtG has a significant impact on its operations. For example, the annual production of PtG-based hydrogen decided by a firm with VRE generation (see the "*E-VRE*" scenario) is 10.5 TWh, that is, two to three times larger than that observed when PtG is operated by either an independent owner (see "*H-NewProd*") or a thermoelectric generator ("*E-CCGT*"). Similarly, there are also substantial differences in the market shares captured by PtG supplies in the hydrogen market.

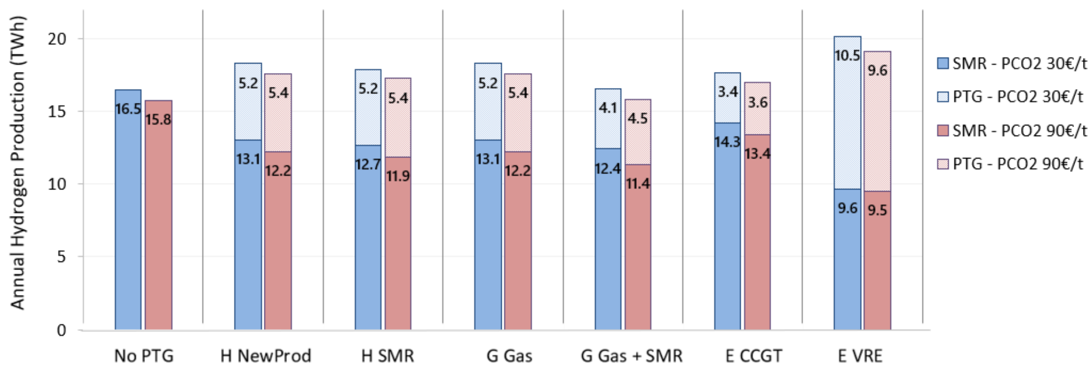

Figure 2: Annual production (in TWh) of SMR-based and PtG-based hydrogen per scenario with carbon prices of €30 and €90 per tCO_2.

Table 4: Market shares in the hydrogen market by scenario (%)
(Note: In each scenario, asterisks signal an integrated multi-market player operating the two technologies)

	NoPtG	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
G-Gas+SMR	80.2	62.8	66.2	62.8	52.8*	67.9	47.7
H-SMR	19.8	8.6	4.5*	8.6	18.9	11.2	0.11
PtG owner	0.0	28.6	29.3*	28.6	28.3*	20.9	52.19

From Figure 2 and Table 4, four remarks emerge. First, two ownership structures, namely "*H-NewProd*" and "*G-Gas*," yield exactly the same outcomes. This finding is explained by the similar behaviors posited for the PtG operator in the input and output markets (see the first-order conditions for optimality (B.11) and (B.22) in Appendix B showing that these players' marginal profits from PtG conversion are identical).[7] Furthermore, under the "*G-Gas*" scenario, the marginal profit derived by G-Gas from its natural gas supplies is strategically independent from its decisions regarding PtG operations.[8]

Second, in all scenarios, the supply of SMR-based hydrogen is dominated by the vertically integrated firm G-Gas+SMR. By withholding supplies to the gas market, that player exerts market power on its sales of natural gas and also raises the cost of its rival in the hydrogen market (*i.e.*, the specialized firm H-SMR). More generally, Table 4 also indicates that, in all scenarios except "*E-VRE*," G-Gas+SMR's strategic advantage is powerful enough to dominate the entire hydrogen market (it has the largest market share and supplies more than half the volumes). In these scenarios, the implementation of PtG is not sufficient to debunk that fossil-based supplier of hydrogen.

Third, "*E-CCGT*" exhibits a markedly smaller supply of PtG-based hydrogen (3.4 TWh) than the other scenarios. Recall that E-CCGT is a thermal generator with no VRE resources. The preliminary remark above indicates that, in this scenario, PtG and thermal generation are never used simultaneously. When PtG is operated, the firm thus sells zero power indicating that the firm's multi-market positioning does not affect its PtG decisions. Regarding PtG, E-CCGT behaves as a pure interenergetic arbitrager. Compared with the "*H-NewProd*" and "*G-Gas*" cases, its lower use of PtG simply mirrors the differences in

[7] Recal that in both scenarios, the PtG operator behaves like a price-taking firm in the electricity market and as a price-making one in the hydrogen market.

[8] In Appendix B, the decisions regarding PtG conversion affects neither the marginal revenue nor the marginal cost yielded by the supply of natural gas (see condition (B.9))

the behavioral assumption retained for the purchase of the electricity used for PtG. Recall that, being a power producer, E-CCGT can exert buyer power when purchasing that input whereas H-NewProd and G-Gas are modeled as price-taking agents. As a result, an E-CCGT firm has a tendency to withhold purchases, which explains its more restrictive use of PtG conversion than that decided by the independent operator in "*H-NewProd*."

Lastly, the large use of PtG in the "*E-VRE*" scenario deserves a discussion. Recall that the firm E-VRE is endowed with renewable resources but no dispatchable generation capacity. Absent PtG asset, it has no option but to sell, in each hour, a quantity of VRE determined exogenously by the electricity market (see (1c)). PtG-conversion makes E-VRE a strategic player capable of expelling electricity from the power market, a decision that affects the energy-specific profits earned from the sale of VRE and hydrogen. By withholding supplies from the electricity market to produce hydrogen, E-VRE increases its profit in the electricity market by raising electricity prices while capturing revenues from the hydrogen market. At the margin, an interior solution with no binding capacity constraints is such that the two marginal revenues equalize (after accounting for PtG conversion efficiency).[9] Because of that behavior, E-VRE finds it optimal to convert a much larger volume of electricity than the thermal generator E-CCGT under the scenario "*E-CCGT*." That said, our simulation results indicate that, in each hour, E-VRE always holds a net seller position in the electricity market.

4.3. Price impacts of PtG

Table 5 reports the annual average price levels observed for each energy under each scenario. Compared with the baseline scenario, the development of PtG conversion yields lower prices for hydrogen. The mean annual price of one MWh of hydrogen decreases from €84.08 under "*NoPtG*" to figures in the range (€78.6, €83.9) when PtG is controlled by a firm with no VRE generation. In contrast, the scenario "*E-VRE*" yields a noticeably

[9] Using the KKT conditions in Appendix B, an interior solution with no binding capacity constraints is such that: (i) the marginal revenue yielded by the sale of hydrogen in (B.4) – that is, the price ${\pi_d^H}^*$ minus the market power term $\sum_{h\in\mathcal{H}} w_h \cdot \frac{q^H_{p,PtG,d,h}}{b^H_d}$ – has to be equal (after correcting for PtG conversion efficiency) to (ii) the marginal revenue gained from the sale of VRE as indicated in condition (B.1) (*i.e.*, the electricity price ${\pi^E_{d,h}}^*$ minus the market power term $\frac{1}{b^E_{d,h}}\left(\sum_x q^E_{p,x,d,h} - \frac{q^H_{p,PtG,d,h}}{\gamma_{PtG}}\right)$).

lower mean annual price of €72.80. In the natural gas market, the impacts of PtG are less pronounced as only slightly lower prices are observed (*i.e.*, when PtG conversion is implemented, the average price per MWh is in €35.02 to €35.18 range compared with €35.21 in the baseline scenario). That slight decline is consistent with the drop in the demand for gas caused by the substitution of gas-based hydrogen by PtG-based supplies.

Table 5: Annual average energy prices under each scenario with $\pi_{CO_2} = 30$ €/tCO_2 (in €/MWh)

	NoPtG	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
Hydrogen	84.08	78.60	79.76	78.60	83.90	80.49	72.80
Gas	35.21	35.07	35.02	35.07	35.18	35.12	35.15
Electricity	55.77	62.00	61.97	62.00	60.38	59.47	67.37

Regarding electricity, PtG inflates the annual average price of a MWh (from €55.77 under the baseline scenario to a level in €59.47, €67.73 range in the alternative scenarios). It is important to stress that the more PtG is utilized, the larger the rise in the average power price, which is understandable given the supplementary power demand emanating from PtG conversion.

