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Integrated optimization model for hydrogen supply chain network design and hydrogen fueling station planning

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Abstract

This paper focuses on developing a mathematical model that covers the entire hydrogen supply network. The classical hydrogen supply chain network design (HSCND) model is integrated with the hydrogen fueling station planning (HFSP) model to generate a new formulation. The proposed model considers the feedstock supply, the installation and operation of hydrogen facilities, the operation of transportation technologies, and the carbon capture and storage (CCS) system. Two primary hydrogen fueling technologies, namely on-site fueling (hydrogen is produced on-site) and standard fueling (hydrogen is delivered by road), are considered. The problem is formulated as a mixed-integer linear programming (MILP) model that minimizes the least cost of hydrogen (LCOH). The necessity of considering various components within a single framework is demonstrated through a case study in Franche-Comté, France. The role of each key model component (such as the fueling technology, feedstock transportation, and CCS system) is analyzed. The proposed model is capable of studying the interactions that exist between different parts of a hydrogen supply network. Consequently, more comprehensive construction plans for the HSCN are guaranteed.

Keywords: Integration, Optimization model, Hydrogen supply chain network, Hydrogen fueling station, MILP.

1. Introduction

The transportation sector is one of the most significant contributors to greenhouse gas (GHG) emissions. It accounted for 26% of EU, 28% of U.S., and 23% worldwide of total GHG emissions in

Abbreviations: BG, biomass gasification; CCS, carbon capture and storage; FCEV, fuel cell electric vehicle; FCLM, flow-capturing location model; GH₂, gaseous hydrogen; HFSP, hydrogen fueling station planning; HSCN, hydrogen supply chain network; HSCND, hydrogen supply chain network design; LCOH, least cost of hydrogen; LH₂, liquid hydrogen; MILP, mixed-integer linear programming; OD, origin–destination; SMR, steam methane reforming;

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26 recent years (Environmental Protection Agency, 2018; European Environment Agency, 2017; Sims
27 et al., 2014). Within the sector, road transportation is by far the largest category, contributing
28 approximately three-quarters of all emissions (International Energy Agency, 2015). Aggressive
29 and sustained mitigation strategies are essential if deep GHG reduction ambitions, such as the
30 two-degree scenario, are to be achieved. To this end, the equivalent of 160 million low-emission
31 vehicles will need to be on the roads by 2030, according to International Energy Agency (2017).

32 It is widely accepted that hydrogen is a critical element in the decarbonization of the transporta-
33 tion sector, which still relies almost exclusively on oil (McKinsey & Company, 2017). Hydrogen
34 can be used in electric vehicles (EVs) equipped with hydrogen fuel cells (FCEV). FCEVs are a nec-
35 essary complement to battery electric vehicles (BEVs) as FCEVs add convenience for consumers
36 with long ranges and fast fueling times. FCEVs can also provide potentially very low carbon
37 emissions (International Energy Agency, 2015). In terms of cost per mile, FCEVs will need tax
38 credits or other subsidies to be competitive with conventional cars and other types of alternative
39 fuel vehicles during the early stages of commercial implementation (M. Ruth, T.A. Timbario &
40 Laffen, 2011). However, significant cost reduction can be realized by scaling up manufacturing of
41 FCEVs and hydrogen fueling infrastructures (McKinsey & Company, 2017).

42 Although the potential environmental benefits of hydrogen in the transportation sector are
43 promising, the shift towards a hydrogen economy is challenging. Currently, the sales of FCEVs
44 look bleak. In the U.S., only about 1,800 Mirai (a mid-size FCEV manufactured by Toyota) have
45 been shipped in 2017. In contrast, 60 times as many Priuses (a hybrid electric vehicle) have been
46 sold, and Tesla has also delivered more than 50,000 electric vehicles (Carsalesbase, 2018). The
47 sluggish pace of sales for FCEVs is in part explained by the fact that only 65 hydrogen fueling
48 stations were available in 2017, compared to more than 20,000 charging stations across the U.S.
49 (Department of Energy, 2018a). This situation is often described as a “chicken-and-egg” problem
50 (Achtnicht et al., 2012). Investments in fueling infrastructures pay off only if the vehicle number
51 grows, but developing, building, and marketing vehicles are viable only with adequate fueling
52 stations (McKinsey & Company, 2017).

53 One way to solve this dilemma is to coordinate the roll-out of vehicles and infrastructure
54 development. Suppose that automobile manufacturers have chosen specific cities or areas as a
55 target. Fuel providers would need to create a construction plan to realize the coordination. Such a
56 plan involves two essential characteristics: (i) it should focus on planning the initial development of
57 infrastructures while accounting for the full range of local factors, such as geographic distribution
58 of feedstocks for hydrogen production and anticipated hydrogen demand at the fueling stations; (ii)
59 it should be an integrated plan, which means that all types of infrastructures (hydrogen production
60 plants, fueling stations, and CO₂ storage sites) are considered simultaneously. A simple example
61 of a hydrogen supply network is illustrated in Fig. 1.

62 Hydrogen is produced at a plant using biomass that is transported from a biomass warehouse.
63 The CO₂ emissions from hydrogen production are captured and transported to a CO₂ storage site.

64 Hydrogen is delivered to fueling stations and other types of consumers (e.g., a fleet of buses or
 65 stationary applications). There are also fueling stations that run autonomously, they produce hy-
 66 drogen on-site, thus do not rely on delivery. The construction plan is responsible for answering the
 67 following questions: What is the hydrogen demand, and where is this demand located? What kind
 68 of feedstock and technology should be selected to produce hydrogen? Will hydrogen be produced
 69 on-site or be delivered from production plants? How many production plants and fueling stations
 70 are needed, and where will they be located? What are the most suitable types of transportation
 71 (either for hydrogen or for feedstock)?

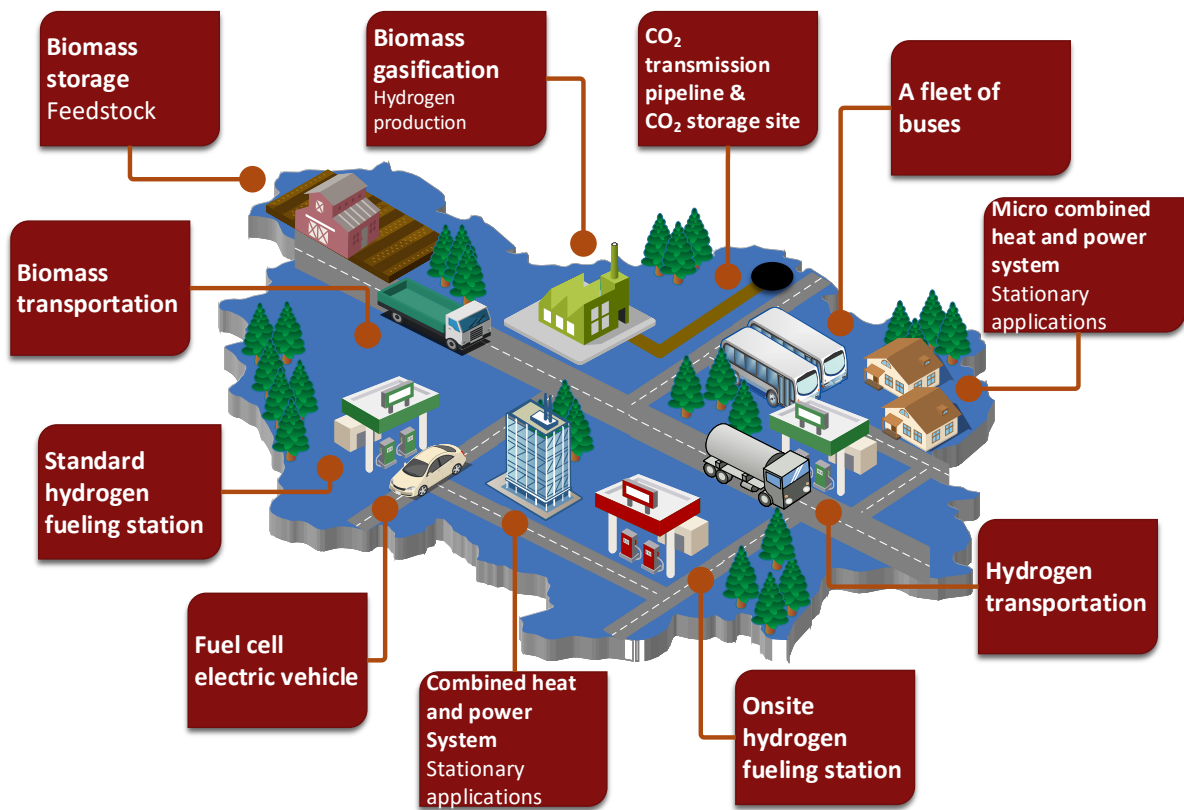


Figure 1: A simple example of hydrogen supply network

72 These questions are difficult to answer without using mathematical models because techno-
 73 logical and spatial interactions exist between the different parts of the network. Several models
 74 for hydrogen networks have been developed, and they typically fall into one of the following two
 75 categories Li et al. (2019):

- 76 • Hydrogen supply chain network design (HSCND) models: these models include multiple
 77 components such as feedstock, production, storage, and transportation. They focus on long-

78 term planning and usually run on a national scale.

- 79 • Hydrogen fueling station planning (HFSP) models: these models determine the optimal
80 location of hydrogen fueling stations. They focus on the initial development of infrastructures
81 and are generally applied at a city or regional level.

