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A system dynamics approach

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Estimating industry demand for low-carbon heating: a system dynamics approach*

Nicolas Hatem†, Olivier Massol‡

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Abstract

The decarbonation of industrial heat is key for the transition of many sectors toward carbon neutrality. However, the adoption of low-carbon heating processes in industry remains poorly documented. This article proposes an approach to estimate aggregate industrial demand curves for low-carbon heating. We adapt a "putty-clay" model from Abada et al. (2013). The model tracks the aging of industrial equipment to simulate investment decisions when equipment is replaced. Using France and Germany as case studies, we show that the model aligns well with observed trends in technology substitution. We iteratively run the model to simulate and construct aggregate demand curves for low-carbon heating processes and have three key findings. First, the delays involved in replacing industrial equipment significantly reduce the sector's medium-term decarbonation potential. We find that at most 30% of fossil-based heating equipment can be replaced by 2030. Second, the retrofit of existing natural gas equipment with mixed-feeding technologies enables faster decarbonation. Third, demand curves for low-carbon energy carriers can be well approximated by inverse logit demand functions calibrated using aggregate market data.

Keywords: industry, industrial heating, hydrogen, direct electrification, systems dynamics, demand.

JEL: Q42, Q48, R52, H77

*Work in progress, first draft, please excuse any typos and errors in the text.

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1 Introduction

Industrial heat accounts for more than 20% of global greenhouse gases (GHG) emissions and is therefore crucial to decarbonize (Thiel and Stark, 2021). There are two main mitigation pathways to reduce the carbon intensity of industrial heat: either substitute the use of fossil fuels with alternative low-carbon molecules, such as clean hydrogen and biogas, or adopt electricity-based heating systems, such as heat pumps and Joule heating (Markussen et al., 2025; Thiel and Stark, 2021). However, the implementation of these solutions remains slow to materialize. In this context, having more precise analysis on the conditions enabling the adoption of low-carbon heating processes is key to design efficient support policies.

This article is a modest contribution to the following overarching research questions: what is the aggregate demand for low-carbon heat in industry? What would be the efficient penetration of competing low-carbon heating technologies? What levels of public support are required to achieve their deployment? To contribute to these questions, we propose a methodology to estimate *ex-ante* the aggregate demand for low-carbon heat in industry.

Modeling the adoption of industry equipment is a complex exercise. A range of factors weight in industries' decision, among them, investment costs and end-use energy prices of competing technologies, policy instruments that bridge the cost gap against incumbent heating processes, path dependencies and technology lock-in (Aghion et al., 2016). The long lifetime of industry equipment also induce an inevitable delayed adjustment of capital stock with respect to prices, and hence a lag in adoption of new processes that must be accounted for (Steinbuks and Neuhoff, 2014; Keuschnigg and Stalenis, 2025).

The systems dynamics literature has developed models to precisely represent the aging of industrial capital stock and cleanly model investment decisions when renewing industry equipment. Erling Moxnes has developed a model of the sort in the 1986 to study interfuel substitutions – between coal, oil and natural gas – in industry and electricity production (Moxnes, 1986, 1990). The model developed at that time performed very well at tracking on-going changes from oil and coal to natural gas equipment. Abada et al. (2013) have re-calibrated the Moxnes model to study natural gas demand in industry. The modeling

approach proved to be, once again, very relevant at representing fuel substitution dynamics.

This article adapts a "*putty-clay*" model *à la* Moxnes from Abada et al. (2013). At the core of the model, simple equations depict the gradual aging of industry equipment. Two vintages of equipment are modeled for each heating technology. Originally only coal, oil and natural gas are used. New equipment becomes old at half of their lifetime and old equipment becomes stranded at the end of their lifetime. Industrial players choose to replace their stranded equipment within a panel of available technologies by considering the total annualized costs of different options in a discrete choice modeling framework (the "*putty*" feature of the model). Then industries use their equipment until it gets depreciated and is replaced (the "*clay*" feature of the model). Calibration is a critical step to retrieve the initial stocks of equipment in each vintage and technology. Once the equipment stock is estimated, the model can be used in ex-ante simulation exercises to study future adoption dynamics.

Taking the cases of France and Germany, we calibrate the model using long time-series on energy demand and prices in industry taken from the IEA (1978–2023).[1] We obtain a good representation of energy consumption in industry, with the model fitting very well past observed trends in substitutions between natural gas, oil and coal. We use the calibrated model to simulate the adoption of low-carbon energy processes to decarbonize industrial heating, not considered back in the 2010s. Three options are assessed: (1) the adoption of low-carbon molecules through the use of syngas, biogas or hydrogen, (2) direct electrification with Joule heating and heat pumps. The adoption of low-carbon molecules can also be done through (3), the retrofit of existing natural gas equipment in dual-fuel systems to allow for a partial blend of low-carbon molecules with natural gas. We extend the model of Moxnes to incorporate this last option. Direct electrification is only included in industry sectors with low to medium grade temperature processes, primarily using boilers.[2] The options retained in the paper encompass arrays of solutions that follow a similar logic on economic grounds. The substitution of fossil fuels to low-carbon molecules requires lower investment costs than

[1]The IEA datasets used are *World Energy Balances* and *Energy Prices*, version of 2025.

[2]Industrial heating encompasses different processes and technologies. The majority of heat is provided through indirect loops using boiling water or steam at less than 400 degrees Celsius. The remaining industrial heating demand requires higher temperature levels and use direct firing of molecules (usually fossil fuels). The electrification of this partition is deemed unfeasible in the paper.

the adoption of electric heating processes. However, associated end-use energy costs are generally higher than for electricity.

We perform the simulation by running the model on a range of end-use energy prices over 5, 7 and 9 years to study adoption in the medium-term of low-carbon heating processes. We construct aggregate demand curves with resulting price-quantity bundles. We find that by 2032 a maximum potential consumption of more than 3 Mtoe of low-carbon molecules (e.g. 1 Mton hydrogen) or of 1.2 Mtoe of electricity (100 GWh) per year can be achieved from newly installed heating equipment. This amounts to a maximum of 30% of fossil-based heating equipment replaced by 2032. Hence, a first takeaway of the model is that required delays for renewing industrial equipment significantly reduces the sector's medium-term decarbonation potential. Second, we find that allowing for retrofits of existing natural gas equipment in dual-fuels systems (e.g. "H2-ready") yields a higher Willingness-to-Pay for low-carbon molecules than when used in conventional burners, and more interestingly, could be preferred to direct electrification. Moreover, the retrofit of natural gas equipment can cut delays for equipment replacement and hence allow for a more rapid decarbonation of the sector. A third outcome of the modeling exercise is that resulting aggregate demand curves for low-carbon heating energy vectors can be well approximated by inverse logit demand functions and possibly calibrated using aggregate market data. Adopting such functional specification could significantly improve prospective studies on the development of low-carbon energy vectors (e.g. Zeyen et al. (2023)).