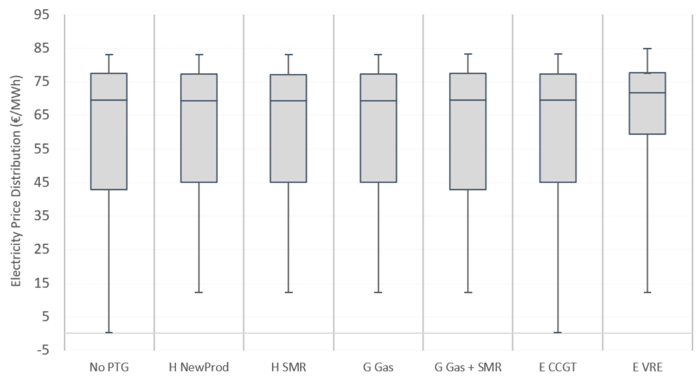

Figure 3: Boxplot of the hourly electricity prices simulated with $\pi_{CO_2} = 30$ €/tCO_2 (€/MWh)

To enrich the discussion on power prices, Figure 3 displays the distributional properties of the hourly electricity prices under the different scenarios. It shows that PtG has an asymmetrical impact on power prices since its effect concentrates on the cheaper hours. Compared with the third quartile that is almost unchanged (*i.e.*, about €77 per MWh under all scenarios), the first quartile exhibits substantial variations (*i.e.*, 60 €/MWh under the "*E-VRE*" scenario that has an intensive use of PtG compared with 43 €/MWh in the other cases). Similarly, the minimum hourly price is zero under the baseline scenario but positive and close to €12.2 per MWh under all but one of the alternative scenarios. Hence, under these alternative scenarios, there is no period with a net supply of power that is greater than the total power demand. In contrast, a notable exception is "*E-CCGT*." As pointed out in the preceding subsection, under that scenario, PtG is operated by a thermal generator capable of exerting market power in both the purchase of power and the sale of hydrogen by strategically withholding its supply of PtG-based hydrogen. Overall, these findings are broadly consistent with the ones presented in Lynch et al. (2019) and Li and Mulder (2021).

4.4. Profits, surpluses, and social welfare

4.4.1. Profits yielded by PtG ownership

For each energy, we evaluate the sectoral annual profits earned by each potential PtG owner (that is, H-NewProd, H-SMR, G-Gas, G-Gas+SMR, E-CCGT, and E-VRE) when it operates the PtG asset (that is, under the eponym scenario) and when it does not (that is, under the baseline scenario). Table 6 reports, for each firm, the difference in sectoral profits.

Table 6: The incremental sectoral profits gained from PtG ownership (Bn €)
(Note: A dash signals that this firm does not operate in this energy market)

	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
In the electricity market	—	—	—	—	0.00	+0.91
In the gas market	—	—	-0.04	-0.12	—	—
In the hydrogen market	+0.17	+0.14	+0.17	+0.15	+0.17	-0.07
Total incremental profit	**+0.17**	**+0.14**	**+0.13**	**+0.03**	**+0.17**	**+0.84**

We observe important differences in the total profitability yielded by PtG operations. Among all firms, the multi-market gas midstreamer that also supplies SMR-based hydrogen obtains the smallest total incremental gain in profit and that gain is tiny. That finding suggests that this multi-market firm may not be ideally positioned to develop PtG. In contrast, the largest gain is that of E-VRE and is about five times larger than that of H-NewProd. This suggests that VRE producers may value PtG operations more than a pure player.

An examination of the sectoral gains provides insights on the reasons for these differences. For all firms except E-VRE, PtG ownership yields a positive profit in the hydrogen market. For them, the sectoral gain of PtG-based hydrogen supplies represents the bulk of the firm's total annual gain in profit. The case of E-VRE offers a sharp contrast to that finding. For that player, a mark-to-market valuation of its hydrogen supplies poorly captures the value created by PtG. Indeed, E-VRE strategically operates its electrolyzer at a loss (€-0.07 Bn) but that apparent loss is more than compensated by the extra profits earned from the sales of VRE (€+0.91 Bn). From a strategic management perspective, that finding has an important implication. For VRE, an integrated management of its PtG operations must be preferred to a segmented approach whereby PtG is operated as a separate profit center that has to demonstrate its profitability on a stand-alone basis.

4.4.2. Welfare impacts

To gain insights on the social impacts of PtG, we compute the Marshallian surpluses obtained by each market participant and the net social welfare. Table 7 reports these annual surpluses under the baseline scenario, and the variations observed under the six alternative scenarios that include PtG.

Table 7: The annual surpluses obtained under the baseline scenario and the changes observed under the alternative scenarios when $\pi_{CO_2} = 30$ €/tCO_2 (Bn €)
(Note: the colored cell signals the owner of the PtG asset. The revenues from carbon pricing are obtained from the uncaptured CO_2 emissions from thermal generators, SMR plants, and the end-user consumption of natural gas.)

		NoPtG	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
Electricity	E-VRE	1.92	+ 0.55	+ 0.56	+ 0.55	+ 0.44	+ 0.36	+ 0.84
	E-CCGT	0.00	0.00	0.00	0.00	0.00	+ 0.17	0.00
	E-Fringe	1.95	+ 0.45	+ 0.45	+ 0.45	+ 0.34	+ 0.27	+ 0.73
Gas	G-Gas+SMR	3.21	- 0.17	- 0.15	- 0.17	+ 0.03	- 0.11	- 0.26
	G-Gas	2.70	- 0.04	- 0.05	+ 0.13	- 0.01	- 0.02	- 0.01
Hydrogen	H-SMR	0.03	- 0.02	+ 0.14	- 0.02	0.00	- 0.02	- 0.03
	H-NewProd	-	+ 0.17	-	-	-	-	-
Total producer surplus		**9.82**	**+ 0.95**	**+ 0.95**	**+ 0.95**	**+ 0.79**	**+ 0.65**	**+ 1.27**
Gas storage surplus		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen storage surplus		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total storage surplus		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Electricity consumer surplus		6.33	- 0.81	- 0.81	- 0.81	- 0.61	- 0.50	- 1.39
Gas consumer surplus		4.57	+ 0.03	+ 0.05	+ 0.03	+ 0.01	+ 0.02	+ 0.01
Hydrogen consumer surplus		0.42	+ 0.10	+ 0.08	+ 0.10	0.00	+ 0.06	+ 0.21
Total consumer surplus		**11.31**	**- 0.68**	**- 0.68**	**- 0.68**	**- 0.60**	**- 0.42**	**- 1.17**
Revenue yielded by carbon pricing		1.65	+ 0.003	+ 0.005	+ 0.003	- 0.004	+ 0.002	+ 0.024
Net social welfare including carbon pricing		**22.78**	**+ 0.270**	**+ 0.267**	**+ 0.270**	**+ 0.192**	**+ 0.231**	**+ 0.117**

From a social perspective, the short-run analysis conducted in this paper indicates that the implementation of PtG yields net increases in the net social welfare. The largest social gains are €0.270 Bn and are obtained when PtG is operated either by the independent operator "*H-NewProd*" or the gas midstreamer "*G-Gas*." The lowest gain in net social welfare is the modest €0.117 Bn obtained under the "*E-VRE*" scenario. In the latter case, a social loss can also be observed in case of a larger carbon price equal to €90 per tCO_2 (see Table D.14 in Appendix D).

Regarding the individual market participants, PtG operations raise the price of electricity and generators (in particular, E-VRE and E-Fringe that are endowed with VRE generation) benefit from the increased power prices. In contrast, gas midstreamers and SMR-based hydrogen producers are negatively affected in general. A notable exception to that finding is when these gas firms own the PtG asset.

With regard to consumer surpluses, implementing PtG increases the amount obtained by hydrogen and gas end-users. Because of the resulting increases in power prices, the operation of that conversion technology adversely affects the end-users that consume electricity. Overall, we observe that the more PtG is used, the larger these effects are on the consumer surpluses.

4.4.3. Long-run implications for PtG investment

Although our model has a short-run nature that ignores investment considerations, we now adopt a long-run perspective to examine whether the annual profits yielded by PtG are sufficient to recoup the associated investment expenditures. Following the method and assumptions in Li and Mulder (2021) regarding investment costs and lifetime of PtG (*i.e.*, a lifetime of 25 years and an investment cost of €1 mln per MWh), we evaluate the PtG annual equivalent cost of capital by multiplying the total investment cost of the capital recovery factor.[10] Considering a discount rate of 5%, the annual equivalent cost of the capital invested in a PtG asset amounts to €0.71 billion.