82 Unfortunately, neither the HSCND nor the HFSP models are qualified to develop the construc-
83 tion plan described above. The main reason is that neither considers the entire hydrogen supply
84 network. Most HSCND models involve no decision variables related to fueling station issues. Those
85 that do consider fueling infrastructures determine only the number, type (gaseous or liquefied hy-
86 drogen), and size of the stations. On the other hand, the HFSP models do not answer questions
87 like “where will the hydrogen come from?”. They are less concerned with the technologies of the
88 stations, and therefore do not include upstream infrastructure issues. Thus, it is reasonable to
89 combine these two types to build a new model that can cover all types of infrastructures within the
90 hydrogen supply network. In addition, the time horizon and geographic scale should be carefully
91 selected to coordinate the characteristics of these two model classes. In light of these concerns, the
92 main contributions of this paper are:

- 93 • Propose for the first time a mathematical model that covers the entire hydrogen supply
94 network (from feedstock supply to fueling stations).
- 95 • Demonstrate the necessity of considering various components within a single framework.

96 The remainder of this paper is divided into six main sections. Section 2 analyzes the relevant
97 scientific literature. Section 3 provides the problem description. Section 4 presents the proposed
98 mathematical model. Section 5 describes the setup of instances as well as the input data. Section 6
99 presents the results and discussions. Finally, Section 7 provides the conclusions and outlines some
100 plans for future development.

101 2. Literature review

102 Substantial work has been done in both the fields of hydrogen supply network design and fueling
103 station planning. The relevant literature is briefly reviewed in this section.

104 2.1. Hydrogen supply chain network design (HSCND)

105 The HSCND models fall into the category of geographically explicit optimization models. Bi-
106 nary and integer decision variables are employed to address location of facilities, sizing decisions,
107 selection of suitable production technologies, and selection of transportation modes between facil-
108 ities. Because product flows along the supply chain are modeled by continuous constraints, these
109 models are often mixed-integer formulations (Eskandarpour et al., 2015). According to Agnolucci

110 & Mcdowall (2013), three representative HSCND models have been developed by Almansoori &
111 Shah (2006) , Parker et al. (2010), and Johnson & Ogden (2012).

112 Parker et al. (2010) focused on evaluating the infrastructure requirements of hydrogen produc-
113 tion from agricultural residues. A mixed-integer nonlinear programming model based on geographic
114 information systems (GIS) was constructed for finding the most efficient and economical configura-
115 tion. Johnson & Ogden (2012) provided a network optimization tool for identifying the lowest cost
116 centralized production and pipeline transmission infrastructure within real geographic regions. The
117 model identifies the number, size, and location of production facilities and the diameter, length,
118 and location of transmission pipeline corridors.

119 Almansoori & Shah (2006) established a steady state “snapshot” model that integrates multiple
120 components within a single framework. They selected Great Britain as a case study. Later,
121 Almansoori & Shah (2009) extended their study by considering the availability of feedstocks and
122 their logistics, as well as the variation of hydrogen demand over a long-term planning horizon
123 leading to phased infrastructure development. The objective function in the model comprises
124 both operational and investment costs, split in terms of production, storage, transportation, and
125 feedstocks. The work of Almansoori & Shah (2006) is the seminal paper in this branch of the
126 literature. It has been a source of inspiration for other studies, which have attempted to improve it
127 through multiple modifications (Li et al., 2019), such as introducing multi-objective optimization
128 (De-León Almaraz et al., 2015; Guillén-Gosálbez et al., 2010; Kim & Moon, 2008), multi-period
129 optimization (Moreno-Benito et al., 2017; Murthy Konda et al., 2011; Ogumerem et al., 2018),
130 uncertainty issues (Kim et al., 2008), and integrating it with other supply chains (Agnolucci et al.,
131 2013; Cho et al., 2016; Hwangbo et al., 2017; Won et al., 2017; Woo et al., 2016).

132 Melo et al. (2009) highlighted the importance of explicitly integrating the feedstock issues into
133 SCND. However, less than half the studies cited above involve the feedstock and its logistics into
134 modeling, as shown in Table 1. It is also noted that few papers consider the possible adoption of
135 a CCS (carbon capture and storage) system, which is of great importance to meet specific carbon
136 targets when fossil energy is chosen as the feedstock. Little attention has been paid to the strategic
137 decisions related to the fueling station in HSCND models. Neither the location problem nor the
138 technology selection (i.e., standard or on-site) has been investigated. It is noteworthy that whether
139 an HSCN is based on liquid hydrogen (LH₂) or gaseous hydrogen (GH₂) is determined subjectively
140 through the definition of scenarios or configurations in most models.

141 2.2. Hydrogen fueling station planning (HFSP)

142 Most papers published in this field concentrate on the location-allocation problem of fueling
143 stations. Optimization-based approaches for locating fueling stations are divided into two main
144 groups depending on the geometric representation of demands, which are models for node-based
145 and flow-based demands (Hosseini & MirHassani, 2015).

Table 1: Strategic decisions in HSCND models

Articles	Feed.	Prod.	Transp.	CCS	Fueling station			
					Nb.	Lo.	Size	Tech.
Agnolucci et al. (2013)		✓	✓	✓	✓		✓	
Almansoori & Shah (2006)		✓	✓					
Almansoori & Shah (2009)	✓	✓	✓					
Cho et al. (2016)	✓	✓	✓					
Copado-Méndez et al. (2013)		✓	✓					
De-León Almaraz et al. (2015)	✓	✓	✓		✓			
Guillén-Gosálbez et al. (2010)		✓	✓					
Hwangbo et al. (2017)		✓	✓					
Johnson & Ogden (2012)		✓	✓	✓				
Kim & Moon (2008)		✓	✓					
Kim et al. (2008)		✓	✓					
Murthy Konda et al. (2011)		✓	✓	✓	✓			
Moreno-Benito et al. (2017)	✓	✓	✓	✓	✓			
Ogumerem et al. (2018)	✓	✓	✓					
Parker et al. (2010)	✓	✓	✓					
Samsatli & Samsatli (2015)	✓	✓	✓					
Van Den Heever & Grossmann (2003)		✓	✓					
Won et al. (2017)		✓	✓					
Woo et al. (2016)	✓	✓	✓		✓		✓	
This study	✓	✓	✓	✓	✓	✓	✓	✓

Feed.: Feedstock and its transportation; Prod.: Hydrogen production;
 Transp.: Hydrogen transportation; CCS: Carbon capture and storage;
 Nb.: Number; Lo.: Location; Tech.: Technology.

146 The node-based demand models consider each node as a demand point, and drivers would have
 147 to make specific trips to the facilities to obtain services. The main advantage of using these models
 148 is the relatively easy access to data, such as population and spatial information (Hwang et al.,
 149 2015). Nicholas et al. (2004) and Nicholas & Ogden (2006) employed the p -median model, which is
 150 one of the node-based demand models, to locate fueling stations that minimize a weighted sum of
 151 driving times to the closest station. Lin et al. (2008) also applied the p -median model to the fuel-
 152 travel-back concept and proposed a MILP formulation that minimizes the total fuel-travel-back
 153 time. Another example refers to the California Hydrogen Infrastructure Tool (CHIT), which is a
 154 geospatial analysis tool to identify the areas with the greatest need for fueling infrastructure based
 155 on a gap analysis between a projected market and current infrastructure (California Air Resources
 156 Board, 2018).

157 Many researchers argue that for fueling stations, as well as other service stations such as
 158 automatic teller machines, customer demand does not occur entirely at points, because people
 159 commonly will not make a trip solely for such a service (Jung et al., 2014). It may be more

160 realistic to model the demands as *flows* on the network, which are served “on the way”. This
161 consideration leads to the development of flow-based models (Huang et al., 2015). First developed
162 by Berman et al. (1992) and Hodgson (1990), the Flow-Capturing Location Model (FCLM) is a
163 maximum coverage model that entails facility locations to serve passing flows, which are considered
164 as captured if a facility is located on the flow paths. The basic model locates p facilities to capture
165 as much flow as possible. Many modifications have been made to extend the original FCLM, such
166 as introducing budget constraints (Shukla et al., 2011), considering the limited driving range of
167 vehicles (Kuby & Lim, 2005; Kuby et al., 2009; Lim & Kuby, 2010), relaxing the assumption that
168 all flows are on the shortest path between Origin–Destination pairs (Berman et al., 1995; Kim
169 & Kuby, 2012, 2013), and introducing fueling capacities (Hosseini & MirHassani, 2017; Hosseini
170 et al., 2017; Upchurch et al., 2009). Apart from the FCLM, there is another series of flow-based
171 models that aim to satisfy all travel demands by deploying the least number of fueling stations
172 (Wang & Lin, 2009, 2013; Wang & Wang, 2010).

173 While considerable attention has been paid to the location problem of fueling stations, the
174 influence of fueling technology on location decisions has not been given the attention it needs.
175 It will be demonstrated in the following sections that the fueling network is deeply impacted by
176 the selection of fueling technology (on-site or standard). It must also be noted that, for many
177 flow-based models, the relationship between the captured flow and the fueling capacity has been
178 neglected. In short, models cited above could tell “where” to locate the station, but neither the
179 information on “what it is” (the fueling technology) nor “how big it is” (the size) is provided.