Through this simulation exercise we can derive policy implications. A back of the envelope computation reaffirms the fact that the amount of public support required to trigger adoptions in low-carbon heating equipment is substantial (e.g. Marmullaku et al. (2026)). Setting an exogenous target of 1 Mtoe per year of industrial heat to decarbonize by 2032 (equivalent to 86 GWh/year) amounts to granting a support of about 80 Euros per MWh for electricity throughout the period. For low-carbon molecules, using the example of hydrogen, achieving this target requires a support of about 6 Euros per kg. Such subsidy levels are equivalent to setting an additional carbon price of more than 400 Euros per ton of CO2-eq. The net abatement cost of a support policy must however be assessed in light of learning-by-

doing externalities associated with the development of new technologies, such as low-carbon molecules or large-scale heat pumps. In that regard, policy instruments supporting incremental changes, like incorporation mandates, may prove to be cost-effective by triggering the early retrofit of natural gas equipment into dual-fuels systems and prompt an earlier deployment of low-carbon molecules. This is left for further research.

1.1 Literature

The economic literature has extensively studied how industries' input demand react to changes in input prices, notably carbon pricing in the context of climate mitigation policies. They show that industries can increase their spending in clean technology investments, R&D, or switch to cleaner inputs, however to a lesser extent (Colmer et al., 2025; Aghion et al., 2016; Steinbuks and Neuhoff, 2014). This strand of the literature does not study the precise channels for adopting low-carbon technologies with detailed representation of industry operations and technologies' characteristics. Investigating the net benefits associated with the adoption of different, competing, low-carbon technologies is however crucial to better inform and design second-best policies to support the development of specific technologies (e.g. biogas, hydrogen) at their efficient penetration level.

Another part of the literature simulates the deployment of low-carbon technologies, with several modeling approaches that coexist. Integrated Assessment Models (IAM) conduct projections of the global economy integrated with the environment and simulate cost-efficient decarbonation pathways under different macroeconomic scenarios. These models most often integrate a detailed representation of energy systems to study the arbitrages in the adoption of different abattement technologies (van der Zwaan et al., 2025; Schreyer et al., 2024). However, they do not necessarily aim at eliciting demand curves for specific energy carriers.

Alternatively, partial equilibrium models focus on detailed representations of energy systems only, and investigate cost-optimal sequences of actions to achieve exogenous GHG emissions reduction targets. Some models use estimates of energy-price elasticities to partially endogeneize the demand for energy inputs (e.g. the TIMES model). Other models assess cost-optimal technology deployment trajectories under exogenous energy demand (Zeyen et

al., 2023; Seck et al., 2022). Such approaches have the drawback of taking a social planner point of view, where a low-carbon option is adopted as soon as the shadow price of the carbon constraint in the optimization allows it to. They do not explicitly study end-use price levels required to trigger adoptions by decentralized actors (Böhringer and Rutherford, 2008).

The model used in this article focuses on representing adoption decisions in the industry sector. The aggregated industry demand for energy inputs is endogenized, while keeping the gross demand for industrial goods as exogenous. Most closely related articles to ours are Weißenburger et al. (2024) and Rehfeldt et al. (2020). They use a detailed sector-specific model of industry to study fuel switching in the German industry with a focus on hydrogen adoption. The model seems to account for aging of equipment as well, in addition to great details in industry sectors' technical representation.[3] In contrast, we propose an openly replicable and transparent modeling approach based on a set of simple, yet tractable, system dynamics equations. Moreover, we study closed-form expressions to replicate the numerically obtained demand curves and propose ways to calibrate these functions using aggregated and commonly known market data. A strength of our model is that it is using data from the IEA which are standardized for OECD countries. This allows anyone accessing this data to retrieve an estimation of the vintages of capital stock in industry, and hence to re-calibrate local aggregate demand functions in different regions.

1.2 Remaining of the paper

In the remaining of the paper, an overview of the "putty-clay" model is presented in Section 2. The model is calibrated on long historical trends (1978–2023) of energy demand in the French and German manufacturing industry in Section 3. The ex-ante simulation exercise is done in Section 4, assessing the renewal of the equipment stock and adoption of low-carbon heating technologies at different price levels. Finally, a discussion is made on policy support required to trigger a given penetration level of low-carbon heat in Section 6.

[3]The FORECAST model is under property of Fraunhofer Institute for System- and Innovation Research (ISI), Germany.

In what follows, the example of low-carbon hydrogen is used to encompass the adoption of low-carbon molecules to decarbonize industrial heat. This study focuses on the demand side of the market. All constraints related to the supply of electrons and molecules (e.g. transport, storage, volatility of wholesale prices, carbon content) are outside the scope of this study and confined to problems faced by the supplier of the energy carrier. In other words, it is assumed that the industry can secure a long-term contract for the supply of the energy carrier at her site, agree on a fixed price and fixed carbon content. The industry then focuses primarily on selecting the heating equipment to keep its production process running for the next 20 years.

2 Model overview

A strand of the literature in system dynamics has worked on cleanly modeling the dynamics of changes in capital equipment in industry. They are encompassed in so-called "putty-clay" models. *Putty* stems for the adoption decision when equipments are renewed. *Clay* for the time lapse after investment is made, equipment cannot be changed before they become stranded and replaced again. Past studies have specifically modeled substitution dynamics in industry between oil, coal and natural gas. Moxnes have proposed a model of fuel substitution that fits very well with observed trends (1960 – 1983) in both industry (Moxnes, 1986) and electricity production (Moxnes, 1990). Abada et al. (2013) have updated Moxnes's model and also obtained close precision to track changes of capital stock dynamics in industry over the period 1978-2008. Leveraging on this heritage, this article re-calibrates the model for the current period until 2023. The stock variables obtained in 2023 then serve as inputs to study the demand for decarbonation options by conducting a simulation at different future time periods.

The model structure is as follows. Let fuel options (initially coal, oil, natural gas) denoted by i. The capital stock (i.e, equipment) is noted K_i for each fuel option and is measured in units of capacity to burn fuels (e.g., in $Mtoe/year$). Two stock variables are defined for each fuel. The capacity of recently installed equipment, KN_i, and the capacity of old equipment

KO_i. The dynamics of aging industry equipment are given by the following equations, for each option i:

$$\frac{dKN_t}{dt} = I - \frac{KN}{T} \tag{1}$$

$$\frac{dKO_t}{dt} = \frac{KN}{T} - \frac{KO}{T} \tag{2}$$

$$DO = \frac{KO}{T} \tag{3}$$

In words, new equipment becomes old after a use of half its lifetime, noted T, old equipment is scrapped after a use of the remaining half of the lifetime, DO_i is the quantity of scrapped equipment. The age of equipment in each fuel option follows a uniform distribution.

I_i stems for new investment needs in equipment for each fuel option, which is the product of an exogenously set industry demand for energy I and shares of investments in new equipment for each fuel option determined with a multinomial logit specification:

$$I_i = I \cdot s_i \text{ where, } s_i = \frac{e^{-\alpha C_i}}{\sum_i e^{-\alpha C_i}} \tag{4}$$

As shown in (5), shares are computed as a function of cost characteristics of each fuel option, C_i, expressed as total annualized costs per useful energy. The parameter α represents the sensitivity of industry to costs variations and is context specific.