[10]The capital recovery factor is $\frac{i.(1+i)^n}{(1+i)^n-1}$ where i is the discount rate and n the lifetime of the asset in years.

A comparison with the net social welfare values in Table 7 indicates that, for all scenarios, that annual investment cost figure is too large to be recouped by the annual gains in net social welfare yielded by PtG integration. Hence, from a social perspective, PtG is a welfare-enhancing technology in the short run, but its contemporary investment cost is too high to make it a welfare-enhancing technology in the long term.

That said, an examination of the individual producer surpluses show that, in the two most socially desirable scenarios identified above (*i.e.*, "*H-NewProd*" and "*G-Gas*"), the owner of the PtG is unable to recoup its investment cost. In contrast, the firm "E-VRE" has an incentive to invest in PtG conversion because of its gains in producer surplus (*i.e.*, €0.84 Bn under the scenario "*E-VRE*") are larger than the required annual equivalent cost of the capital. As that scenario yields the lower social welfare, this finding suggests a divorce between the socially desirable outcome and the individual firm's incentive to invest in the PtG technology.

4.5. Environmental performance

Using the baseline scenario "*NoPtG*" as a reference, Figure 4 reports the observed changes in the sectoral emissions – namely the uncaptured CO_2 emissions from CCGT plants, SMR-units, and the end-user consumption of natural gas – under the alternative scenarios.

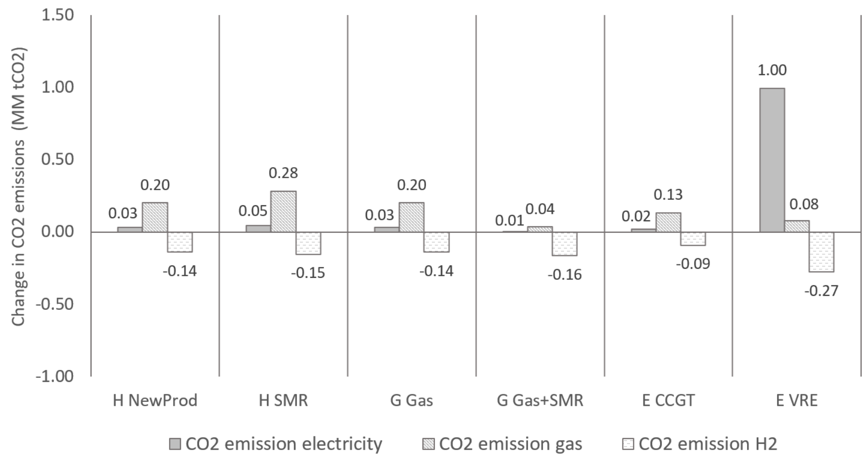

Figure 4: Impact of PtG on CO_2 emissions - change in CO_2 emissions by sector compared to the "No PtG" case when $\pi_{CO_2} = 30$ €/tCO_2

In all scenarios, the introduction of PtG reduces the CO_2 emissions from SMR-based hydrogen production (on average, -0.16 MMtCO_2) which is consistent with a reduced use of

SMR conversion. In contrast, the insertion of PtG increases emissions from the gas and electricity sectors. Regarding the gas sector, as explained in Section 4.3, PtG conversion leads to a slight decrease in the market price of gas, which stimulates its consumption by end-users. The associated incremental emissions are about +0.16 $MMtCO_2$ on average.

In the electricity sector, the increase in CO_2 emissions remains tiny (*i.e.*, about +0.02 $MMtCO_2$ on average) in all but the "*E-VRE*" scenario. In contrast, the "*E-VRE*" scenario performs poorly as the emissions from CCGT generation are much larger than the ones observed absent PtG (i.e., +1.0 $MMtCO_2$). This adverse environmental performance is due to the increase in power prices resulting from the strategic use of PtG. "*E-VRE*" is the only scenario in which we observe a simultaneous – and environmentally detrimental – use of thermal generation and PtG-conversion. That adverse effect is attenuated when a larger carbon price is used (see Appendix D.4). Unsurprisingly, a larger carbon price inflates the relative cost of CCGT generation, which negatively affects its use and thus the rise in carbon emissions.

5. Concluding remarks

All over the world, the conversion of electricity into hydrogen is currently enjoying an unprecedented momentum. Against this background, a rapidly growing stream of research is exploring the multifaceted economic consequences of a large deployment of that sector coupling technology. That research is based on models that presume either a benevolent social planner, or a perfectly competitive industry. So far, the distortions played by imperfect competition have received no attention. However, an oligopolistic organization prevails in some markets and the investors in the new hydrogen conversion capabilities are the large firms that already operate in one or several segments of the power, gas, or hydrogen industries. The fundamental issue examined in this paper is, thus, to what extent the ownership structure – in other words, the business model – retained for the conversion asset affects its profitability, the market outcomes, as well as the sectors' social and environmental performance.

To examine it, this paper proposes a new partial equilibrium model that is representative of the emerging electricity, natural gas, and hydrogen markets. Our model is specified as an instance of a Mixed Complementarity Problem that captures the essential features of the interactions between these three markets, including the presence of oligopolistic behavior by possibly multi-market firms, different power generation technologies, and different clearing frequencies for the three markets. Though the present paper is not intended to inform the national debates occurring in a specific country, we have carefully calibrated our imperfect competition model to obtain a stylized representation of a future energy system for the 2030 horizon.

From the simulation results, two key conclusions emerge. First, the operations of PtG, its market impacts, and its profitability significantly differ depending on the profile of its owner. Among the large multi-market firms, the one endowed with renewable power generation has a much greater use of – and reaps significantly larger profits from – PtG conversion than the other potential owners. That firm's strategic use of PtG leads to increased power prices which has adverse social and environmental consequences because it can cause a simultaneous use of thermal generation and PtG. We also observe that a multi-market firm supplying both natural gas and gas-based hydrogen is, on the contrary, less inclined to use PtG than an independent pure player. A similar finding also holds when PtG is operated by a thermal power producer capable of exerting market power in its purchases of green electricity. These findings show that ownership considerations matter for understanding the profitability derived from PtG operations and thus the firms' propensity to invest in this emerging technology.

Second, from a social standpoint, our findings show that the operation of PtG conversion can augment the total Marshallian surpluses yielded by market participants and change its distribution. The magnitude of the social gains also depend upon the ownership structure. The largest social gain is obtained when PtG is operated independently. In contrast, the case when PtG is operated jointly with VRE generation yields the smallest social gain. In that case, the social gain is tiny and can even turn negative in the event of larger carbon prices. Hence, the ownership organization that provides the PtG owner with the largest individual gain is also the least desirable from a social perspective.

Several possible directions can be envisioned for future research. Firstly, further research is needed on the future market design that will govern the emerging hydrogen market and on the policy and institutional measures capable of favoring the conversion of renewable-based electricity into hydrogen. That research will have to account for the presence of imperfect competition and thus represent a natural extension to the present analysis. Secondly, as the present research focuses on operations, another strand of future research could explore the players' strategic interactions when they invest in PtG. That analysis could provide useful insights for the design of the efficient policies needed to support green hydrogen. A third possible extension concerns the interactions between PtG and other emerging technologies (*e.g.*, battery storage, demand-side management involving load-shifting capabilities, bidirectional charging for electric vehicles). Such an extension would ideally necessitate the development of a technologically-enriched model capable of capturing the supply and demand uncertainties affecting the different energies.

References

Abada, I., Gabriel, S., Briat, V., Massol, O., 2013. A generalized nash–cournot model for the northwestern european natural gas markets with a fuel substitution demand function: The gammes model. Networks and Spatial Economics 13, 1–42. doi:10.1007/s11067-012-9171-5.

Blanco, H., Faaij, A., 2018. A review at the role of storage in energy systems with a focus on power-to-gas and long-term storage. Renewable and Sustainable Energy Reviews 81, 1049–1086. doi:10.1016/j.rser.2017.07.062.

Bockris, J., 1972. A hydrogen economy. Science 176, 1323–1323. doi:10.1126/science.176.4041.1323.

Bulow, J., Geanakoplos, J., Klemperer, P., 1985. Multimarket oligopoly: Strategic substitutes and complements. Journal of Political economy 93, 488–511. doi:10.1086/261312.