180 *2.3. Literature summary*

181 The existing literature reveals a gap in the development of comprehensive hydrogen supply
182 network models. Some researchers have already noticed this issue. He et al. (2017) and Sun et al.
183 (2017) have proposed hydrogen station siting optimization models, which focus on the stage of
184 hydrogen source-hydrogen station. Their models optimize the number and locations of stations,
185 hydrogen source selection for the stations, and method of transportation to minimize the hydrogen
186 life cycle cost. However, the capacity of each station is pre-defined. Furthermore, the feedstock
187 and its logistics, as well as a CCS system, have not been considered in the models. There is no
188 decision variable relating to fueling technologies.

189 It is the primary purpose of this paper to fill the research gap by integrating the hydrogen
190 supply chain network design and hydrogen fueling station planning. Also, feedstock and CCS
191 issues are involved, and the model can decide the fueling technology and fueling capacity.

192 **3. Problem description**

193 The model was developed to solve the problem summarized below. Given

- 194 • The estimated total amount of hydrogen consumed by FCEVs within a region, and spatial
195 description of the region represented by an undirected graph. Each node denotes a city or a
196 large town and is characterized by
 - 197 – Demographic metrics (see Section 5)
 - 198 – Availability of each type of feedstock
 - 199 – Existence of a potential CO₂ storage site and its processing capacity
 - 200 – Existence of fixed-location demand and its amount
- 201 • A set of feedstocks, with each feedstock having the following properties:
 - 202 – Unit cost associated with its purchase
 - 203 – Correspondent production technology and transportation technology (if needed)
 - 204 – Number of units for producing 1 kg of hydrogen
- 205 • A set of production technologies, each is characterized by its:
 - 206 – Product form (gaseous or liquid hydrogen)
 - 207 – Capital, operating costs, and production capacity
 - 208 – Upstream emission factor, relating to the emissions produced by the feedstock consumed
209 and other energy inputs during their upstream processing (i.e., extraction, production,
210 and transportation)
 - 211 – On-site emission factor, relating to the emissions from the production procedure
 - 212 – Emission capture efficiency, the percent of on-site emissions that can be captured if a
213 CCS system is employed
- 214 • A set of fueling technologies (standard and on-site), each is characterized by
 - 215 – The form of hydrogen it receives (standard fueling)
 - 216 – Correspondent type of feedstock (on-site fueling)
 - 217 – Feedstock demand (on-site fueling)
 - 218 – Minimum and maximum fueling capacity
 - 219 – Capital, operating costs, and emission factor
- 220 • A set of transportation technologies, each is defined by:
 - 221 – The cargo (hydrogen, feedstock, or CO₂), and the transportation capacity
 - 222 – Capital, operating costs, and emission factor (for hydrogen transportation)

223 Determine

224 • The feedstock supply and CCS system

225 – Which nodes are selected as feedstock supply sites

226 – What type of feedstock does each selected node supply and in what quantity

227 – Which nodes are selected to build the CO₂ storage sites

228 – The processing rate of each storage site

229 • The installation and operation of hydrogen facilities

230 – The number, location, size, and technology of production plants and fueling stations

231 – Whether the network runs on gaseous or liquid hydrogen

232 – Whether a CCS system is employed at each production plant

233 – The production rate and fueling rate

234 • The operation of the transportation technology

235 – The rate of transportation of each type of cargo (hydrogen, feedstock, and CO₂) via
236 each transportation mode between all locations

237 Subject to

238 • Feedstock availability, the maximum capacity of technologies (production, fueling, CO₂ pro-
239 cessing, and transportation), and the satisfaction of all fixed-location demand and a given
240 percent of FCEV's demand.

241 In order to

242 • Minimize the least cost of hydrogen (LCOH), which includes the contribution of capital
243 investment, feedstock purchase, operating cost, and emission cost.

244 From a system modeling viewpoint, the hydrogen supply network design falls within the general
245 category of strategic supply chain management problems (Mula et al., 2010). In terms of the
246 structural features of the supply chain, the proposed model is a single-commodity (hydrogen),
247 mono-period, deterministic model with four location layers (feedstock, production, fueling station,
248 and CO₂ storage). In addition to the typical location-allocation decisions, this model also involves
249 decisions related to capacity, production, and transportation modes.

250 **4. Mathematical model**

251

252 *Sets*

- $e \in E$ feedstock types
 $f \in F$ transportation mode of feedstock
 $h \in H$ transportation mode of hydrogen
 $i \in I$ hydrogen physical forms
 $j \in J$ fueling facility sizes
 $k \in K$ production facility sizes
 $n, m \in N$ nodes
 N_q nodes on shortest path of OD (Origin–Destination) pair q
 $o \in O$ on-site fueling technologies
 $p \in P$ production technologies
 $q \in Q$ OD (Origin–Destination) flow pairs
 $s \in S$ standard fueling technologies

253 *Subsets*

- $(e, f) \in EF \subseteq E \times F$ combinations of feedstock types and transportation modes
 $(e, o) \in EO \subseteq E \times O$ combinations of feedstock types and on-site fueling technologies
 $(e, p) \in EP \subseteq E \times P$ combinations of feedstock types and production technologies
 $(i, h) \in IH \subseteq I \times H$ combinations of hydrogen physical forms and transportation modes

254

255 Considering the problem characteristics, a MILP model is developed. The model assumptions
 256 are shown below. The objective function and constraints are characterized subsequently.

257 *4.1. Model assumptions*

258 The study is based on the following assumptions:

- 259 • The length of the shortest path between each pair of nodes is regarded as the distance between
 260 the two nodes, which is given as input data;
- 261 • Two types of fixed-location demand are considered: Type A refers to stationary applications
 262 such as combined heat and power system, and Type B refers to fleet vehicles. For the former,
 263 one needs only to deliver the required amount of hydrogen, while for the latter, in addition
 264 to meeting the fixed-location demand, one should also build a standard fueling station to
 265 satisfy the fueling demand at that node;
- 266 • The vehicles required to deliver hydrogen and feedstock are rented;
- 267 • The potential locations where the CO₂ storage sites could be built are given as model inputs;

- 268 • Only the CO₂ emission of the hydrogen production plants could be captured and processed
269 by the CCS system;
- 270 • The total amount of CO₂ emission of the HSCN could be zero or negative depending on
271 the type of feedstock selected and whether a CCS system is adopted (e.g., when biomass is
272 selected as feedstock and a CCS system is also applied). Negative emissions generate revenue.
273 For simplicity, the carbon price remains the same for both positive and negative emissions.

274 4.2. Objective function

275 The optimization framework seeks to minimize the least cost of hydrogen (*LCOH*) in €/kg H₂,
276 which is attained by dividing the total daily cost (*TDC*) by the amount of hydrogen delivered per
277 day (*THD*):

$$\text{Minimize } LCOH \quad (1)$$

$$LCOH = \frac{TDC}{THD} \quad (2)$$

278 The total daily cost (*TDC*) consists of the contribution of capital cost (*CC*), feedstock pur-
279 chasing cost (*EC*), operating cost (*OC*), and emission cost (*EMC*):

$$TDC = CC + EC + OC + EMC \quad (3)$$

280 The amount of hydrogen delivered per day (*THD*) is given by

$$THD = \sum_q f_q^{pair} * IC_q + \sum_{n,i} (dem_{ni}^{h,A} + dem_{ni}^{h,B}) \quad (4)$$

281 The first term on the right-hand-side of Eq. (4) refers to the hydrogen demand of FCEVs,
282 where f_q^{pair} is the amount of hydrogen fueling demand flow of OD (Origin–Destination) flow pair
283 q , and IC_q equals 1 if flow pair q is captured. The second term refers to the fixed-location demand,
284 and $dem_{ni}^{h,A}$ and $dem_{ni}^{h,B}$ represent the fixed demand at node n (in hydrogen form i) of Type A and
285 Type B, respectively.

286 4.2.1. Daily capital cost (*CC*)

287 The capital cost is composed of facility capital cost (*FCC*) and CO₂ transportation capital
288 cost (*TCC*):

$$CC = \frac{1}{\alpha * \beta} (FCC + TCC) \quad (5)$$

289 The right-hand-side of Eq. (5) is divided by the annual network operating period (α) and the
290 payback period of capital investment (β) to find the cost per day.

291 • Facility capital cost (FCC)

$$\begin{aligned}
FCC = & \sum_{p,i,k} NP_{pik} * pcc_{pik} + \sum_{s,i,j} NF_{sij} * fcc_{sij} \\
& + \sum_{o,j} NF_{oj} * fcc_{oj} + NR * ccc
\end{aligned} \tag{6}$$

292 where NP_{pik} represents the number of production plants of technology p , hydrogen form i , and
293 size k . pcc_{pik} is the capital cost of one plant of this type. NF_{sij} denotes the number of standard
294 fueling stations of technology s , hydrogen form i , and size k . fcc_{sij} is the capital cost of one station
295 of this type. NF_{oj} gives the number of on-site fueling stations of technology o and size j . fcc_{oj}
296 is the capital cost of one station of this type. NR represents the number of CO₂ storage sites and
297 ccc is the capital cost of one site.

298 • CO₂ transportation capital cost (TCC)

299 The TCC is obtained by multiplying the unit capital cost of CO₂ pipeline ($cpcc$) by the pipeline
300 length:

$$TCC = cpcc * \sum_{n,m} X_{nm} * l_{nm} \tag{7}$$

301 where X_{nm} equals 1 if CO₂ is transported from node n to m , and l_{nm} is the shortest distance
302 between the two nodes.