The demand I is itself a function of scrapped equipment to be replaced and an exogenous industry demand ED, given as follows:

$$I = DO \cdot f(\frac{ED - K}{TI \cdot DO}) \tag{5}$$

Investments are determined by the difference between an exogenous demand in industrial goods and the currently installed capacity to fulfill this demand (K), plus the quantity of scrapped equipment. The parameter TI accounts for the rapidity of adjustment of capital

relative to a change in net demand, and f is a piecewise continuous function that has the following expression

$$f(x) = x + 1 \text{ if x} \geq 0$$
$$f(x) = e^{a \cdot x} \text{ if x} < 0$$

The non-linearity assumed in the range of negative values for the net demand is set to avoid simulating negative investments in times of important drops of total demand. Specifically, Moxnes justifies this choice in Moxnes (1990): "In reality, rapid demand reductions are accommodated by reductions in capacity utilization or by premature scrapping of old capacity. Investments will always be greater than zero, because some utilities will need to expand capacity even though the rest may have zero investments" (p. 9).

Finally, annual demand for each fuel option is given by the quantity of capital of each type utilized to fulfill the demand, in useful energy. The utilization of equipment, i.e. how much of the installed capacity has been used over the year to run production processes, is assumed to be the same for all industries and technologies. It is linked to the exogenous fluctuations of industry demand entering the model. Specifically, the ratio ED/K denotes for the overall capacity utilization of equipment to meet the aggregated demand in industry:

$$D_i = ED \cdot \frac{K_i}{K} \tag{6}$$

Ex-ante simulation exercise. Applying these modeling steps one can estimate an aggregate demand curve by simulating adoption decisions over multiple end-use price for the energy carrier, which acts on the probabilities s_i of adoption for each fuel option. The steps are as follows. First, the system dynamics model is calibrated to fit the long historical trend of energy consumption in industry. The objective is to retrieve the quantities of each vintage of equipment in the incumbent technologies used today for industrial heating, i.e. natural gas, oil and coal. Electricity and low-carbon molecules play a minor role in industrial heating as of 2023 hence no existing stock needs to be calibrated. Second, the evolution of the

obtained stock of equipment is simulated over next years using the system dynamics model. When replacing their equipment, industrial players have an extended set of possible technologies, including low-carbon processes. The simulation is repeated iteratively with prices for each energy carrier varying from near zero to high values in order to elicit adoption decisions. Third, quantities consumed in each energy carrier are aggregated at each price level to obtain an aggregate demand curve.

3 Data & calibration

3.1 Cost characteristics

Total costs for adopting equipment in a specific fuel option is given by the following formula:

$$C_i = \frac{CC_i}{PBT} + O_i + \frac{FP_i + CO2_i \cdot P_{co2}}{E_i} - P_i$$

Total annualized costs C_i are expressed in Euros per toe of useful energy. They are composed of capital costs (per *utoe*) annualized by the required payback-time CC_i/PBT, plus annual operations costs O_i, plus fuel price over efficiency FP_i/E_i, minus a premium P_i for the fuel option, encompassing all unobserved costs and benefits tied to the fuel option (e.g. path-dependency, lock-in, security of supply). Fuel prices, taken from IEA, are accounted with taxes. Additional carbon pricing from EU ETS allowances are accounted for in P_{co2}, the average annual price of the EU ETS,[4] applied to the carbon content of the energy carrier ($CO2_i$).

Characteristics for each technology are displayed in Table 1, expressed in Euros 2015, and are retrieved from the Danish Energy Agency (Agency, 2020) and Abada et al. (2013). Until 2023, the vast majority of industrial heat is still fulfilled by coal, oil or natural gas. Capital and operations costs are assumed to have been steady for these technologies since the last decade in real terms. In addition, we add in the array of abatement options the

[4] As first iteration we simplify the modeling of EU ETS allowances prices annual time-series. In the model, prices are evolving from 0 to 20 Euros per ton-CO2-eq over the period 2000-2020, at a linear rate. Then from 20 to 60 Euros per ton-CO2-eq over the period 2021-2023. These trends are adapted from Figure 1 in Hoogsteyn et al. (2026).

possibility to retrofit natural gas equipment into dual-fuel systems. The cost of the retrofit is assumed to be 20% of the investment and operations costs of natural gas equipment (ARUP, 2022). Historical price levels for each energy carrier are taken from the IEA *World Energy Prices* dataset and displayed in Figure A.10 in Appendix.

Table 1: Costs and characteristics of heating technologies assumptions

	Coal	Oil	Gas	Joule (elec)	Heat Pumps (elec)	Low-carbon Molecule (H2)
Boiler technologies ($T < 400°$C)						
Capex ($USD/utoe/year$)	780	125	125	280	1660	150
Payback time	5	5	5	5	5	5
Opex ($USD/utoe/year$)	70	17	17	9	45	21
Efficiency	0.90	0.94	0.94	0.99	2.75	0.94
Lifetime	25	25	25	25	20	25
CO_2 factor (tCO_2/toe)	3.9	3.2	2.3	0.2	0.2	0.1
Burner technologies						
Capex ($USD/utoe/year$)	360	25	25	–	–	37
Payback time	5	5	5	–	–	5
Opex ($USD/utoe/year$)	8	2	2	–	–	3
Efficiency	1	1	1	–	–	1
Lifetime	15	15	15	–	–	15
CO_2 factor (tCO_2/toe)	3.9	3.2	2.3	–	–	0.1

Sources: Danish Energy Agency (Agency, 2020) and Abada et al. (2013).

3.2 Calibration

The model is run and calibrated using France and Germany as case studies. The calibration is done against observed energy demands in each intial fuel option available to industry (oil, coal, natural gas) using the IEA *World Energy Balances* time-series. The aim of the paper is to evaluate the adoption of low-carbon heat. A challenge resides in having a relevant view of abattement possibilities across industrial sectors. Typically, paper, food and chemical industries require low to medium heat temperature processes ($< 400°$C) and use boilers to supply hot water and steam. These systems can be either replaced by electric heating or by alternative low-carbon fuels, such as hydrogen or biogas. On the other hand, some industrial

sectors use off-boiler (or direct firing) heating processes at high temperature grades, such as minerals, or steel, and are hardly compatible with direct electrification. For these sectors, only the use of low-carbon molecules is considered as a feasible option.

In order to have a correct representation of decarbonation possibilities by industrial sector we study separately low to medium grade temperature levels ($< 400°C$), versus high temperature grades. The first corresponds to chemical, food and paper processing industries, named *"on-boiler"* industry in the rest of the paper. The second to the steel and non-metallic minerals, *"off-boiler"* industry in the rest of the paper.[5] Figure 1 shows the evolution of total heat demand across these sectors in France and Germany.