Bushnell, J., 2003. A mixed complementarity model of hydrothermal electricity competition in the western united states. Operations Research 51, 80–93. doi:10.1287/opre.51.1.80.12800.

Chehade, Z., Mansilla, C., Lucchese, P., Hilliard, S., Proost, J., 2019. Review and analysis of demonstration projects on power-to-x pathways in the world. International Journal of Hydrogen Energy 44, 27637–27655. doi:10.1016/j.ijhydene.2019.08.260.

Cottle, R., Pang, J.S., Stone, R., 2009. The Linear Complementarity Problem. Classics in Applied Mathematics. doi:10.1137/1.9780898719000.

Dirkse, S., Ferris, M., 1995. The path solver: a nommonotone stabilization scheme for mixed complementarity problems. Optimization Methods and Software 5, 123–156. doi:10.1080/10556789508805606.

Egging, R., Gabriel, S., Holz, F., Zhuang, J., 2008. A complementarity model for the european natural gas market. Energy Policy 36, 2385–2414. doi:10.1016/j.enpol.2008.01.044.

en Klimaat, Ministerie van Economische Zaken, 2019. National climate agreement - the netherlands - publicatie - klimaatakkoord.

ERT, 2021. Ert position paper – enablers for investing in hydrogen in europe.

European Commission, 2018. A european strategic long-term vision for a prosperous modern competitive and climate neutral economy.

European Commission, 2021a. EU Reference Scenario 2020: Energy, Transport and GHG Emissions: Trends to 2050. Technical Report. European Commission. doi:10.2833/35750.

European Commission, 2021b. "Fit for 55": Delivering the EU's 2030 Climate Target on the Way to Climate Neutrality.

European Commission, Directorate-General for Energy and al., 2021. Sector integration, regulatory framework for hydrogen : final report. Technical Report. European Commission. doi:10.2833/411951.

Fan, L., Hobbs, B., Norman, C., 2010. Risk aversion and co_2 regulatory uncertainty in power generation investment: Policy and modeling implications. Journal of Environmental Economics and Management 60, 193–208. doi:10.1016/j.jeem.2010.08.001.

Ferris, M., Munson, T., 2000. Complementarity problems in gams and the path solver. Journal of Economic Dynamics and Control 24, 165–188. doi:10.1016/S0165-1889(98)00092-X.

Frew, B., Jacobson, M., 2016. Temporal and spatial tradeoffs in power system modeling with assumptions about storage: An application of the power model. Energy 117, 198–213. doi:10.1016/j.energy.2016.10.074.

Gabriel, S., Conejo, A., Fuller, J., Hobbs, B., Ruiz, C., 2013. Complementary Modeling in Energy Markets. Springer. doi:10.1007/978-1-4419-6123-5.

Gas Infrastructure Europe, 2021. Picturing the value of underground gas storage to the European hydrogen system. Technical Report. GIE.

Green, R., Newbery, D., 1992. Competition in the british electricity spot market. Journal of Political Economy 100(5), 929–953. URL: https://www.jstor.org/stable/2138629.

Haftendorn, C., Holz, F., 2010. Modeling and analysis of the international steam coal trade. The Energy Journal 31(4), 205–230. doi:10.5547/ISSN0195-6574-EJ-Vol31-No4-10.

Holz, F., von Hirschhausen, C., Kemfert, C., 2008. A strategic model of european gas supply (gasmod). Energy Economics 30, 766–788. doi:10.1016/j.eneco.2007.01.018.

Huppmann, D., Holz, F., 2012. Crude oil market power – a shift in recent years? The Energy Journal 33(4), 1–23. doi:10.5547/01956574.33.4.1.

IEA, 2020. Projected Costs of Generating Electricity 2020. Technical Report. International Energy Agency.

IEA, 2021. Hydrogen in North-Western Europe. Technical Report. International Energy Agency.

Koirala, B., Hers, S., Morales-España, G., Ozdemir, O., Sijm, J., Weeda, M., 2021. Integrated electricity, hydrogen and methane system modelling framework: Application to the dutch infrastructure outlook 2050. Applied Energy 289, 116713. doi:10.1016/j.apenergy.2021.116713.

van Leeuwen, C., Machiel, M., 2018. Power-to-gas in electricity markets dominated by renewables. Applied Energy 232, 258–272. doi:10.1016/j.apenergy.2018.09.217.

Li, X., Mulder, M., 2021. Value of power-to-gas as a flexibility option in integrated electricity and hydrogen markets. Applied Energy 304, 117863. doi:10.1016/j.apenergy.2021.117863.

Lynch, M., Devine, M., Bertsch, V., 2019. The role of power-to-gas in the future energy system: Market and portfolio effects. Energy 185, 1197–1209. doi:10.1016/j.energy.2019.07.089.

Massol, O., Rifaat, O., 2018. Phasing out the U.S. federal helium reserve: Policy insights from a world helium model. Resource and Energy Economics 54, 186–211. doi:10.1016/j.reseneeco.2018.08.003.

METI, 2020. Green growth strategy through achieving carbon neutrality in 2050. Ministry of Economy, Trade, and Industry, Japan.

Metin, S., Dimitriadis, S., 2015. Multimarket competition. Journal of Organization Design 4, 18. URL: https://ssrn.com/abstract=3420985.

Moliner, R., Lazaro, M., Suelves, I., 2016. Analysis of the strategies for bridging the gap towards the hydrogen economy. International Journal of Hydrogen Energy 41, 19500–19508. doi:10.1016/j.ijhydene.2016.06.202.

Murphy, F., Pierru, A., Smeers, Y., 2016. A tutorial on building policy models as mixed-complementarity problems. Interfaces 46. doi:10.1287/inte.2016.0842.

Netherlands Enterprise Agency, 2022. The netherlands: list of fuels and standard co2 emission factors version of january 2022.

Open Power System Data, 2019. Pv and wind profile. URL: https://data.open-power-system-data.org/ninja_pv_wind_profiles/.

Pineau, P., Rasata, H., Zaccour, G., 2011. A dynamic oligopolistic electricity market with interdependent market segments. The Energy Journal 32. doi:10.5547/ISSN0195-6574-EJ-Vol32-No4-9.

Qadrdan, M., Abeysekera, M., Chaudry, M., Wu, J., Jenkins, N., 2015. Role of power-to-gas in an integrated gas and electricity system in great britain. International Journal of Hydrogen Energy 40. doi:10.1016/j.ijhydene.2015.03.004.

Roach, M., Meeus, L., 2020. The welfare and price effects of sector coupling with power-to-gas. Energy Economics 86, 104708. doi:10.1016/j.eneco.2020.104708.

Schill, W., Kemfert, C., 2011. Modeling strategic electricity storage: The case of pumped hydro storage in Germany. The Energy Journal 32, 59–87. doi:10.5547/ISSN0195-6574-EJ-Vol32-No3-3.

Seck, G., Hache, E., Sabathier, J., Guedes, F., Reigstad, G., Straus, J., Wolfgang, O., Ouassou, J., Askeland, M., Hjorth, I., Skjelbred, H., Andersson, L., Douguet, S., Villavicencio, M., Trüby, J., Brauer, J., Cabot, C., 2022. Hydrogen and the decarbonization of the energy system in europe in 2050: A detailed model-based analysis. Renewable and Sustainable Energy Reviews 167. doi:10.1016/j.rser.2022.112779.

Sioshansi, R., 2010. Welfare impacts of electricity storage and the implications of ownership structure. The Energy Journal 31, 173–198. doi:10.5547/ISSN0195-6574-EJ-Vol31-No2-7.

Sioshansi, R., 2014. When energy storage reduces social welfare. Energy Economics 41, 106–116. doi:10.1016/j.eneco.2013.09.027.

Thomas, A., Massol, O., Sévi, B., 2022. How are day-ahead prices informative for predicting the next day's consumption of natural gas? evidence from france. The Energy Journal 43(5), 67–91. doi:10.5547/01956574.43.5.atho.

U.S. Congress, 2022. H.r.5376 - inflation reduction act of 2022, 117th American Congress.

Vandewalle, J., Bruninx, K., D'Haeseleer, W., 2015. Effects of large-scale power to gas conversion on the power, gas and carbon sectors and their interactions. Energy Conversion and Management 94, 28–39. doi:10.1016/j.enconman.2015.01.038.