303 4.2.2. Daily feedstock purchasing cost (EC)

$$EC = \sum_e ESR_e * euc_e \tag{8}$$

304 where euc_e is the unit cost of the feedstock of type e , and ESR_e is the total supply rate of the
305 feedstock of type e , given by

$$ESR_e = \sum_n (PESR_{ne} + OESR_{ne}) \tag{9}$$

306 where $PESR_{ne}$ is the supply rate of a feedstock site at node n that supplies feedstock of type e
307 to hydrogen production plants (plants at the same node or built at other nodes). $OESR_{ne}$ is the
308 feedstock supply rate of a feedstock site at node n that supplies feedstock of type e only to the
309 on-site fueling station built at the same node.

310 4.2.3. Daily operating cost (OC)

311 The operating cost (OC) includes the facility operating cost (FOC), the operating cost asso-
 312 ciated with hydrogen, and feedstock transportation ($HTOC$, $FTOC$):

$$OC = FOC + HTOC + FTOC \quad (10)$$

- 313 • Facility operating cost (FOC)

$$FOC = \sum_e NE_e * eoc_e + \sum_{p,i,k} PR_{pik} * poc_{pik} + \sum_{s,i,j} FR_{sij} * foc_{sij} + \sum_{o,j} FR_{oj} * foc_{oj} + CR * coc \quad (11)$$

314 where NE_e represents the number of feedstock supply sites that supply feedstock of type e to
 315 hydrogen production plants. eoc_e is the operating cost of one site of this type. PR_{pik} gives the
 316 total production rate of the production plants of technology p , hydrogen form i , and size k . poc_{pik}
 317 is the unit operating cost (per kg H₂) of this type of plant. FR_{sij} denotes the total fueling rate of
 318 standard fueling stations of technology s , hydrogen form i , and size j . foc_{sij} is the unit operating
 319 cost (per kg H₂) of this type of station. FR_{oj} represents the total fueling rate of on-site fueling
 320 stations of technology o and size j . foc_{oj} is the unit operating cost (per kg H₂) of this type of
 321 station. CR gives the total processing rate of CO₂. coc is the unit operating cost (per kg CO₂).

- 322 • Hydrogen transportation operating cost ($HTOC$)

$$HTOC = HFC + HLC + HMC + HGC + HRC \quad (12)$$

323 the five items on the right-hand-side are the fuel cost, labor cost, maintenance cost, general cost,
 324 and vehicle rental cost of hydrogen transportation, respectively. They are defined in Eqs. (13) -
 325 (17):

$$HFC = \sum_{h,n,m} fp_h * \frac{2 * l_{nm} * Q_{hnm}}{fe_h * tcap_h} \quad (13)$$

$$HLC = \sum_{h,n,m} dw_h * \frac{Q_{hnm}}{tcap_h} * \left(\frac{2 * l_{nm}}{sp_h} + lut_h \right) \quad (14)$$

$$HMC = \sum_{h,n,m} me_h * \frac{2 * l_{nm} * Q_{hnm}}{tcap_h} \quad (15)$$

$$HGC = \sum_{h,n,m} ge_h * \frac{Q_{hnm}}{tma_h * tcap_h} * \left(\frac{2 * l_{nm}}{sp_h} + lut_h \right) \quad (16)$$

$$HRC = \sum_h NV_h * tcr_h \quad (17)$$

326 In these equations, fp_h , dw_h , me_h , ge_h , and tcr_h represent the fuel price (per liter fuel), driver wage
 327 (per hour), maintenance expense (per km), general expense (per day), and vehicle rental cost (per
 328 vehicle) of hydrogen transportation mode h , respectively. fe_h , sp_h , $tcap_h$, tma_h , and lut_h denote
 329 the fuel economy, speed, capacity, availability (hours per day), and load/unload time of hydrogen
 330 transportation mode h , respectively. Q_{hnm} represents the hydrogen transportation flux (in mode
 331 h) from node n to m , and l_{nm} is the shortest distance between the two nodes. NV_h denotes the
 332 number of hydrogen transportation vehicles of mode h and is calculated by the following:

$$NV_h \geq \sum_{n,m} \frac{Q_{hnm}}{tma_h * tcap_h} * \left(\frac{2 * l_{nm}}{sp_h} + lut_h \right), \quad \forall h \in H \quad (18)$$

333 • Feedstock transportation operating cost (*FTOC*)

$$FTOC = FFC + FLC + FMC + FGC + FRC \quad (19)$$

334 The five items on the right-hand-side are the fuel cost, labor cost, maintenance cost, general cost,
 335 and vehicle rental cost of feedstock transportation, respectively. Their definitions have the same
 336 forms as those of the hydrogen transportation operating cost (Eqs. (13) - (17)).

337 4.2.4. Daily emission cost (*EMC*)

$$EMC = ER * cp \quad (20)$$

338 where cp is the carbon price and ER is the total emission rate, which is given by

$$ER = (PER - PER^c) + SFER + OFER + TER \quad (21)$$

339 PER is the production emission rate, which is obtained by

$$PER = \sum_{n,p,i,k} PR_{npik} * (\gamma_{pik}^{eu} + \gamma_{pik}^{eo}) \quad (22)$$

340 In the equation, PR_{npik} denotes the production rate of a production plant of technology p , hydrogen
 341 form i , and size k . γ_{pik}^{eu} and γ_{pik}^{eo} are the production upstream and on-site emission factors of this
 342 type of plant, respectively.

343 PER^c is the total emission rate of production plants where emissions are processed, given by

$$PER^c = \sum_n PER_n^c \quad (23)$$

344 where PER_n^c is the emission rate of a production plant at node n , where emissions are processed,
 345 given by

$$PER_n^c = \sum_{p,i,k} PR_{npik}^c * \gamma_{pik}^{eo} * \gamma_{pik}^c \quad (24)$$

346 where PR_{npik}^c represents the production rate of a production plant of technology p , hydrogen form
 347 i , and size k , and where emissions are processed (see Eq. (65)), and γ_{pik}^c is the production emission
 348 capture efficiency of this type of plant.

349 Fueling emission rates are obtained by Eqs. (25) and (26):

$$SFER = \sum_{s,i,j} FR_{sij} * \gamma_{sij}^e \quad (25)$$

$$OFER = \sum_{o,j} FR_{oj} * \gamma_{oj}^e \quad (26)$$

350 $SFER$ and $OFER$ are the total emission rates of the standard and on-site fueling stations, respec-
 351 tively. FR_{sij} represents the total fueling rate of standard fueling stations of technology s , hydrogen
 352 form i , and size j . γ_{sij}^e is the emission factor of this type of station. FR_{oj} denotes the total fueling
 353 rate of on-site fueling stations of technology o and size j . γ_{oj}^e is the emission factor of this type of
 354 station.

355 The emission rates related to hydrogen transportation (TER) depend on fuel usage, given by

$$TER = \sum_{h,n,m} \gamma_h^e * \frac{2 * l_{nm} * Q_{hnm}}{fe_h * tcap_h} \quad (27)$$

356 where γ_h^e is the emission factor of hydrogen transportation, which represents the volume of emissions
 357 due to the unit fuel usage. Q_{hnm} represents the hydrogen transportation flux (in mode h) from
 358 node n to m , and l_{nm} is the shortest distance between the two nodes. fe_h and $tcap_h$ are the fuel
 359 economy and capacity of hydrogen transportation mode h . The emissions results from feedstock
 360 transportation are included in the upstream emission of hydrogen production, therefore do not
 361 need to be calculated separately.

362 4.3. Constraints

363 4.3.1. Mass balance constraints

364 • Hydrogen

365 The hydrogen mass balance is defined at each node n , and for each hydrogen form i , such that the
 366 hydrogen production (PR_{npik}) and input from other nodes m (Q_{hmn}) meets the fueling demand
 367 (FR_{nsij}), the fixed-location demand ($dem_{ni}^{h,A}, dem_{ni}^{h,B}$) of this node n , and the hydrogen output to

368 other nodes m (Q_{hnm}), as follows:

$$\sum_{p,k} PR_{npik} + \sum_{h:(i,h) \in IH}^m Q_{hmn} = \sum_{h:(i,h) \in IH}^m Q_{hnm} + \sum_{s,j} FR_{nsij} + dem_{ni}^{h,A} + dem_{ni}^{h,B}, \quad (28)$$

$\forall n \in N, i \in I$

369 • Feedstock

370 For feedstock consumed by hydrogen production plants, the feedstock mass balance is defined at
 371 each node n , for each combination of feedstock types and production technologies (e, p) , such that
 372 the feedstock supply ($PESR_{ne}$) and input from other nodes m (Q_{fmn}) meets the consumption
 373 of feedstock, which is calculated by multiplying the production rate at that node (PR_{npik}) by
 374 the corresponding conversion rate ($\delta_{(e,p)}$), and the feedstock output to other nodes m (Q_{fnm}), as
 375 follows:

$$PESR_{ne} + \sum_{f:(e,f) \in EF}^m Q_{fmn} = \sum_{f:(e,f) \in EF}^m Q_{fnm} + \sum_{i,k} PR_{npik} * \delta_{(e,p)}, \quad (29)$$

$\forall n \in N, (e, p) \in EP$

376 For feedstock consumed by on-site fueling stations, the feedstock mass balance is given:

$$OESR_{ne} = \sum_j FR_{noj} * \delta_{(e,o)}, \quad \forall n \in N, (e, o) \in EF \quad (30)$$

377 In the equation, $OESR_{ne}$ represents the feedstock supply rate. FR_{noj} denotes the fueling rate and
 378 $\delta_{(e,o)}$ is the conversion rate of feedstock (type e) to hydrogen at on-site stations.