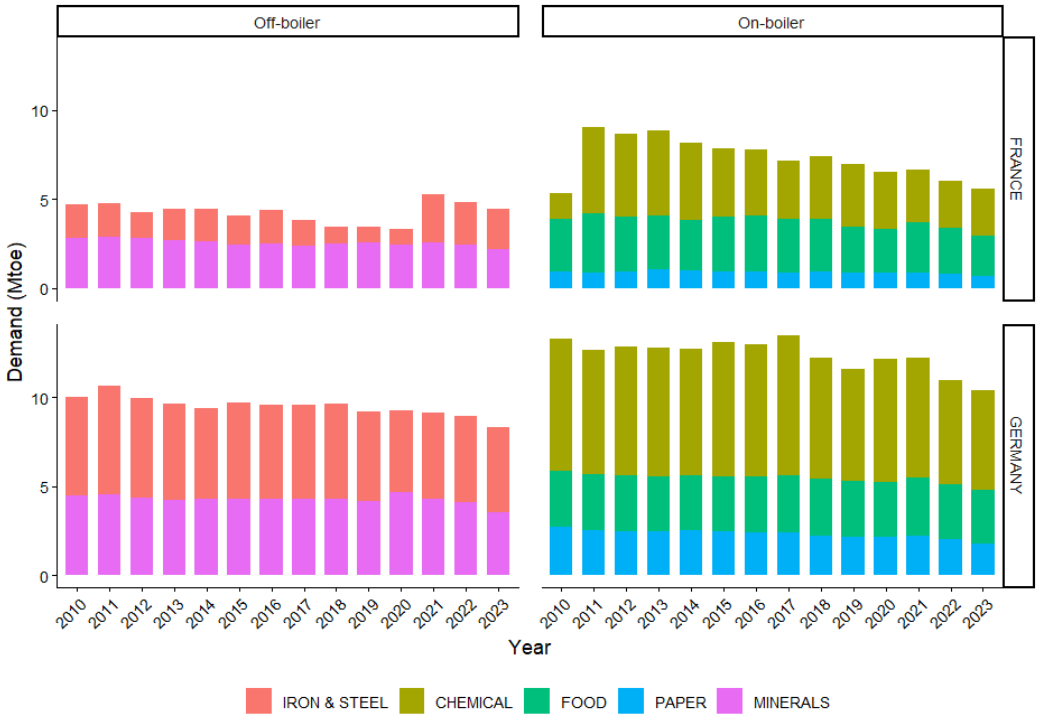


Figure 1: Total energy demanded in main industry sectors in France and Germany separated between off-boiler and on-boiler thermal processes.

Source: IEA - World Energy Balances, 2025

[5]Textiles, equipment and machinery industries are discarded from analysis since not mainly relying on heating processes. Aluminum also discarded from the analysis since mainly relying on electrolysis processes that use electricity. The remaining sectors selected in the study account for the majority of industry eneergy consumption.

The main parameters of the model are calibrated in order to minimize the difference between the historical energy demand in industry given by IEA time-series and the one obtained by the model. In words, initial quantities of capital stock in each fuel option and for each vintage (new/old equipment) must be found so that the model aligns best with observed data. We use a numerical solver to find the initial capacities that minimize the distance between observed and simulated data points over the period 1978–2023. Since the solver can only get to a local minimum we iterate this exercise by first putting initial guesses equal to the quantities of capital stocks found in Abada et al. (2013) for the year 1978 corrected at the pro-rata of the size of each sub-sector (off/on boiler). The resulting calibrated parameters are displayed in Tables 2. The coefficients α for the multinational logit specification are set at 0.02 and 0.01 for France and Germany respectively, following Abada et al. (2013).[6]

Table 2: Table of calibrated parameters.

	France			Germany		
	KN	KO	Premium	KN	KO	Premium
On-boiler industry						
Coal	0.36	0.35	0	0	0.45	0
Oil	0.02	0.31	0	0.44	0.76	0
Natural Gas	2.88	3.44	270	5.40	5.36	330
Off-boiler industry						
Coal	1.16	1.34	0	1.48	2.14	470
Oil	0.1	0.53	0	0.25	0.31	0
Natural Gas	1.0	2.02	200	2.76	2.47	280

Notes: Quantities of new (KN) and old (KO) capital stock in each fuel option obtained at the end of the study period (2023) are expressed in Mtoe/year. Premiums are country-specific and expressed in percent. Parameters are obtained by minimizing the squared residuals of the difference between observed demand (IEA) and the model using a solver (BFGS method, R).

Figure 2 displays simulated versus observed demand curves for each fuel option in the two partitions of industry. As in past studies (Moxnes, 1990; Abada et al., 2013), we obtain a good fit between IEA data and the model. Hence, the calibrated model is, arguably, appropriate to simulate future investment decisions. We observe that last decades witnessed

[6]Grid search was implemented, iterating the gradient descent on a several α values. We found that the two initial α values yields the best fit.

a sustained overall decrease in energy demand, possibly driven by the gradual improvement of industrial processes' energy efficiency as well as the reduction of the industrial sector in Europe. We also witness a substitution of the use of oil and coal toward natural gas. Interestingly, we observe that the financial crisis of 2008 prompted an important decrease in demand for natural gas for the on-boiler partition of the industry, while not significantly affecting the off-boiler partition of the industry.

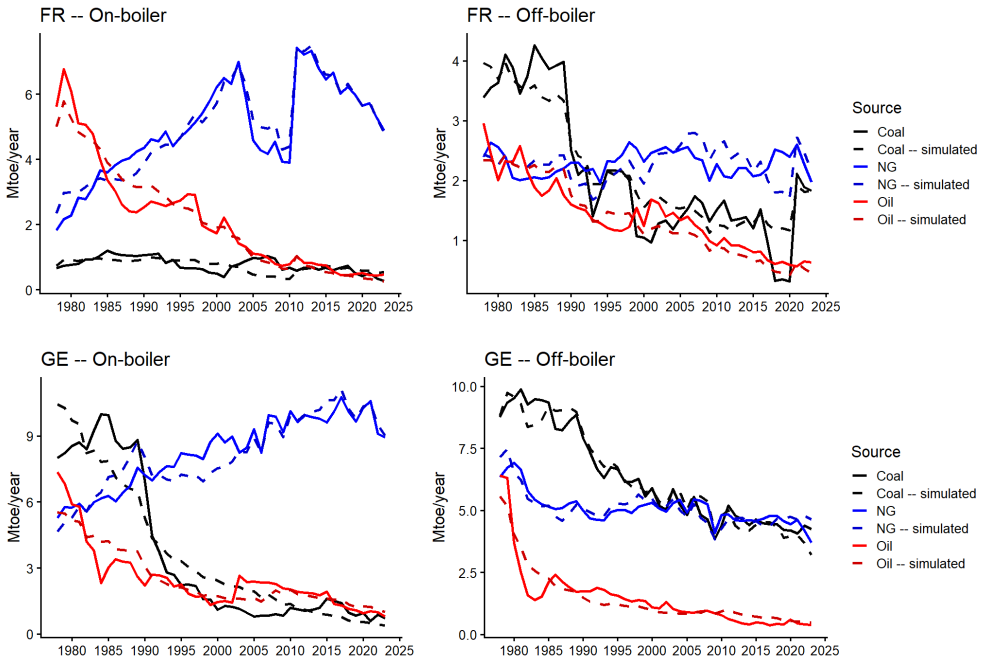


Figure 2: Calibrated model versus observed energy demand

4 Estimating demand for low-carbon heat

In this section, the calibrated model is used to simulate future adoption decisions of industry for low-carbon heating equipment in the medium-term (5, 7, 9 years). The model is run iteratively taking values from a vector of end-use energy prices to elicit the volume triggered at each price level, fixing other fuel options to their expected price level over the period. These price-quantity bundles then constitute an aggregated demand curve for the low-carbon energy vector.