Virasjoki, V., Rocha, P., Siddiqui, A., Salo, A., 2016. Market impacts of energy storage in a transmission-constrained power system. IEEE Transactions on Power Systems 31, 1–10. doi:10.1109/TPWRS.2015.2489462.

Višković, V., Chen, Y., Siddiqui, A., 2017. Implications of the eu emissions trading system for the south-east europe regional electricity market. Energy Economics 65, 251–261. doi:10.1016/j.eneco.2017.04.033.

World Energy Council, 2021. Decarbonised hydrogen imports into the European Union: challenges and opportunitie. Technical Report. La Revue de l'Energie.

Appendix A. Overview of the alternative PtG-ownership scenarios

We consider different alternative scenarios that represent various PtG-ownership structures that can emerge. These alternative ownership scenarios are depicted in figures A.5 and A.6.

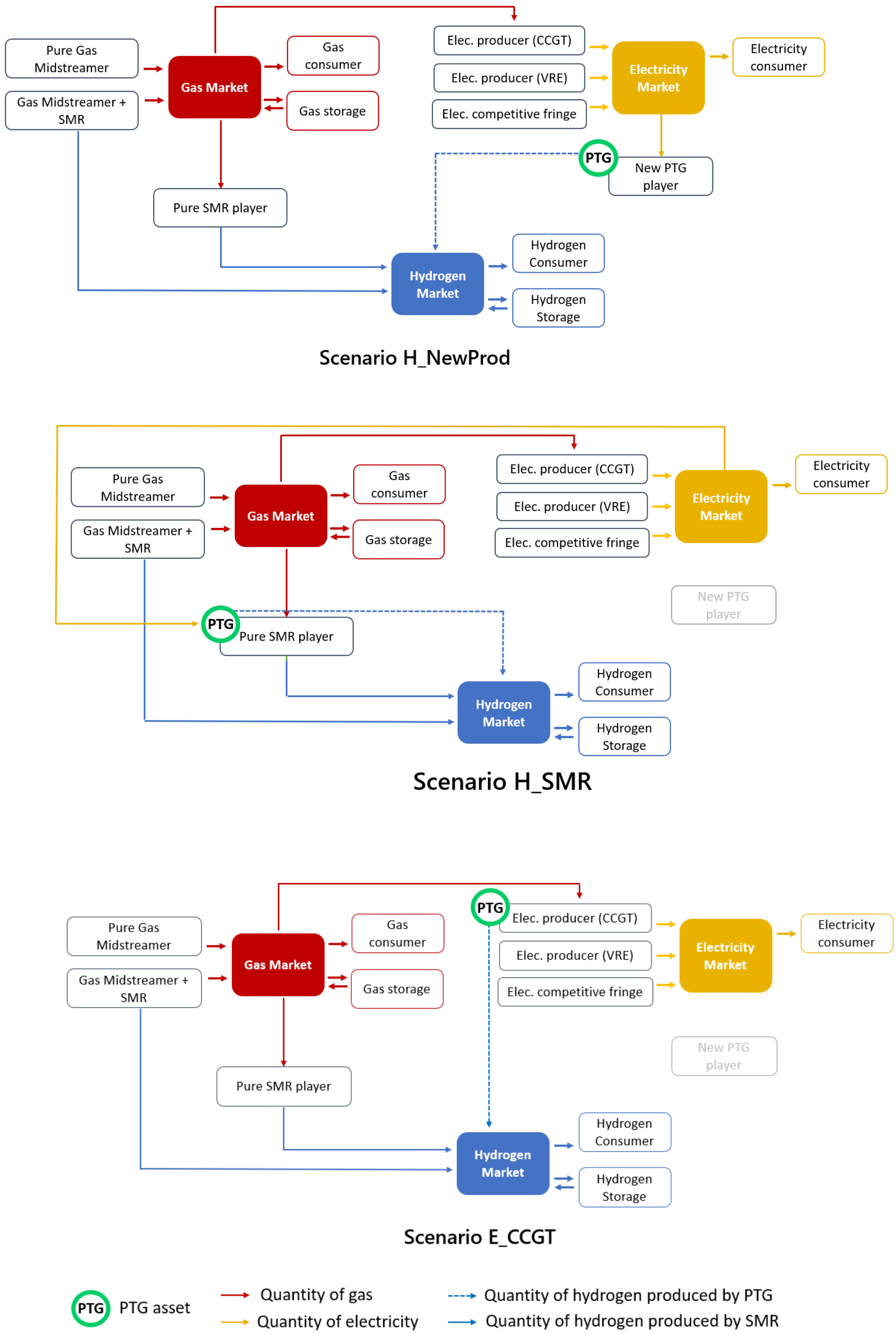

Figure A.5: Overview of the alternative PtG-ownership structures (1/2)

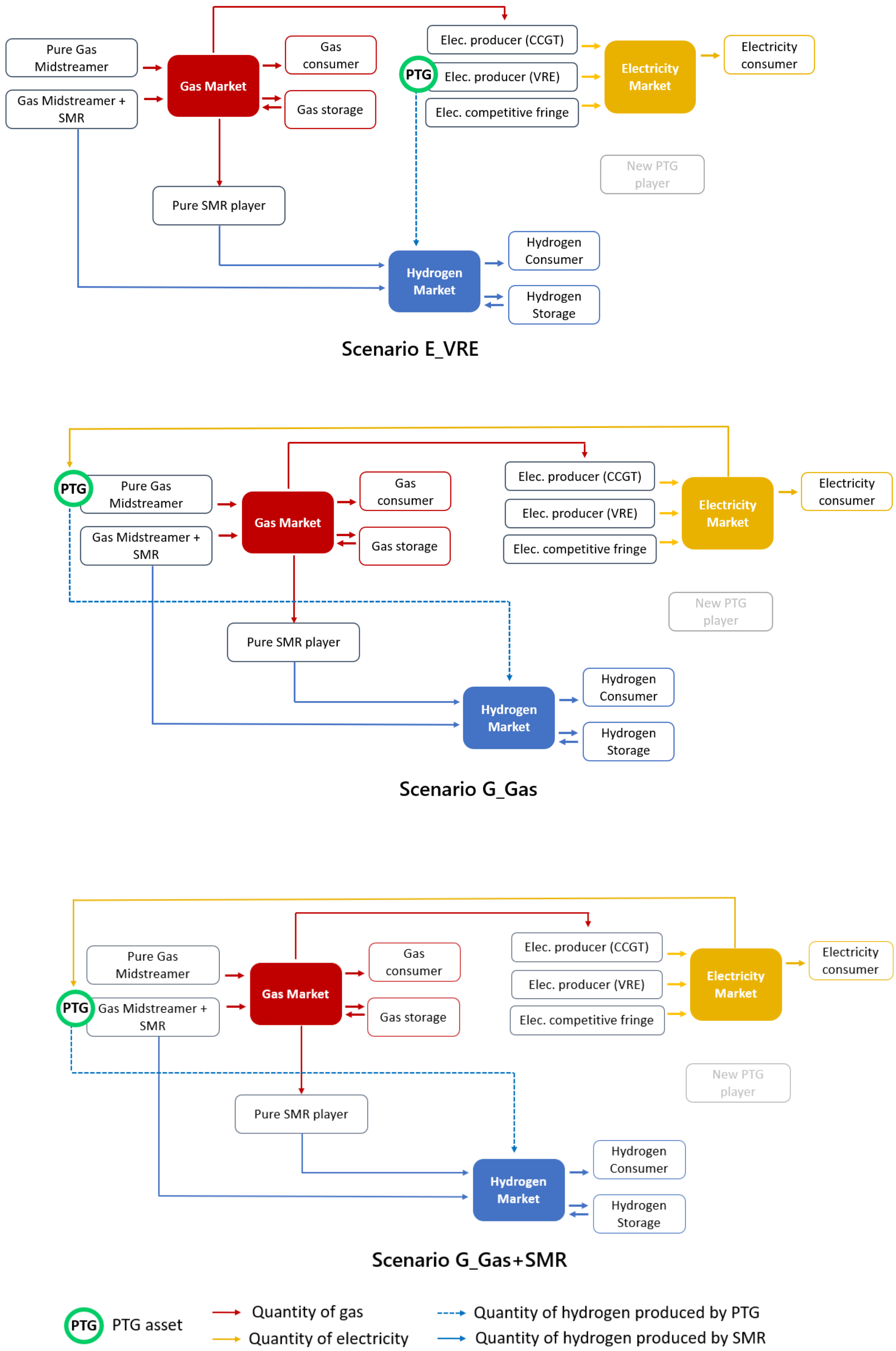

Figure A.6: Overview of the alternative PtG-ownership structures (2/2)