379 • CO₂

380 The CO₂ mass balance should be likewise satisfied at each node n to quantify the infrastructure
 381 needs for a CCS system.

$$PER_n^c + \sum_m Q_{mn} = \sum_m Q_{nm} + CR_n, \quad \forall n \in N \quad (31)$$

382 In the equation, PER_n^c represents the emission rate of a production plant at node n , where emis-
 383 sions are processed. Q_{mn} is the CO₂ transportation flux from node m to n , whereas Q_{nm} is the
 384 flux from node n to m . CR_n is the CO₂ processing rate.

385 4.3.2. Feedstock constraints

386 The feedstock supply rate ($PESR_{ne}$, $OESR_{ne}$) cannot exceed certain limits:

$$IE_{ne} * ecap_{ne}^{min} \leq PESR_{ne} \leq IE_{ne} * ecap_{ne}^{max}, \quad \forall n \in N, e \in E \quad (32)$$

$$IF_{no} * ecap_{ne}^{min} \leq OESR_{ne} \leq IF_{no} * ecap_{ne}^{max}, \quad \forall n \in N, (e, o) \in EO \quad (33)$$

$$PESR_{ne} + OESR_{ne} \leq ecap_{ne}^{max}, \quad \forall n \in N, e \in E \quad (34)$$

387 IF_{no} equals 1 if there is an on-site fueling station of technology o at node n , and is defined by

$$IF_{no} = \sum_j IF_{noj}, \quad \forall n \in N, o \in O \quad (35)$$

388 The number of feedstock supply sites that supply feedstock of type e to hydrogen production
389 plants (NE_e) is defined as

$$NE_e = \sum_n IE_{ne} \quad (36)$$

390 In Eqs. (32) - (36), IE_{ne} equals 1 if node n is chosen as a feedstock supplier (type e) of
391 production sites. IF_{noj} equals 1 if there is an on-site fueling station of technology o and size j at
392 node n . The bounds of feedstock supply capacity are denoted by $ecap$.

393 4.3.3. Production constraints

394 The production rate (PR_{npik}) cannot exceed certain limits:

$$IP_{npik} * pcap_{pik}^{min} \leq PR_{npik} \leq IP_{npik} * pcap_{pik}^{max}, \quad \forall n \in N, p \in P, i \in I, j \in K \quad (37)$$

395 The number of production plants (NP_{pik}) is given by

$$NP_{pik} = \sum_n IP_{npik} \quad (38)$$

396 The total production rate of production plants (PR_{pik}) is defined as

$$PR_{pik} = \sum_n PR_{npik} \quad (39)$$

397 In Eqs. (37) - (39), IP_{npik} equals 1 if there is a production plant at node n , of technology p ,
398 hydrogen form i , and size k . The bounds of production capacity are represented by $pcap$.

399 4.3.4. *Fueling station constraints*

400 The fueling rate (FR_{nsij} , FR_{noj}) cannot exceed certain limits:

$$IF_{nsij} * fcap_{sij}^{min} \leq FR_{nsij} \leq IF_{nsij} * fcap_{sij}^{max}, \quad \forall n \in N, s \in S, i \in I, j \in J \quad (40)$$

$$IF_{noj} * fcap_{oj}^{min} \leq FR_{noj} \leq IF_{noj} * fcap_{oj}^{max}, \quad \forall n \in N, o \in O, j \in J \quad (41)$$

401 The total fueling rates (FR_{sij} , FR_{oj}) are defined as

$$FR_{sij} = \sum_n FR_{nsij} \quad (42)$$

$$FR_{oj} = \sum_n FR_{noj} \quad (43)$$

402 The number of fueling stations (NF_{sij} , NF_{oj}) are given by

$$NF_{sij} = \sum_n IF_{nsij} \quad (44)$$

$$NF_{oj} = \sum_n IF_{noj} \quad (45)$$

403 In Eqs. (40) - (45), IF_{nsij} equals 1 if there is a standard fueling station at node n , of technology
404 s , hydrogen form i , and size j . IF_{noj} equals 1 if there is an on-site fueling station at node n , of
405 technology o and size j . The bounds of fueling capacity are denoted by $fcap$.

406 If fixed-location hydrogen demand of Type B exists at node n (means $id_n^{h,B}$ equals 1), a standard
407 fueling station should also be built at this node:

$$SIF_n \geq id_n^{h,B}, \quad \forall n \in N \quad (46)$$

408 SIF_n equals 1 if there is a standard fueling station at node n .

409 4.3.5. *Transportation constraints*

410 The transportation flux of hydrogen, feedstock, and CO₂ (Q_{hnm} , Q_{fnm} , Q_{nm}) cannot exceed
411 certain limits:

$$X_{hnm} * tcap_h^{min} \leq Q_{hnm} \leq X_{hnm} * tcap_h^{max}, \quad \forall h \in H, n, m \in N \quad (47)$$

$$X_{fnm} * tcap_f^{min} \leq Q_{fnm} \leq X_{fnm} * tcap_f^{max}, \quad \forall f \in F, n, m \in N \quad (48)$$

$$X_{nm} * tcap^{min} \leq Q_{nm} \leq X_{nm} * tcap^{max}, \quad \forall n, m \in N \quad (49)$$

412 In Eqs. (47) - (49), X_{hnm} , X_{fnm} , and X_{nm} are binary variables that take the value of 1 if
 413 transportation links are established from node n to m . The bounds of transportation capacity are
 414 represented by $tcap$.

415 Transportation between different nodes can only occur in one direction:

$$X_{hnm} + X_{hmn} \leq 1, \quad \forall h \in H, n, m \in N \quad (50)$$

$$X_{fnm} + X_{fmn} \leq 1, \quad \forall f \in F, n, m \in N \quad (51)$$

$$X_{nm} + X_{mn} \leq 1, \quad \forall n, m \in N \quad (52)$$

416 A node can only export hydrogen when there is a production plant at this node:

$$IP_n \geq X_{hnm}, \quad \forall h \in H, n, m \in N \quad (53)$$

417 where IP_n equals 1 if there is a production plant (of any technology, any hydrogen form, and any
 418 size) at this node. The following equation ensures that only one plant could be installed at each
 419 node.

$$IP_n = \sum_{p,i,k} IP_{npik}, \quad \forall n \in N \quad (54)$$

420 where IP_{npik} equals 1 if there is a production plant at node n , of technology p , hydrogen form i ,
 421 and size k .

422 Hydrogen is imported into the nodes that have standard fueling stations or fixed-location de-
 423 mand of Type A, or both:

$$SIF_n + id_n^{h,A} \geq X_{hnm}, \quad \forall h \in H, n, m \in N \quad (55)$$

424 where SIF_n equals 1 if there is a standard fueling station (of any technology, any hydrogen
 425 form, and any size) at this node. $id_n^{h,A}$ indicates whether node n has fixed-location demand of
 426 Type A.

427 A node cannot export feedstock when there is no feedstock supplier of hydrogen production
 428 plants (of any type of feedstocks) at this node (implies IE_n equals to 0):

$$IE_n \geq X_{fnm}, \quad \forall f \in F, n, m \in N \quad (56)$$

429 where IE_n is defined as

$$IE_n = \sum_e IE_{ne}, \quad \forall n \in N \quad (57)$$

430 where IE_{ne} equals 1 if node n is chosen as a feedstock supplier that supplies feedstock of type e to
 431 production plants.

432 The end of the feedstock transportation link can only be the production plants:

$$IP_n \geq X_{fnn}, \quad \forall f \in F, n, m \in N \quad (58)$$

433 where IP_n equals 1 if there is a production plant at node n .

434 A node can only export CO₂ when the emission of the production plant at this node is processed
 435 (means IM_n equals 1):

$$IM_n \geq X_{nm}, \quad \forall n, m \in N \quad (59)$$

436 The CO₂ transportation link ends only at the nodes where CO₂ storage sites are located (means
 437 IR_n equals 1):

$$IR_n \geq X_{mn}, \quad \forall n, m \in N \quad (60)$$

438 4.3.6. Emission constraints

439 The production emission of a node cannot be processed if there is no plant at this node:

$$IM_n \leq IP_n, \quad \forall n \in N \quad (61)$$

440 where IP_n denotes whether node n has a production plant, and IM_n takes the value of 1 if the
 441 emission of the plant at that node is processed.

442 The CO₂ processing rate (CR_n) cannot exceed certain limits:

$$IR_n * ccap_n^{min} \leq CR_n \leq IR_n * ccap_n^{max}, \quad \forall n \in N \quad (62)$$

443 where IR_n equals 1 if there is a CO₂ storage site at node n . The bounds of CO₂ processing capacity
 444 are represented by $ccap$.

445 The total processing rate of CO₂ (CR) is given by

$$CR = \sum_n CR_n \quad (63)$$

446 where CR_n is the CO₂ processing rate of a CO₂ storage site at node n .