First, the adoption of electric heating (Joule heating and heat pumps) in the on-boiler partition of the industry is assessed. Second, we study the adoption of low-carbon molecules, taking hydrogen (H2) as an example. Third, we add the option of retrofitting existing natural gas equipment to allow for mixed feeding with low-carbon molecules (here H2) and natural gas. This option requires adding an extension to the main model to allow for anticipated replacement of natural gas equipment. In what follows, results are presented for France.

4.1 Demand for electric heating

Figure 3 displays the demand curves for electricity to produce heat in the on-boiler partition of the industry in different time periods. The simulation is done for each price level kept constant for the number of years studied in each time period. The graph reads as follows: given that a price of 200 Euros/toe of the electron is set as of 2023, an annual demand of 250 ktoe (about 3 TWh) and 500 ktoe would materialize five years and seven years after for electricity heating systems. These volumes are triggered by industries adopting electric heating processes when scrapped is being replaced at each year in the period.

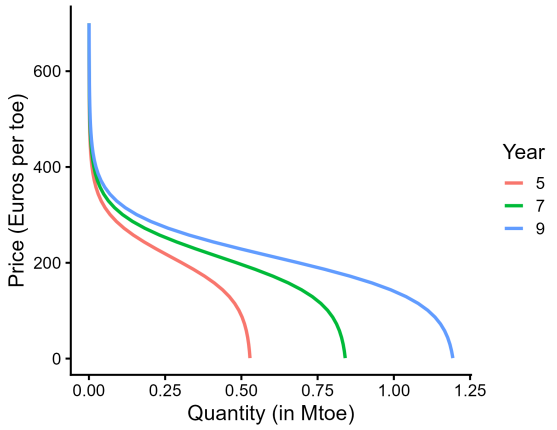


Figure 3: Demand for electric heat in the *on-boiler* industry partition. Case of France.

The first takeaway of this putty-clay modeling approach is that the multinational logit specification at the core of the model allows for smooth substitutions from natural gas to electric heating appliances. For example, it is seen that, at a price of 200 Euros per toe (about 17 Euros per MWh), significant adoption is triggered, although at this price level

equipment total costs are still 24% more expensive than natural gas. The probability of adopting electric heating at this price level is a bit less than 0.2. This feature of the model differs from usual "bang-bang" solutions in least-cost optimization delivering more realistic representations of the heterogeneity of preferences among industrial actors.

The second takeaway of this modeling approach is that the medium-term potential for decarbonation of industrial heat is constrained by the rate of replacement of capital stock and thus cannot reach the total final energy consumption in the medium-term. To put this in perspective, let's consider the French National Strategy for Net Zero (SNBC), which targets a minimum 35% reduction of emissions by 2030. Applying this target for industry, about 35% of heating demand should be substituted from fossil-based to a low-carbon heating option,[7] which accounts for about 2 Mtoe per year in the on-boiler partition of the industry (face value at the year 2023). We see from the simulation that, even with sustained zero end-use prices in the next years, the maximum quantity of low-carbon energy penetration cannot be greater than 1.2 Mtoe by 2032.

4.2 Demand for low-carbon molecules

We repeat the same exercise for the adoption of low-carbon molecules. Figure 4 displays the demand curves for low-carbon molecules, here with the example of hydrogen, to produce heat in different time periods. Low-carbon molecules have a captive market in the off-boiler partition of the industry with a maximum medium-term potential of about 1 Mtoe in 9 years.

From Panel B, we see that the Willingness-To-Pay (WTP) for a given volume of energy is very similar for electricity and low-carbon molecules. The WTP is mainly driven by end-use energy price levels, weighting more than differences in annualized investment costs for heating appliances. Higher capital costs of electricity appliances relative to low-carbon molecule is partially off-set by the lower energy costs of the former (due to higher efficiency rates). Observe in Panel B that for high energy prices (higher than 300 Euro per toe), direct

[7] assuming that majority of heat is based on natural gas we can have this simplification (pro-rata of energy demand).

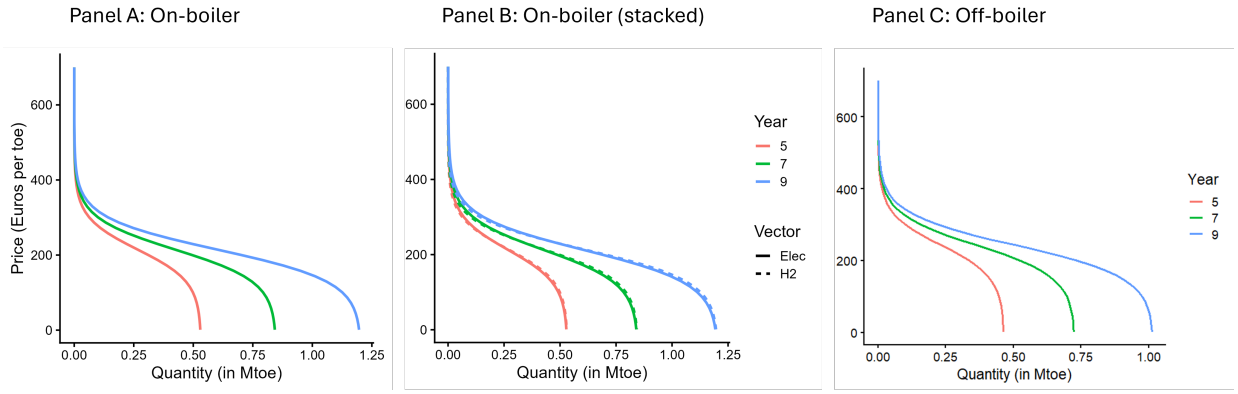


Figure 4: Demand for low-carbon molecules to supply heat in industry. Case of France.

electrification is preferred to low-carbon molecule, as energy costs savings weight more than investment costs savings. At lower energy prices levels, low-carbon molecules are preferred due to investment costs savings.

In the context of hydrogen, this comparison can be further specified. Assuming that the main low-carbon hydrogen production route is from electrolysis, the end-use price of hydrogen depends on the price of electricity. A minimum price for the supplied H2 would equal the levelized cost of electrolyzer production (LCOH), where electricity enters as the main input. Hence, by construction, the end-use price of electricity would be a lower bound of the price of H2.[8] In words, direct electrification would be always the preferred option to decarbonize industrial heat.

4.3 Demand for low-carbon molecules : allowing for dual-fuel systems

Low-carbon molecules have a distinct benefit compared to direct electrification : molecules can be injected in existing natural gas equipment and blended until a certain limit (often stated at 20%) for some amounts of retrofitting costs. This feature allows industries to partially decarbonize their existing natural gas processes without bearing too significant equipment changes. Hence, the partial replacement (or retrofit) of natural gas heating equip-

[8]Specifically, we can obtain the following inequality: $P_{H2} \simeq LCOH \simeq UFC + UVC + \frac{P_{elec}}{\eta} > P_{elec}$. Where UFC and UVC are fixed costs and maintenance cost per unit of H2 produced by electrolysis, and P_{elec}/η the cost of electricity per unit of H2 produced (η, the efficiency of the electrolyzer, is lower than one).

ment could facilitate the adoption of low-carbon molecules, allowing industries to undertake a mitigation action before the end of the life of their equipment. In the context of hydrogen, this mixed injection scheme is named "H2-ready" systems, and is named accordingly in what follows.