Appendix B. KKT conditions

From (1a)–(1g), the electricity producers' KKT conditions are:

$$0 \leq -w_d.w_h.\left[{\pi^E_{d,h}}^* - \frac{\delta^E_p}{b^E_{d,h}}\Big(\sum_x q^E_{p,x,d,h} - \frac{q^H_{p,PtG,d,h}}{\gamma_{PtG}}\Big)\right] + \lambda^{E,1}_{p,d,h} \perp q^E_{p,VRE,d,h} \geq 0 \quad \forall p,d,h \tag{B.1}$$

$$\begin{aligned}0 \leq -w_d.w_h.\left[{\pi^E_{d,h}}^* - \frac{\delta^E_p}{b^E_{d,h}}\Big(\sum_x q^E_{p,x,d,h} - \frac{q^H_{p,PtG,d,h}}{\gamma_{PtG}}\Big) - \frac{\partial C^E_{p,CCGT,d}}{\partial q^E_{p,CCGT,d,h}}\right] + \lambda^{E,2}_{p,d,h} \\ +w_d.\Big(w_h.\lambda^{E,4}_{p,d,h} - w_{h-1}.\lambda^{E,4}_{p,d,h-1}\Big) \perp q^E_{p,CCGT,d,h} \geq 0 \quad \forall p,d,h\end{aligned} \tag{B.2}$$

$$0 \leq -w_d.w_h.\left[{\pi^E_{d,h}}^* - C^{E,up}_{CCGT,d}\right] - w_h.\lambda^{E,4}_{p,d,h} \perp q^{E,up}_{p,CCGT,d,h} \geq 0 \quad \forall p,d,h \tag{B.3}$$

$$\begin{aligned}0 \leq -w_d.w_h.\left[{\pi^H_d}^* - \frac{{\pi^E_{d,h}}^*}{\gamma_{PtG}} - \frac{\delta^H_p}{b^H_d}.\Big(\sum_{h\in\mathcal{H}} w_h.q^H_{p,PtG,d,h}\Big) + \frac{\delta^E_p}{b^E_{d,h}.\gamma_{PtG}}.\Big(\sum_x q^E_{p,x,d,h}\right. \\ \left. - \frac{q^H_{p,PtG,d,h}}{\gamma_{PtG}}\Big)\right] + \lambda^{E,3}_{p,d,h} \perp q^H_{p,PtG,d,h} \geq 0 \quad \forall p,d,h,\end{aligned} \tag{B.4}$$

$$q^E_{p,VRE,d,h} = K^E_{p,VRE}.AV^E_{p,d,h} \text{ with } \lambda^{E,1}_{p,d,h} \text{ u.r.s.}, \quad \forall p,d,h \tag{B.5}$$

$$0 \leq K^E_{p,CCGT} - q^E_{p,CCGT,d,h} \perp \lambda^{E,2}_{p,d,h} \geq 0\text{‘} \quad \forall p,d,h, \tag{B.6}$$

$$0 \leq K^H_{p,PtG} - q^H_{p,PtG,d,h} \perp \lambda^{E,3}_{p,d,h} \geq 0 \quad \forall p,d,h, \tag{B.7}$$

$$0 \leq w_{h-1}.q^E_{p,CCGT,d,h-1} + w_h.q^{E,up}_{p,CCGT,d,h} - q^E_{p,CCGT,d,h} \perp \lambda^{E,4}_{p,d,h} \geq 0 \quad \forall p,d,h, \tag{B.8}$$

From (4a)–(4f), the gas midstreamers' KKT conditions are:

$$0 \leq -w_d.\left[{\pi^G_d}^* - \frac{\delta^G_p}{b^G_d}\Big(q^G_{p,d} - \frac{q^H_{p,SMR,d}}{\gamma_{SMR}}\Big) - \Big(C^G_{inter} + C^G_{slope}.q^G_{p,d}\Big)\right] \perp q^G_{p,d} \geq 0 \quad \forall p,d, \tag{B.9}$$

$$\begin{aligned}0 \leq -w_d.\left[{\pi^H_d}^* - \frac{{\pi^G_d}^* + C_{CCS}}{\gamma_{SMR}} - \frac{\delta^H_p}{b^H_d}.\Big(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PtG,d,h}\Big)\right. \\ \left. + \frac{\delta^G_p}{b^G_d.\gamma_{SMR}}.\Big(q^G_{p,d} - \frac{q^H_{p,SMR,d}}{\gamma_{SMR}}\Big)\right] + \lambda^{G,1}_{p,d} \perp q^H_{p,SMR,d} \geq 0 \quad \forall p,d,\end{aligned} \tag{B.10}$$

$$0 \leq -w_d.w_h.\left[{\pi^H_d}^* - \frac{\delta^H_p}{b^H_d}.\Big(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PtG,d,h}\Big) - \frac{{\pi^E_{d,h}}^*}{\gamma_{PtG}}\right] + \lambda^{G,2}_{p,d,h} \perp q^H_{p,PtG,d,h} \geq 0 \quad \forall p,d,h, \tag{B.11}$$

$$0 \leq K^H_{p,SMR} - q^H_{p,SMR,d} \perp \lambda^{G,1}_{p,d} \geq 0` \quad \forall p, d, \tag{B.12}$$

$$0 \leq K^H_{p,PtG} - q^H_{p,PtG,d,h} \perp \lambda^{G,2}_{p,d,h} \geq 0 \quad \forall p, d, h, \tag{B.13}$$

From (5a)-(5f) the gas storage operator's KKT conditions are:

$$0 \leq -w_d.\pi^{G\,*}_d + \lambda^{G,2}_{stor,d} + w_d.\lambda^{G,4}_{stor,d} \perp r^G_{out,d} \geq 0 \quad \forall d, \tag{B.14}$$

$$0 \leq w_d.(\pi^{G\,*}_d + C^G_{in}) + \lambda^{G,1}_{stor,d} - w_d.\lambda^{G,4}_{stor,d} \perp r^G_{in,d} \geq 0 \quad \forall d, \tag{B.15}$$

$$0 \leq \lambda^{G,4}_{stor,d} - \lambda^{G,4}_{stor,d-1} \perp u^G_{stor,d} \geq 0 \quad \forall d, \tag{B.16}$$

$$0 \leq T^G_{in}.K^G_{stor} - r^G_{in,d} \perp \lambda^{G,1}_{stor,d} \geq 0` \quad \forall d, \tag{B.17}$$

$$0 \leq T^G_{out}.K^G_{stor} - r^G_{out,d} \perp \lambda^{G,2}_{stor,d} \geq 0` \quad \forall d, \tag{B.18}$$

$$0 \leq K^G_{stor} - u^G_{stor,d} \perp \lambda^{G,3}_{stor,d} \geq 0 \quad \forall d, \tag{B.19}$$

$$u^G_{stor,d} = u^G_{stor,d-1} + w_d.\left(r^G_{in,d} - r^G_{out,d}\right) \text{ with } \lambda^{G,4}_{stor,d} \text{ u.r.s.}, \quad \forall d, \tag{B.20}$$

From (8a)–(8e), the hydrogen producers' KKT conditions are:

$$0 \leq -w_d.\left[\pi^{H\,*}_d - \frac{\delta^H_p}{b^H_d}.\left(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PtG,d,h}\right) - \frac{\pi^{G\,*}_d + C_{CCS}}{\gamma_{SMR}}\right] + \lambda^{H,1}_{p,d} \perp q^H_{p,SMR,d} \geq 0 \quad \forall p, d, \tag{B.21}$$

$$0 \leq -w_d.w_h.\left[\pi^{H\,*}_d - \frac{\delta^H_p}{b^H_d}.\left(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PtG,d,h}\right) - \frac{\pi^{E\,*}_{d,h}}{\gamma_{PtG}}\right] + \lambda^{H,2}_{p,d,h} \perp q^H_{p,PtG,d,h} \geq 0 \quad \forall p, d, h, \tag{B.22}$$

$$0 \leq K^H_{p,SMR} - q^H_{p,SMR,d} \perp \lambda^{H,1}_{p,d} \geq 0` \quad \forall p, d, \tag{B.23}$$

$$0 \leq K^H_{p,PtG} - q^H_{p,PtG,d,h} \perp \lambda^{H,2}_{p,d,h} \geq 0 \quad \forall p, d, h, \tag{B.24}$$