447 The number of CO₂ storage sites (NR) is defined as

$$NR = \sum_n IR_n \quad (64)$$

448 The production rate of a production plant where emissions are processed (PR_{npik}^c) can be
449 obtained by the following equation:

$$PR_{npik}^c = IM_n * PR_{npik}, \quad \forall n \in N, p \in P, i \in I, k \in K \quad (65)$$

450 where PR_{npik} represents the production rate of a production plant at node n , and IM_n denotes
451 whether the emission of this plant is processed.

452 The Eq. (65) is nonlinear and can be linearized by the following constraints:

$$PR_{npik}^c \leq IM_n * pcap_{pik}^{max}, \quad \forall n \in N, p \in P, i \in I, k \in K \quad (66)$$

$$PR_{npik}^c \leq PR_{npik}, \quad \forall n \in N, p \in P, i \in I, k \in K \quad (67)$$

$$PR_{npik}^c \geq PR_{npik} - (1 - IM_n) * pcap_{pik}^{max}, \quad \forall n \in N, p \in P, i \in I, k \in K \quad (68)$$

453 where $pcap_{pik}^{max}$ is the upper limit of production capacity.

454 4.3.7. Demand constraints

455 The percentage of hydrogen fueling demand flow that can be captured ($DEM^{h,cap}$) should be
456 equal to the number given as input ($dem^{h,exp}$):

$$DEM^{h,cap} = dem^{h,exp} \quad (69)$$

457 Because hydrogen fueling demand flow of OD (Origin–Destination) flow pairs are discrete val-
458 ues, the following constraints to replace the Eq. (69) are introduced:

$$dem^{h,exp} \leq DEM^{h,cap} \leq dem^{h,exp} + \epsilon \quad (70)$$

459 where ϵ is a small positive number, which is set to 0.01 in this study, and $DEM^{h,cap}$ is defined by

$$DEM^{h,cap} = \frac{\sum_q f_q^{pair} * IC_q}{\sum_q f_q^{pair}} * 100 \quad (71)$$

460 where f_q^{pair} is the amount of hydrogen fueling demand flow of OD flow pair q , and IC_q equals 1 if
461 flow pair q is captured.

462 A hydrogen fueling demand flow is captured if there is at least one fueling station (of any
 463 technology and any size) on one of the nodes that lie on the shortest path of this flow pair:

$$\sum_{n \in N_q} IF_n \geq IC_q, \quad \forall q \in Q, \quad (72)$$

464 where IF_n equals 1 if there is a fueling station (standard or on-site) at this node. The following
 465 equations ensure that only one fueling station could be installed at each node.

$$IF_n = SIF_n + OIF_n, \quad \forall n \in N \quad (73)$$

$$SIF_n = \sum_{s,i,j} IF_{nsij}, \quad \forall n \in N \quad (74)$$

$$OIF_n = \sum_{o,j} IF_{noj}, \quad \forall n \in N \quad (75)$$

466 where SIF_n equals 1 if there is a standard fueling station at node n , and OIF_n equals 1 if there
 467 is an on-site fueling station at this node. IF_{nsij} equals 1 if there is a standard fueling station at
 468 node n , of technology s , hydrogen form i , and size j . IF_{noj} equals 1 if there is an on-site fueling
 469 station at node n , of technology o and size j .

470 The fueling rate at node n (FR_{nsij}, FR_{noj}) should be able to cover the amount of hydrogen
 471 fueling demand flow captured by the fueling station established at that node:

$$\sum_{s,i,j} FR_{nsij} \geq SIF_n * f_n^{node}, \quad \forall n \in N \quad (76)$$

$$\sum_{o,j} FR_{noj} \geq OIF_n * f_n^{node}, \quad \forall n \in N \quad (77)$$

472 where f_n^{node} is the hydrogen fueling demand flow of node n .

473 5. Case study: Franche-Comté, France

474 The developed model is applied to Franche-Comté, a region of eastern France (since 2016, it
 475 is part of the new region Bourgogne-Franche-Comté.). Its total area is 16,202 km². In 2016, its
 476 population was 1,180,397 persons.

477 5.1. Network description

478 The 31 most populous cities are selected as network nodes. Demographic data of each city
 479 are collected based on the *commune*¹ in which the city is located. The most populous city is

¹The commune is a level of administrative division in France.

480 Besançon, the capital of the region. There are several large cities in the northeast, including Belfort,
481 Montbéliard and Valentigney. Other major cities include Vesoul in the north, Dole in the west, and
482 Pontarlier in the south. The main roads (including auto-routes, national roads, and departmental
483 roads) connecting the cities are selected as network edges. There are 65 edges. Length data are
484 acquired from Google MapsTM. The length of the network’s edges and the distances between
485 different cities are given in the supplementary material. The network generated is presented in
486 Fig. 2 - (a).

487 Three types of feedstock are considered in this study: natural gas, electricity, and biomass.
488 Natural gas can be supplied only in cities that are covered by the natural gas network. According
489 to GRTgaz (2017, 2019)², 23 cities have access to the natural gas network, as shown in Fig. 2 - (b).
490 The maximum supply capacity of natural gas is fixed at 30,000 Nm³/d. Electricity is available in
491 all cities (see Fig. 2 - (c)). The maximum supply capacity is fixed at 300,000 kWh/d. It is assumed
492 that two cities (Luxeuil-les-Bains in the north and Valdahon in the center) could supply biomass,
493 and the maximum supply capacity is fixed at 70,000 kg/d. The feedstock prices are shown in Table
494 B.8.

495 It is assumed that a potential CO₂ storage site is located at Morteau and its maximum pro-
496 cessing capacity is 200,000 kg CO₂/d (see Fig. 2 - (d)). Other CCS system inputs can be found in
497 Table B.8. It is also assumed that the fixed-location demand of Type A exists at Saint-Claude, the
498 amount of hydrogen demand is 500 kg/d. Fixed-location demand of Type B exists at Pontarlier,
499 the amount of demand is 500 kg/d (see Fig. 2 - (e)).

500 5.2. Hydrogen fueling demand

501 The proposed model satisfies two major types of hydrogen demand: fixed-location demand
502 (node-based) and fueling demand of FCEVs (flow-based). This section explains how the fueling
503 demand of FCEVs is represented by the flow-based demand. The classical Flow-Capturing Location
504 Model (FCLM) defines only the locations of the service facilities. Decision-makers receive no
505 references on the required service capacity to satisfy part or all of the “flow captured”. It is evident
506 that the relationship between the “flow captured” and the service capacity should be built before
507 the capacity-related decision variables are introduced into the model. In the context of fueling
508 station deployment, such a relationship is often established between the fueling demand and the
509 road traffic flow. The underlying assumption is that all units of traffic flow within the region
510 (between different origins and destinations) contribute equally to the fueling demand. Considering
511 most of the vehicles on the road still rely on gasoline or diesel, this assumption is reasonable when
512 deploying traditional fueling stations. However, this same assumption becomes questionable when
513 the problem has been changed to hydrogen fueling station planning. It is mainly due to uneven
514 distribution of FCEVs within the region’s traffic flow. Therefore, the concept of hydrogen fueling

²GRTgaz is a French natural gas transmission system operator.

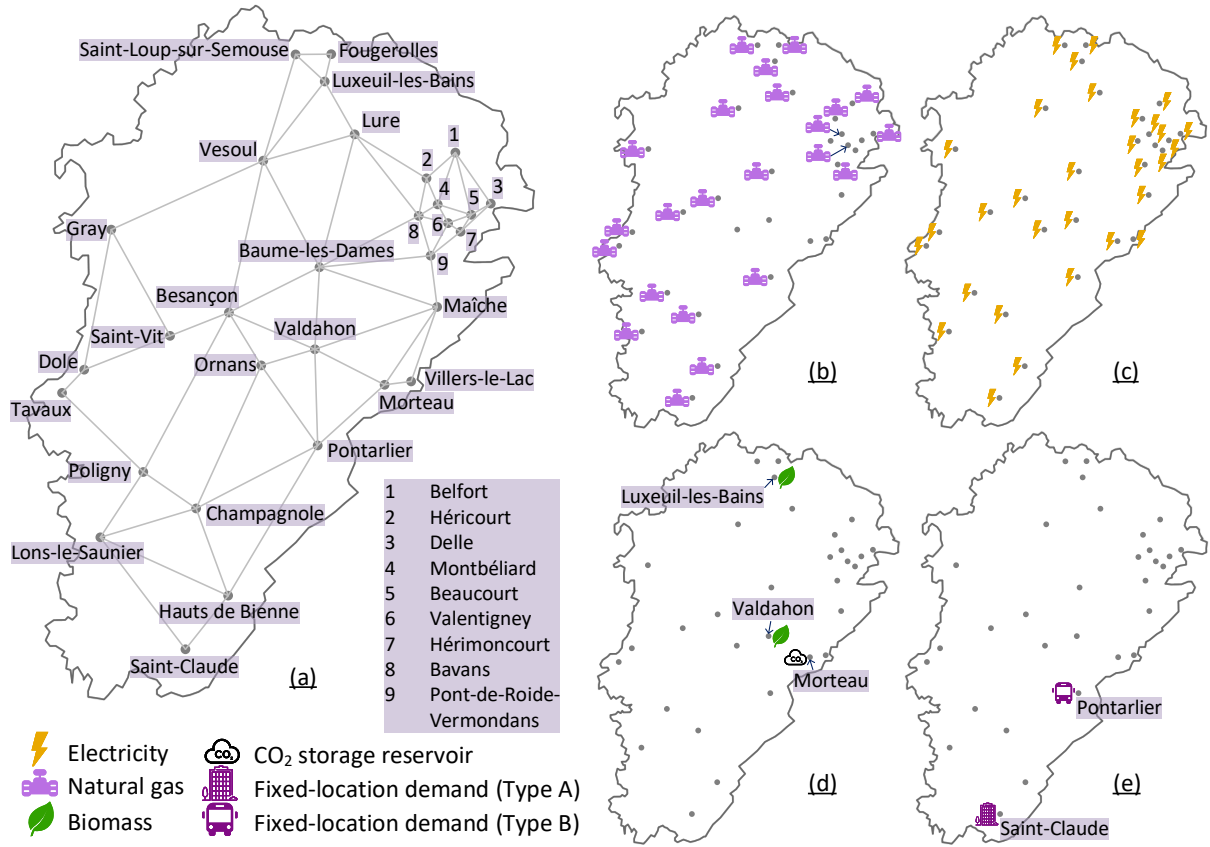


Figure 2: Franche-Comté network: (a) Basic network; (b) Natural gas distribution; (c) Electricity distribution; (d) Biomass distribution and location of a potential CO₂ storage site; (e) Location of fixed-location demands