We modify the model to allow for retrofits of natural gas equipment into dual-fuel systems. The decision to retrofit natural gas equipment is evaluated by comparing the net savings allowed by the retrofit on the remaining years of the lifetime of the equipment. A similar logit modeling approach is done comparing the option of retrofitting to the status-quo. Since the net benefit of installing H2-ready systems is assessed on remaining years of the existing equipment, payback time is equal to the t remaining years, either 18.75 years on average for new vintages of natural gas feeders, or 6.25 years for old vintages. From technical documentation we assume the cost of the retrofit to be at 20% of the total investment and maintenance costs of the natural gas technology (ARUP, 2022). The effective end-use price and CO2 emissions rates faced by the adopters are a weighted average of the H2 and natural gas infeeds.

Figure 5 displays the resulting demand for low-carbon molecules when allowing the retrofit of natural gas equipment to dual-fuel systems. The maximum potential of low-carbon heat adoption has increased. For example, in the on-boiler partition, the maximum amount of low-carbon heat penetration reaches more than 1.5 Mtoe per year in 9 years, as compared to less than 1.25 Mtoe in Figure 3. The retrofit of natural gas equipment hence allows for more rapid decarbonation of industrial heat, which constitutes a distinct avantage of low-carbon molecules. Interestingly, Panel B shows that the resulting WTP for low-carbon molecules can become higher than for direct electrification when allowing for retrofitting. The cutoff price making H2-ready systems privately profitable with respect to other technologies is higher than for electricity, due to lower capital costs and a final price weighted with the one of natural gas.

Dual-fuel systems can also provide an additional benefit to industries, if they can adapt the level of low-carbon fuels blended with natural gas. This could allow industries to adapt the share of low-carbon energy flexibly in function of the end-use price of the latter or higher

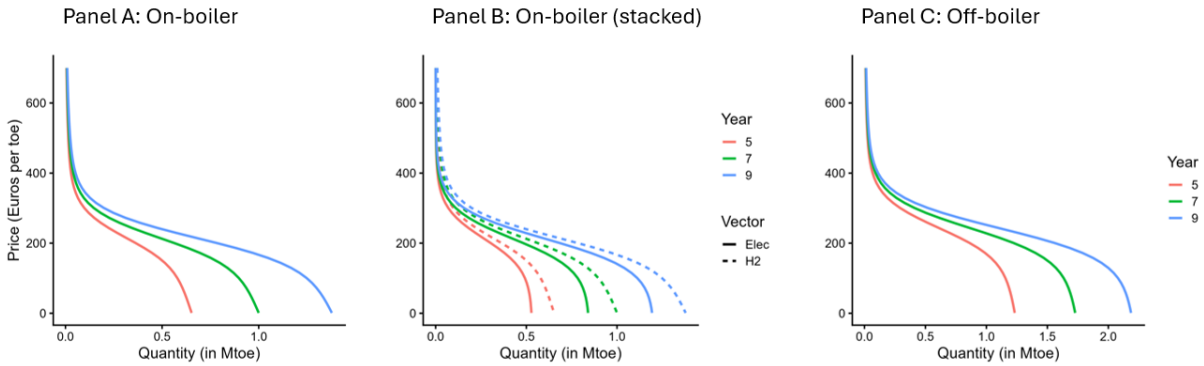


Figure 5: Demand for low-carbon heat when including dual-fuel systems ('H2-ready"). Case of France.

prices of natural gas (e.g. during a period of crisis as observed in 2022). This distinct feature is left for further research.

5 Functional form

The simulations of demand curves obtained from the model can be used to estimate the parameters of a structured demand function. Our aim is to find a functional form for the aggregate demand that best fit the simulations' results and that can be calibrated using parameters that have practical economic interpretation, hence allowing potential reuses in economic studies. While acknowledging several forms that can match the sigmoid curves obtained by the model, Abada et al. (2013) chose to approximate their demand curves with an hyperbolic tangent function of the price. The particularity of their proposed function is that it has an intercept, i.e. a quantity of fuel consumed at any price level, stemming from existing equipment that cannot be decommissioned and have to consume the fuel anyway, regardless of the cost of the intrant, to fulfill a given energy demand. This follows from the "clay" feature of the model. In our setting, the fuel options mainly involve new built capacity. In this context, the rigidity of demand coming from already installed low-carbon heating equipment is small in the medium-term. Hence, we can fit the curves obtained from our simulation by a simpler and more standard logit inverse demand function. The inverse

logit demand function is given as:

$$P(Q) = A - B \cdot \ln\left(\frac{Q}{K-Q}\right) \tag{7}$$

Where K is a saturation point at which no more additional quantity of fuel is demanded. K refers to the total capacity of stranded equipment replaced during the period, in our setting the quantity DO. A is the inflection point of the function and stems for the price at which half of the stranded capacity is replaced by the fuel option in study. It corresponds to the price level at which there is exactly the same probability of choosing the low-carbon option and the second-best alternative (in our context, mainly natural gas). B is a sensitivity parameter, a lower B implies a more price elastic demand. B can be expressed in function of the price elasticity of demand, given as follows.

$$\varepsilon(Q) = -\frac{K-Q}{K}\left[\frac{A}{B} - \ln\left(\frac{Q}{K-Q}\right)\right]. \tag{8}$$

For example, at the price level $p(K/2) = A$, we get:

$$\varepsilon\left(\frac{K}{2}\right) = -\frac{A}{2B}. \tag{9}$$

We parametrize the function in (8) using a simple OLS regression of price on quantity values obtained in simulation. Capacities K are taken from the model's results (e.g. Figure 3 reads 1.2 Mtoe for electricity at t+9 years). The right hand side in the OLS is directly put in terms of the log of the $Q/K-Q$ ratio. Parameters are displayed in Table 3, and Figure 6 shows that the fit is almost perfect.