From (9a)-(9f) the hydrogen storage operator's KKT conditions are:

$$0 \leq -w_d.\pi^{H\,*}_d + \lambda^{H,2}_{stor,d} + w_d.\lambda^{H,4}_{stor,d} \perp r^H_{out,d} \geq 0 \quad \forall d, \tag{B.25}$$

$$0 \leq w_d.(\pi^{H\,*}_d + C^H_{in}) + \lambda^{H,1}_{stor,d} - w_d.\lambda^{H,4}_{stor,d} \perp r^H_{in,d} \geq 0 \quad \forall d, \tag{B.26}$$

$$0 \leq \lambda^{H,4}_{stor,d} - \lambda^{H,4}_{stor,d-1} \perp u^H_{stor,d} \geq 0 \quad \forall d, \tag{B.27}$$

$$0 \leq T_{in}^{H}.K_{stor}^{H} - r_{in,d}^{H} \perp \lambda_{stor,d}^{H,1} \geq 0` \quad \forall d, \tag{B.28}$$

$$0 \leq T_{out}^{H}.K_{stor}^{H} - r_{out,d}^{H} \perp \lambda_{stor,d}^{H,2} \geq 0` \quad \forall d, \tag{B.29}$$

$$0 \leq K_{stor}^{H} - u_{stor,d}^{H} \perp \lambda_{stor,d}^{H,3} \geq 0 \quad \forall d, \tag{B.30}$$

$$u_{stor,d}^{H} = u_{stor,d-1}^{H} + w_{d}.\left(r_{in,d}^{H} - r_{out,d}^{H}\right) \text{ with } \lambda_{stor,d}^{H,4} \text{ u.r.s.}, \quad \forall d, \tag{B.31}$$

Appendix C. Model parameterization

This appendix clarifies the assumptions and data sources used to calibrate the model.

Appendix C.1. Time resolution and decomposition into representative days and hours

We use a planning horizon of one year decomposed using a chronology of 40 successive subperiods. That parsimonious decomposition is sufficient to capture the essential intertemporal patterns (e.g., the use of interseasonal storages) required for our economic analysis.[11] Our chronology considers four seasons and each season has two representative days: a typical weekday followed by a typical weekend day. The typical weekday (respectively, weekend day) is chosen to be representative of the average weekday (respectively, weekend day) conditions in supply and demand that are prevailing during that season. To account for within-day fluctuations in electricity demand and supply, we further decompose each representative days using a succession of five subperiods. Each of these infradaily subperiods h has a duration of w_h hours and is modeled using a representative hour h that is identically replicated w_h times. Similarly, each representative day is replicated as many times as the corresponding number of days w_d within that season.

Table C.8a describes the chosen representative days and their associated weights w_d. Table C.8b describes the representative hours in each day and their respective weights w_h.

Table C.8: Representative Days and Hours and associated weights

(a) Representative Days

Days	Description	w_d
1	Summer - Week	88
2	Summer - Weekend	35
3	Autumn - Week	44
4	Autumn - Weekend	17
5	Winter - Week	86
6	Winter - Weekend	34
7	Spring - Week	43
8	Spring - Weekend	18

(b) Representative Hours

Hours	Description	w_h
1	10PM - 2AM	4
2	2AM - 7AM	5
3	7AM - 12AM	5
4	12AM - 5PM	5
5	5PM - 10PM	5

[11] Our model may conceivably be parameterized to represent a complete chronology involving a sequence of 8,760 hourly time steps. Compared with a less refined chronology, such a detailed time resolution can generate computational challenges without bringing much economic insights. We refer to Frew and Jacobson (2016) for further discussions on these tradeoffs.

Appendix C.2. Costs and technical assumptions

Electricity production — Cost and technical parameters

Regarding renewable generation, we assume a zero unit cost for VRE production. In contrast, the unit cost of thermal power generation $C^E_{p,x,d}$ is positive and is given by a linearly increasing function of π^G_d the endogenously determined price of natural gas (see (C.1)):

$$C^E_{p,x,d} = C^{O\&M}_{CCGT} + \frac{\pi^G_d}{\gamma_{CCGT}} + \pi^{CO_2} * \tau^{CCGT} \tag{C.1}$$

where $C^E_{p,x,d}$ denotes the total unit generation cost including operation and maintenance costs $C^{O\&M}_{CCGT}$, fuel cost, and that of CO_2 emissions. Fuel cost is based on the price of natural gas combined with γ_{CCGT}, a technical parameter representing the efficiency of a CCGT plant. The unit cost of carbon emissions is set by π^{CO_2} the posited price of CO_2 and the quantity of CO_2 emission per unit of electricity output τ^{CCGT}. The values of these parameters and that of the ramp-up costs $C^{E,up}_{CCGT,d}$ retained for CCGT generation are detailed in Table C.9.

Table C.9: Technical parameters for CCGT generation units

Parameter	Source	Value	Unit
Operational cost $C^{O\&M}_{CCGT}$	European Commission (2021a)	2.3	$(€/MWh)$
Conversion efficiency γ_{CCGT}	European Commission (2021a)	0.58	
Ramp-up cost $C^{E,up}_{CCGT,d}$	Virasjoki et al. (2016)	5.8	$(€/MWh)$
CO_2 emission per unit of electricity generated by CCGT τ^{CCGT}	Netherlands Enterprise Agency (2022) European Commission (2021a)	0.35	(t_{CO_2}/MWh)

Gas supply — cost parameters and CO_2 emission factor

Regarding the gas procurement costs incurred by a gas midstreamer, we assume its unit cost to be an increasing linear function of its individual gas supplies. That function has an intercept $C^G_{inter} = 15$ €/MWh and a slope parameter $C^G_{slope} = 0.000002\ €/MWh^2$. The CO_2 emission factor for natural gas retained in this study is 0.20 t_{CO_2}/MWh and is derived from the 2022 list of fuels and standard CO_2 emission factors (Netherlands Enterprise Agency, 2022).

Hydrogen production — cost and technical parameters

Regarding hydrogen production, Table C.10 details the values of the technical parameters retained in our simulations.

Table C.10: Hydrogen technical parameters (source: Li and Mulder (2021))

Parameter	Value	Unit
PtH conversion efficiency γ_{PtG}	0.7	
SMR conversion efficiency γ_{SMR}	0.6	
Tons of carbon produced by methane reforming ϵ^{CO_2}	0.2	(ton/MWh)
CCS cost per ton of carbon captured c^{CCS}	50	$(€/ton\ CO_2)$
Fraction of carbon being emitted by methane reforming θ	0.2	

Gas and hydrogen storage

For these underground storages, the posited working capacities and the associated injection and withdrawal rates are based on Gas Infrastructure Europe (2021). Consistent with the figures presented in that study, we retain a storage potential of 6 TWh for hydrogen storage in the Netherlands. Hydrogen storage injection and withdrawal rates are posited equal to those of natural gas storage. Storage injection costs stem from European Commission (2021a).

Table C.11: Parameters for the hydrogen and natural gas storages

Underground gas storage		
Working gas capacity K^G_{stor}	144	(TWh)
Storage injection and withdrawal rate T^G_{out} & T^G_{in}	0.02	
Storage injection cost C^G_{in}	0.7	$(€/MWh)$
Underground hydrogen storage		
Working hydrogen capacity K^H_{stor}	6	(TWh)
Storage injection and withdrawal rate T^H_{out} & T^H_{in}	0.02	
Storage injection cost C^H_{in}	0.7	$(€/MWh)$

Appendix C.3. Calibration of the demand functions

This appendix clarifies the calibration of the linear energy demand equations of the form $D_t = a_t - b_t.\pi_t$ where D_t is the quantity consumed at time t determined by the prevailing market price π_t. Our approach is similar to the one presented in Li and Mulder (2021). In each time period t, the intercepts and slope coefficients are determined from a baseline data (*i.e.*, a previously observed price level and consumption data at that time period) and a time-invariant demand price elasticity parameter ϵ. We let D^0_t and π^0_t denote the previously observed consumption and price levels. Using that notation, the intercepts and slope coefficients a_t and b_t are determined using the relations:

$$\forall t, a_t = (1 - \epsilon).D_t^0$$

and

$$\forall t, b_t = -\epsilon.\frac{D_t^0}{\pi_t^0}$$

The baseline data on price and quantities are pre-covid observations for the year 2019.