515 demand flow is introduced, which is a modified traffic flow that involves the influences of potential
 516 FCEV owner-ships in different cities or towns. The fueling capacity of a hydrogen fueling station
 517 is therefore defined by the hydrogen fueling demand flow that has been captured by the station.

518 It is assumed that hydrogen fueling demand flow is more likely to appear between two closer
 519 cities with higher FCEV owner-ships. The potential FCEV ownership is related not only to the
 520 population but also to several demographic metrics. Melendez & Milbrandt (2008) proposed nine
 521 metrics that influence FCEV adoption by consumers. Given the availability of statistics, the
 522 following four are chosen for this study:

- 523 • *Vehicle*³: Households with multiple vehicles are more likely to adopt hydrogen vehicles.
- 524 • *Income*⁴: Higher incomes lead to earlier adoption of FCEV.

³The ratio of households with two or more vehicles.

⁴Yearly household income.

- 525 • *Education*⁵: Higher education leads to earlier adoption.
- 526 • *Commute*⁶: Commuting with private vehicles interests consumers in newer and more efficient
- 527 vehicles.

528 Table B.1 provides the population size and four demographic metrics for each city. Data are
 529 collected from L’Institut national de la statistique et des études économiques (2015a,b, 2018a,b)⁷.

530 Considering all five factors, a “scoring system” similar to the one used by Melendez & Milbrandt
 531 (2006) is employed. In the “scoring system”, data in each column are first normalized in the range
 532 of 1-100 to compute the score of each city on each item:

$$Score_x = 1 + 99 * \frac{Value_x - Value_{min}}{Value_{max} - Value_{min}} \quad (78)$$

533 Then the final score of each city is obtained by a linear combination of the five obtained scores,
 534 as shown in Eq. (79). The weights are chosen according to the importance of each metric.

$$Score_{final} = Score_{Population} * 0.6 + Score_{Vehicle} * 0.1 + Score_{Income} * 0.1 \quad (79)$$

$$+ Score_{Education} * 0.1 + Score_{Commute} * 0.1$$

535 The final score represents the relative potential FCEV ownership of each city. If one considers
 536 the final score as the *weight* of each city, then a network with weight values of cities could be
 537 obtained, as presented in Fig. 3 - (a). The radius of circles at nodes is visually proportional to
 538 these weights. The plot of Fig. 3 - (b) is the weighted network based only on population. It can
 539 be seen that after considering the influence of the four additional demographic metrics, some cities
 540 with smaller populations have gained greater weight. For example, Villers-le-lac has the highest
 541 score of “Income”, Gray has the highest score of “Vehicle”, and Bavans has higher scores in both
 542 “Vehicle” and “Commute”. It can also be found that, although Besançon is still the city with
 543 the largest weight, the urban agglomerations in the northeast have gathered several cities with
 544 relatively high weights.

545 After computing the demand level for the 31 considered cities, the potential flow of FCEVs on
 546 the roads of the network should be determined. First, the gravity model (Haynes & Fotheringham,
 547 1985) is used to quantitatively measure the possibility that an OD pair flow becomes a hydrogen
 548 fueling demand flow. As shown in Eq. (80), the possibility (P_q) of an OD pair (q) that links two
 549 cities n and m can be expressed as a ratio of the multiplied final scores (weights of cities obtained

⁵Share of persons whose highest degree is a bachelor’s degree in the out-of-school population aged 15 or over.

⁶Share of persons who use private vehicles for commuting.

⁷National Institute of Statistics and Economic Studies

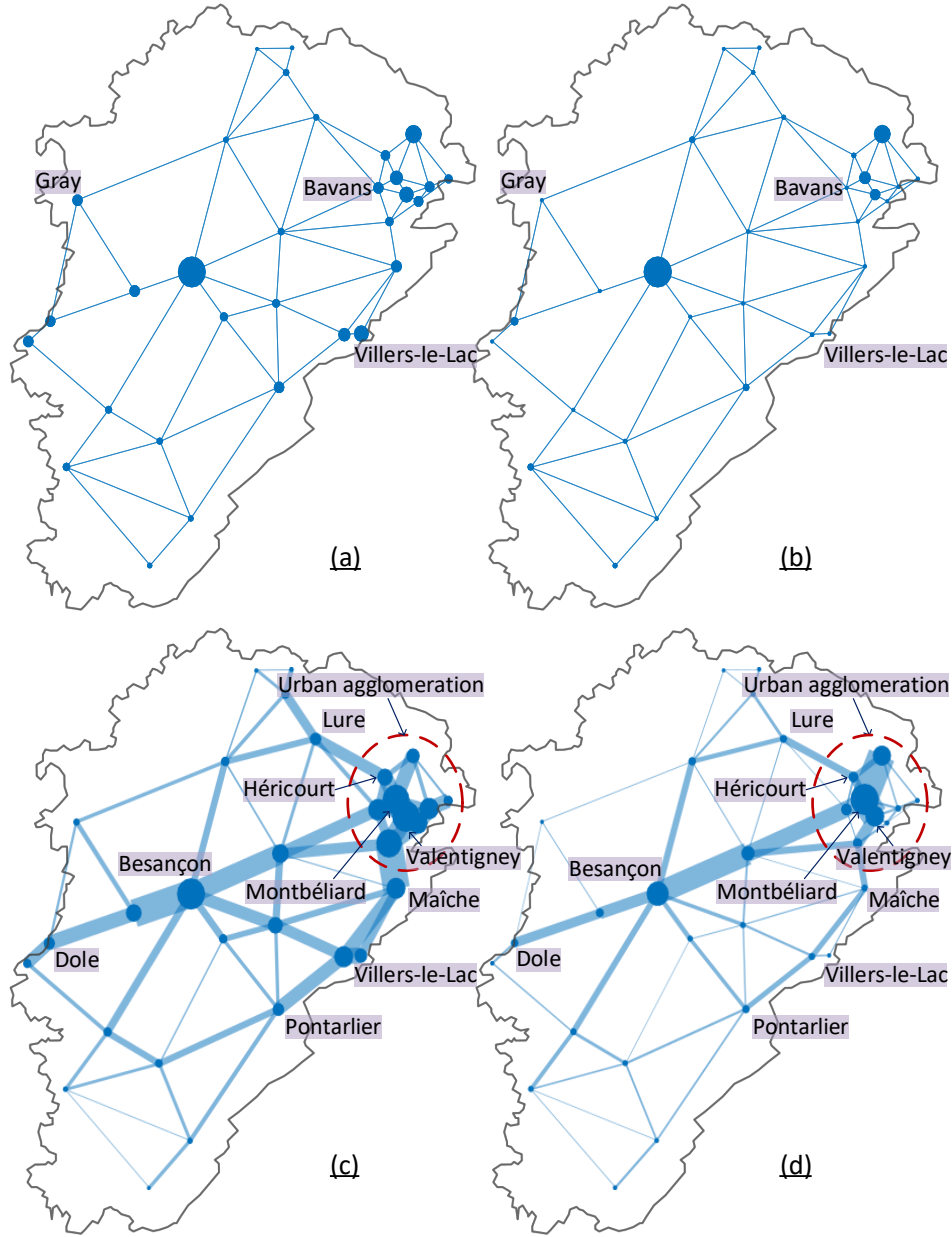


Figure 3: Hydrogen fueling demand flow: (a) Weighted network; (b) Weighted network based only on population; (c) Hydrogen fueling demand flow network; (d) Hydrogen fueling demand flow network based only on population

550 above) over the distance between any pair of cities.

$$P_q = \frac{Score_{final,city_n} * Score_{final,city_m}}{l_{nm}} \quad (80)$$

551 The obtained results can be regarded as “weights” of origin–destination (OD) pairs, with which

552 the value of hydrogen fueling demand flow of each pair is determined. Based on the report of
553 L'Association Française pour l'Hydrogène et les Piles à Combustible (2018)⁸, it is estimated that
554 the potential hydrogen demand of FCEV in Franche-Comté in 2030 will be 4,378 kg/d⁹. This total
555 demand is distributed to OD pairs according to their “weights” obtained by Eq. (80). In this way,
556 the hydrogen fueling demand is linked to the OD flow pairs, and the resulting demand flow network
557 is presented in Fig. 3 - (c). The larger the radius of the circle, the higher the fueling demand in
558 the city. The wider the edge, the greater the fueling demand flow carried by that edge. Comparing
559 this flow network with the one based only on population (Fig. 3 - (d)), the common element is
560 the region’s east-west traffic artery–A36 (Montbéliard-Besançon-Dole), which carries the largest
561 hydrogen fueling demand in both networks. However, one observes the following differences:

- 562 • The hydrogen fueling demand flow between the eastern urban agglomerations has increased
563 significantly. This can be explained as follows: According to the gravity model, greater weight
564 and closer distance result in larger interaction. The urban agglomerations formed by several
565 cities with large weights have reasonably more interactions with each other.
- 566 • In the east, the flow through Lure, Héricourt, Valentigney, Maïche, Pontarlier has increased
567 significantly. This can be explained by the fact that small cities like Villers-le-lac, Maïche,
568 and Bavans have higher weights.