We can observe that the values for A for each fuel option are approximately equal to the maximum price at which the total annualized cost of the fuel option becomes equal or less to the one of natural gas. Using the parameters estimated above, we can obtain the price elasticity at the inflection point of the demand curves (where $p(K/2) = A$). We get elasticities at around -2 for both energy vectors. This can be interpreted as the long-term price elasticity of low-carbon energy demand at a point where low-carbon energy carriers

Table 3: Fitted demands – parameters

			Capacity (K)		
A	B	ϵ_p	t+5	t+7	t+9
Electricity					
212	54	-2.0	0.5	0.8	1.2
Hydrogen					
147	38	-1.9	1.1	1.6	2.1
Hydrogen ("H2-ready")					
255	69	-1.8	1.2	1.7	2.2

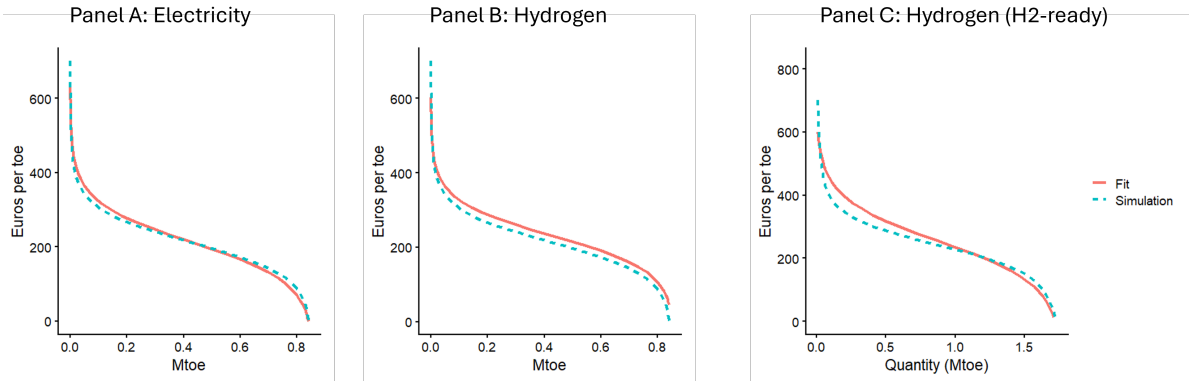


Figure 6: Simulated versus fitted logit inverse demand function at t+7 years for each fuel option.

reach cost parity with the best fossil alternative.[9]

Considering dual-fuels systems (retrofitted natural gas equipment), the WTP for low-carbon molecules, given by the parameter A, is higher than for other options. Moreover, demand is less elastic for this technology. Indeed, a significant volume of equipment is adopted even at high prices. The dual-fuel systems then become "clay" equipment, and hence have to consume low-carbon molecules at any price level, hence the rigidity in the aggregate demand.[10]

[9]This can be used to approximate the B parameter with values taken from the literature. If we assume that at this point, where low-carbon fuel option is in close competition with the cost of natural gas, we have an elasticity that is approximately equal to the long-run price elasticity of energy in industrial heating processes

[10]This is a simplification given that dual-fuel systems could allow for flexible multi-firing capacities, hence giving the possibility to run on 100% on one fuel when the other is too expensive.

6 Discussion

6.1 Sensitivity analyses

Reduction in industrial base. The model relies on an exogenously given annual industrial demand in useful heat. The difference between the annual demand and the total installed capacity then determines part of investments in new equipments. Since prospects on future industry energy demand are hasardeous, the simulation assumes a constant annual demand equal to the face value of the IEA time-series in 2023. However, the European industry is experiencing a decline both in in its production base, and energy intensity. Taking the time-series observed in each industry partition and country in Figure 1, a simple OLS regression of energy demand on year (with sector and country-level fixed effects) gives an annual decline rate of 1% on average over the period 2010-2023. We perform a sensitivity analysis repeating our simulation in 9 years taking both the historical annual decline observed in the data (1%) and more extreme decline rates (2%, 5%). Figure 7 displays the resulting demand curves in each partition of the industry. In the baseline case, under zero annual decline rate, industry is already in over capacity relative to the annual demand, as displayed in Table 2, and year-on-year only a share of stranded equipment is renewed. This is reinforced under declining overall industry demand. A 1% decline rate per year reduces the maximum size of the market for industrial low-carbon heat by more than 30% in 2032. A 5% decline rate per year reduces its size by a factor 3. Hence, prospects on industry demand for low-carbon energy carriers are very sensitive on overall macroeconomic trends.

Energy prices shock. The model relies on exogenously given energy prices. The simulation has been done under constant energy prices, averaged over the period 2018–2020 to have representative levels in "normal" conditions. However, starting from 2021, Europe witnessed multiple shocks on energy prices which compel us to redefine what are normal price levels. In an alternative exercise, we perform our simulation taking constant energy prices averaged over the period 2021–2023 instead, where Europe was severely impacted by an energy prices shock due to Russia's invasion of Ukraine. Figure 8 displays demand curves

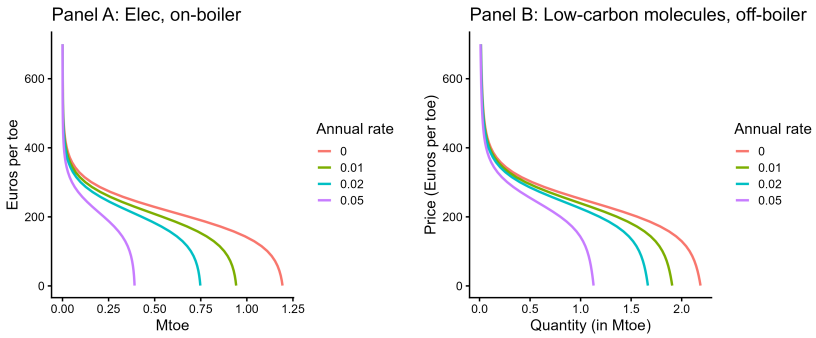


Figure 7: Demand curves in 2032 for low-carbon heat in France assuming different decline rates of industry consumption over the period

for low-carbon heat in the two partitions of the industry with high versus low energy prices. We see in Panel A that the WTP for direct electrification almost doubles under post-2021 energy prices. The WTP for low-carbon molecules experiences a smaller increase. Indeed, higher gas prices accelerate the retrofit of equipment in dual-fuel systems, to more rapidly accommodate low-carbon molecules. In years following the initial price surge, industries are constrained by their newly installed dual-fuel equipment and have to consume gas regardless of the price.

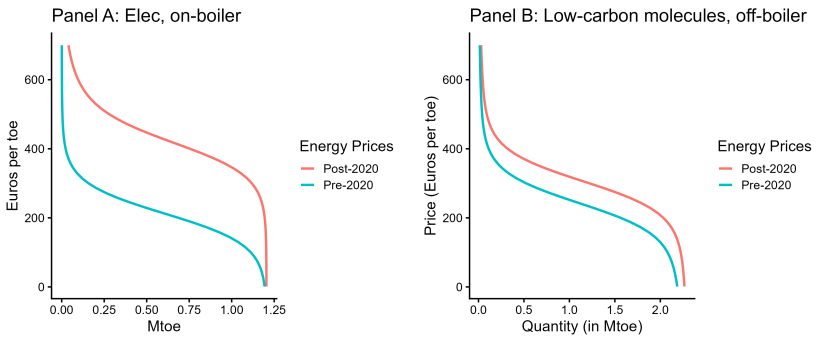


Figure 8: Demand curves in 2032 for low-carbon heat in France assuming low vs high energy prices levels

6.2 Level of policy support

The resulting aggregated demand curves can serve as a basis for economic evaluation. To illustrate this point, we provide a simple back of the envelope estimation of the level of public

support required to decarbonize industrial heat in France. For electricity, industry retail prices are taken from the French Ministry of Energy and set at 1100 Euros per toe.[11] For hydrogen, a lower bound of the LCOH is set at the price of electricity divided by electrolyzers' efficiency and equals 1800 Euros per toe. The difference between prices that trigger adoption in the model and currently observed price levels reflects a private profitability gap hindering the adoption of low-carbon heating. The use of support schemes is justified in this context, under the rationale that market failures prevent prices to reflect the true social benefits of decarbonizing industrial heat.