Electricity demand function

Our baseline data on electricity consumption were extracted from the transparency platform maintained by ENTSOE.[12] The corresponding electricity price data were obtained from RTE's Eco2Mix website.[13] Following Li and Mulder (2021), we posit a price elasticity of electricity demand equal to -0.3.

Gas demand function

Data on the demand for gas is from the ENTSOG transparency platform.[14] Gas prices are drawn from the World Bank Commodities Price Data (The Pink Sheet).[15] We assume that the price elasticity of the demand for natural gas is -0.3. This value is consistent with the assumptions recurrently used in the modeling literature on imperfect natural gas markets and is close to the -0.38 figure recently estimated in the econometric analysis by Thomas et al. (2022).

Hydrogen demand function

To calibrate the hydrogen demand function, the forecasts from Gas Infrastructure Europe (2021) are used and reported on a daily scale. Hydrogen price and elasticity stem from Li and Mulder (2021).

[12] https://transparency.entsoe.eu/
[13] https://www.rte-france.com/eco2mix
[14] https://transparency.entsog.eu
[15] https://www.worldbank.org/en/research/commodity-markets

Appendix D. Sensitivity study

This appendix reports a series of detailed simulation results on energy prices and social welfare that were obtained when solving our model with a posited carbon price set at €90 per ton of CO_2.

Appendix D.1. Effects of PtG on supply and demand

Table D.12 reports the annual quantities supplied and demanded. Overall, a comparison of the results obtained under the two scenarios "*NoPtG*" and "*H-NewProd*" yields similar conclusions to the ones described in subsection §4.1. Hence, a larger carbon price does not substantially change the findings. That said, a comparison with Table 3 confirms that an increased CO_2 price negatively impacts the supply of carbon-intensive energy: gas supply declines by 3% lower, and SMR-based hydrogen by 5%. The most salient reduction is experienced by thermal power generation: -55%.

Table D.12: Annual production and demand by sector under the scenarios "*NoPtG*" and "*H-NewProd*" with $\pi_{CO_2} = 90$ €/tCO_2

(a) Annual production (in TWh)

		NoPtG	H-NewProd
Electricity	VRE	87.71	87.71
	CCGT	6.15	6.22
Gas		288.21	283.47
Hydrogen	SMR	15.78	12.24
	PtG	0	5.38

(b) Annual demand (in TWh)

		NoPtG	H-NewProd
Electricity	Consumers	92.61	86.23
	Elec $\rightarrow$ H_2	0	7.69
	Curtailment	1.25	0
Gas	Consumers	251.66	252.70
	Gas $\rightarrow$ Elec	10.26	10.36
	Gas $\rightarrow$ H_2	26.30	20.40
Hydrogen		15.78	17.62

Appendix D.2. Effects of PtG on energy prices

Table D.13 reports, for each scenario, the annual average price of each energy.

Table D.13: Mean annual energy prices (in €/MWh) obtained with $\pi_{CO_2} = 90$ €$/t_{CO_2}$

Average price	No PtG	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
Hydrogen	86.36	80.68	81.73	80.68	86.12	82.65	75.93
Gas	34.57	34.43	34.38	34.43	34.54	34.47	34.41
Electricity	65.46	71.95	71.96	71.95	70.58	69.35	77.45

The trends observed in §4.3 when the CO_2 price is 30 €$/t_{CO_2}$ are also noted when the CO_2 price is 90 €$/t_{CO_2}$. However, the average electricity and hydrogen prices are higher, as the CO_2 price increases the cost of electricity production by CCGT and hydrogen production by SMR. Moreover, this increase in expenses induces a decrease in the gas demand to produce electricity or hydrogen, which reduces the average gas price.

Appendix D.3. Effects on profits, surpluses, and net social welfare

Table D.14 reports the surpluses and the net social welfare obtained under the different scenarios when the market equilibrium is computed using a carbon price equal to 90 €/t_{CO_2}. These results are similar to the ones obtained with a lower carbon price (see Section 4.4).

Table D.14: The annual surpluses obtained under the baseline scenario and the changes observed under the alternative scenarios when π_{CO_2} = 90 €/tCO_2 (Bn €)
(Note: the colored cell signals the owner of the PtG asset. The revenues from carbon pricing are obtained from the uncaptured CO_2 emissions from thermal generators, SMR plants, and the end-user consumption of natural gas.)

		No PtG	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
Electricity	E-VRE	2.25	+ 0.57	+ 0.57	+ 0.57	+ 0.47	+ 0.37	+ 0.89
	E-CCGT	0.00	0.00	0.00	0.00	0.00	+ 0.18	0.00
	E-Fringe	2.25	+ 0.47	+ 0.47	+ 0.47	+ 0.37	+ 0.28	+ 0.24
Gas	G-Gas+SMR	3.00	- 0.16	- 0.15	- 0.16	+ 0.03	- 0.11	- 0.26
	G-Gas	2.53	- 0.04	- 0.05	+ 0.14	- 0.01	- 0.02	- 0.04
Hydrogen	H-SMR	0.03	- 0.02	+ 0.16	- 0.02	0.00	- 0.02	- 0.03
	H-NewProd	-	+ 0.18	-	-	-	-	-
Total producer surplus		**10.06**	**+ 0.99**	**+ 0.99**	**+ 0.99**	**+ 0.87**	**+ 0.68**	**+ 0.80**
Gas storage surplus		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen storage surplus		0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total storage surplus		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Electricity consumer surplus		5.50	- 0.84	- 0.84	- 0.84	- 0.67	- 0.52	- 1.41
Gas consumer surplus		4.72	+ 0.04	+ 0.05	+ 0.04	+ 0.01	+ 0.02	+ 0.04
Hydrogen consumer surplus		0.38	+ 0.10	+ 0.08	+ 0.10	0.00	+ 0.06	+ 0.18
Total consumer surplus		**10.60**	**- 0.71**	**- 0.72**	**- 0.71**	**-0.66**	**- 0.44**	**- 1.19**
Revenue yielded by carbon pricing		1.59	+ 0.003	+ 0.005	+ 0.003	- 0.004	+ 0.002	+ 0.011
Net social welfare including carbon pricing		**22.25**	**+ 0.286**	**+ 0.284**	**+ 0.286**	**+ 0.210**	**+ 0.245**	**- 0.372**

Appendix D.4. Environmental performance

Using the baseline scenario "*NoPtG*" as a reference, Figure D.7 describes the changes in CO_2 emissions by sector under the scenarios that include PtG conversion when the CO_2 price is 90 €/t_{CO_2}.

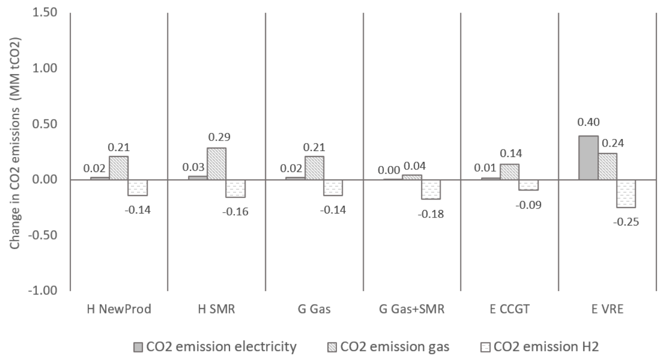

Figure D.7: Impact of PtG on CO_2 emissions - change in CO_2 emissions by sector compared to the "No PtG" case when π_{CO_2} = 90 €/tCO_2

Comparing Figure D.7 with Figure 4 shows that, in the "*E-VRE*" scenario, a carbon price of €90 per tCO_2 reduces the rise in carbon emission in the electricity sector (+0.40 compared to +1.00 $MMtCO_2$ when the carbon price is 30€/tCO_2). Indeed, increasing the price of CO_2 makes thermal power generation more expensive, which decreases its use as a replacement for VRE units.