A support policy can subsidize the price of low-carbon energy vectors in order to make investments privately profitable. For example, in France, a first round of public auctions to support electrolyzers' production is to be issued in 2026.[12] In a static setting, assuming price levels are steady in real terms and that the impact of additional industry demand on supply costs is negligible[13], the efficient level of support amounts to the price gap to fulfill in order to trigger a required level of investments. In the on-boiler industry, setting an exogenous target of 1 Mtoe per year of low-carbon heat in 9 years amounts to granting a support of 900 Euros per toe for electricity throughout the period, which amounts to 78 Euros per MWh, and a support of 1,600 Euros per toe for hydrogen, equivalent to 6 Euros per kg. For the off-boiler industry the subsidy to hydrogen would amount to 5.5 Euros per kg.[14] These subsidy levels are equivalent to setting an additional carbon price of more than 400 Euros per ton of CO2-eq for direct electrification and more than 650 Euros per ton for hydrogen.

Upfront support for heat pumps. In the current setting, heat pumps are too expensive to be adopted in the model. The bulk of the electrification of low-to-medium temperature heat is done through the use of Joule heating appliances. Heat pumps are competitive against

[11] Average of 110 Euros per MWh observed in 2025, 2019, 2018 retrieved from the Ministry statistical office for energy (SDES) and converted in Euros 2015 per toe.

[12] See public auctions to support hydrogen production framed by the Direction générale de l'énergie et du climat (DGEC), technical report here: CRE (2025).

[13] This is likely to be false for hydrogen where the technology is nascent and increases in installed capacity of electrolyzers could prompt learning spillovers and decrease production costs. Hence a lower bound of the LCOH was used, ignoring all capital costs that are subject to learning effects.

[14] These back of the envelope estimates can be simply retrieved from aggregate demand curves in Figures 3 to 5.

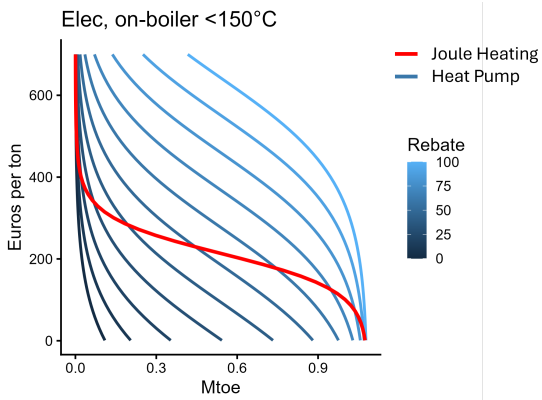


Figure 9: Demand curves for heat pumps and Joule heating in 9 years for different levels of heat pump investment rebates in (%)

Joule heating at high energy prices levels: at the point where the savings on electricity costs generated by the heat pump can offset the higher investment cost of the latter. However at such electricity price levels, natural gas equipment is always more profitable than electricity.

Policy support targeted at the adoption of heat pumps among other electrification options can be justified given the higher efficiency of the technology, reducing system level costs to meeting electricity demand, and given learning-by-doing effects that materialize at the sector level from the deployment of the nascent technology.

We conduct an alternative exercise to study the level of upfront support that is required to trigger the adoption of heat pumps in the medium-term. We simulate the adoption of heat pumps in the on-boiler partition of the industry under T°C 150 for a range of investment rebates ranging from 0 to 100% of the initial cost of the heat pump. Resulting demand curves are displayed in Figure 9. We see that with no rebate, the WTP for heat pumps, the cutoff price at which industries are willing to adopt the technology, is always lower than for Joule heating. When increasing upfront support, the WTP for heat pumps starts becoming higher than for Joule heating. For example, to trigger the substitution of 0.6 Mtoe of heat supplied from natural gas to electricity either a long-term price of 200 Euros per toe would be required for Joule heating, or a rebate of 60% on investments costs coupled with a long-term price of 300 Euros per toe is required for heat pumps.

7 Conclusion

The objective of this paper is to propose an approach to estimate aggregate demand for low-carbon heating processes in industry. We adapt an existing "putty-clay" model from Abada et al. (2013) to represent equipment changes and adoption decisions in industry. The model can be calibrated with IEA data, and used to simulate aggregate demand curves for main low-carbon heating solutions to decarbonize industry, namely direct electrification and low-carbon molecules. A first implication of this method is that inevitable delays in adjustment of capital stock, due to the life cycle of equipment, could substantially reduce the medium-term decarbonation potential of industry and increase abattement costs in the sector. A second implication of this method is that aggregate industry demand for low-carbon heating can be fitted with, closed-form, inverse logit demand functions. The obtained functions can be replicated and transferred to other contexts conditional on having information on the maximum capital stock potential that could be replaced by low-carbon equipment, on the cutoff price of the low-carbon energy vector against the best alternative option, and on the long-term energy-price elasticity in the sector. Overall, the approach proposed in this paper is intended to have a transparent estimation of demand grounded on stylized sectoral reality without relying on a "blackbox" bottom-up, nor on an overly simplistic top-down modeling approaches. The model can be easily replicated to other OECD countries for which the two IEA datasets used for calibration are available.

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A Supplementary Figures

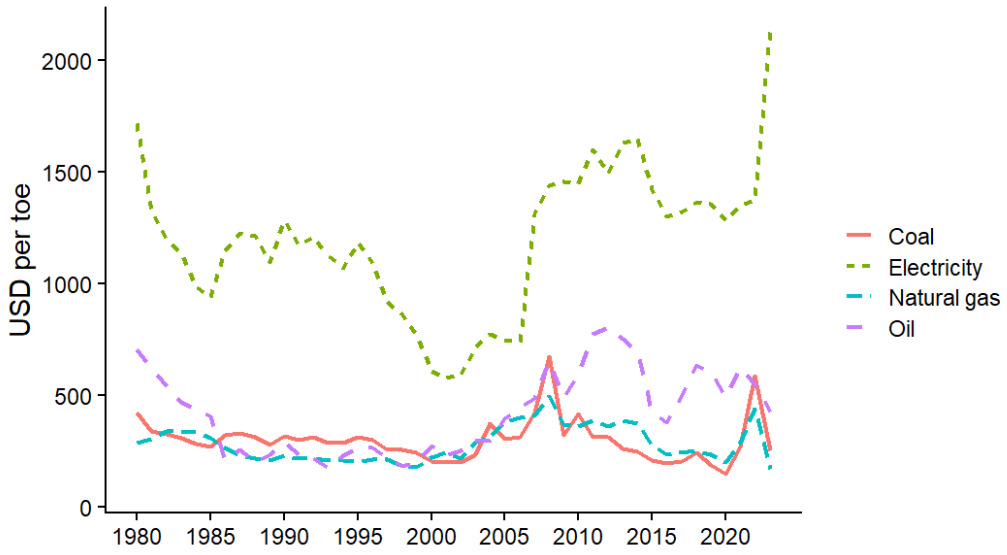


Figure A.10: Evolution of Energy prices in France. IEA Energy Prices, 2025