569 5.3. Hydrogen supply network

570 5.3.1. Production plants

571 Corresponding to three types of feedstock, three types of production technologies are set up:
572 steam methane reforming (SMR), electrolysis, and biomass gasification (BG). The production plant
573 has three sizes (small, medium, and large), with production capacity ranging from 1,000 kg/d to
574 5,000 kg/d. Each type of plant has sets of data for the production of gaseous hydrogen and liquid
575 hydrogen. Data are collected mainly from the Hydrogen Analysis (H2A) project conducted by
576 the U.S. Department of Energy (Department of Energy, 2010, 2018b,c,d). Tables B.2, B.3, and
577 B.4 present the capital cost, operating cost, production capacity, emission factor, and emission
578 capture efficiency for each type of production technology. Attention has been directed to use the
579 local emission factor of electricity that is obtained from the Électricité de France (2018)¹⁰. The
580 conversion rates of production technologies can be found in Table B.8.

⁸The French Association for Hydrogen and Fuel Cells

⁹The report provides only the total hydrogen demand of FCEV in France in 2030 (89,000 kg/d). The value for Franche-Comté is obtained by multiplying the total demand with the proportion of province (Franche-Comté) population to France population (1.80% (L’Institut national de la statistique et des études économiques, 2015b))

¹⁰A French electric utility company

581 *5.3.2. Fueling stations*

582 The fueling capacity ranges from 50 kg/d to 1,200 kg/d, divided into four sizes - small, medium,
 583 large, and extra-large¹¹. Standard fueling stations are divided into two subtypes according to the
 584 hydrogen form they receive, and the cost and emission data are shown in Table B.5. The on-site
 585 fueling stations consist of on-site-SMR and on-site-electrolysis. The cost and emission data are
 586 presented in Table B.6 (Melaina & Penev, 2013).

587 *5.3.3. Hydrogen and feedstock transportation*

588 Gaseous hydrogen is conveyed via tube trailers whereas liquefied hydrogen is transported in
 589 tanker trucks. For feedstock, this study considers only the transportation of biomass via trucks.
 590 The cost and emission data are presented in Table B.7.

591 *5.4. Instances generation*

592 One of the primary purposes of this study is to demonstrate the necessity of considering various
 593 components within a single framework. The influence of any component on the HSCN can be
 594 identified only by comparing and analyzing the model results with and without this component.
 595 Based on this principle, seven groups of instances have been designed, each of which corresponds
 596 to a component composition, as shown in Table 2.

Table 2: Groups of instances

	Model components				
	On-site station	Standard station	Feedstock transportation	CCS system	Fixed-location demand
Group A	✓				
Group B		✓			
Group C	✓	✓			
Group D		✓	✓		
Group E		✓		✓	
Group F		✓			✓
Group G	✓	✓	✓	✓	✓

- 597 • *Group A:* Only on-site stations are used to satisfy fueling needs. This can be seen as a simple
 598 upgrade of the classical FCLM (Flow-Capturing Location Model). The main mission is to
 599 locate on-site stations under the constraints of feedstock availabilities. In addition, the model
 600 needs to select a proper size for each on-site station.
- 601 • *Group B:* Only standard stations are employed to satisfy fueling needs. The model needs to
 602 locate standard stations as well as production plants, as the former can only receive hydrogen

¹¹The fueling capacity of “extra-large” stations is twice that of “large” ones

603 produced by the latter. In this group of instances, feedstock transportation is forbidden.
604 Therefore, a plant can use only the feedstock supplied by the city where it is located. Plants
605 and standard stations are linked by hydrogen transportation. Group B integrates the HSCND
606 model and the HFSP model, and covers the whole hydrogen supply chain, from feedstock to
607 fueling stations.

608 • *Group C*: Based on Group B, with the addition of on-site stations. The introduction of on-site
609 stations allows the model to choose between two completely different fueling technologies. It is
610 reasonable to assume that “mix” may provide more interesting configurations. By comparing
611 the results of instances of Group A, Group B, and Group C, one could learn how fueling
612 technologies impact HSCN.

613 • *Group D*: Based on Group B, but allowing feedstock transportation. The introduction of
614 feedstock transportation provides the model with the capability to examine the trade-off
615 between the transportation of feedstock and hydrogen. By comparing the results of instances
616 of Group B and Group D, one examines the necessity of integrating feedstock transportation
617 into the model.

618 • *Group E*: Based on Group B, and involving a CCS system. Although the adoption of a
619 CCS system could greatly reduce the CO₂ emission of HSCN, it yields huge expenses. The
620 introduction of a CCS system makes the model capable of studying the trade-off between
621 considerable emission costs and establishment of a CCS system. In addition, the model
622 examines the trade-off among the transportation of hydrogen, feedstock, and CO₂ when
623 locating production plants. By comparing the results of instances of Group B and Group E,
624 one reviews the necessity of integrating a CCS system into the model.

625 • *Group F*: Based on Group B, adding fixed-location demand. The purpose of this group is
626 to verify that the model can meet other hydrogen demand requirements while satisfying the
627 fueling demands. By comparing the results of instances of Group B and Group F, one can
628 observe how fixed-location demand changes the configuration of HSCN.

629 • *Group G*: All model components are involved. The model will be able to compare all possible
630 configurations together and to consider various trade-offs to find the optimal result.

631 Within each group of instances, one or several sets are defined. The sets of a given group differ
632 by the feedstock type or the hydrogen form, as shown in Table 3.

633 The model proposed in this study is mono-objective. The environmental impact of the HSCN
634 is represented by the contribution of emission cost in the LCOH. Therefore, the value of the carbon
635 price has a significant influence on the model results. Two levels of carbon price are set to observe
636 the changes in configuration, especially the model’s behavior toward a CCS system. Based on the

Table 3: Sets of instances within each group

	Feedstock			Hydrogen form	
	Electricity	Natural gas	Biomass	Gaseous	Liquid
Set A1	✓			N/A	N/A
Set A2		✓		N/A	N/A
Set B1		✓		✓	
Set B2		✓			✓
Set B3			✓	✓	
Set C		✓		✓	
Set D			✓	✓	
Set E1		✓		✓	
Set E2			✓	✓	
Set F		✓		✓	
Set G	✓	✓	✓	✓	✓

estimation of carbon price in Europe from various institutions (Carbon Tracker, 2018; Chestney, 2018; World Bank & Ecofys, 2018), the low level of carbon price (LC) is set to 0.05 €/kg CO₂, and the high level (HC) is set to 0.27 €/kg CO₂.

The potential hydrogen fueling demand is represented by “flow”. It may not necessarily be “captured” totally. Decision-makers can decide freely the percent of flow that needs to be captured. For a specific percent of flow, the model provides the optimal HSCN configuration that satisfies these demands and the resulting LCOH. Fig. 4 presents the value of LCOH and number of fueling stations for each percent of flow captured of Set A1 with LC (low carbon price), from 1% to 100%. It can be seen that the LCOH curve appears U-shaped. A small fueling demand flow requires at least one station to be satisfied. Therefore, the contribution of capital cost to LCOH will be extremely high. Thus, for less than 10%, the smaller the percentage of flow captured, the higher the LCOH. At the other end, greater than 90%, the model needs to build more stations to approach 100%. This is because the places that are more efficient in flow capturing have already been chosen. The “extra” expenditure in capital cost causes the curve to rise sharply. For decision-makers, less than 10% and higher than 90% are areas of less interest. Therefore, three levels of fueling demand are set, 10% for low demand (LD), 50% for medium demand (MD), and 90% for high demand (HD). Then one can generate 66 instances. The name of each instance is formatted as “Set-N-C-D”, where “N” is the name of 11 sets defined in Table 3, “C” is the carbon price level (LC or HC), and “D” represents the fueling demand level (LD, MD, or HD). Each instance is solved to obtain its value of LCOH and network configuration. Fig. 5 illustrates the configuration and captured hydrogen fueling demand flow of Set-A1-LC-MD. It is shown that three on-site stations are located at Besançon, Champagnole, and Valentigney. The captured flow is indicated in red. Based on the model’s assumptions, a fueling station could capture all fueling demand of the node at which it is located. Correspondingly, all edges’ flow directly linked to this node is also captured. This explains

661 why the three cities and their surrounding roads are all red. Flows in areas with no stations are
 662 less captured, as in the northern area. All instances analyzed in the following section have this
 663 kind of figure to provide a visual representation of the captured hydrogen fueling demand flow.

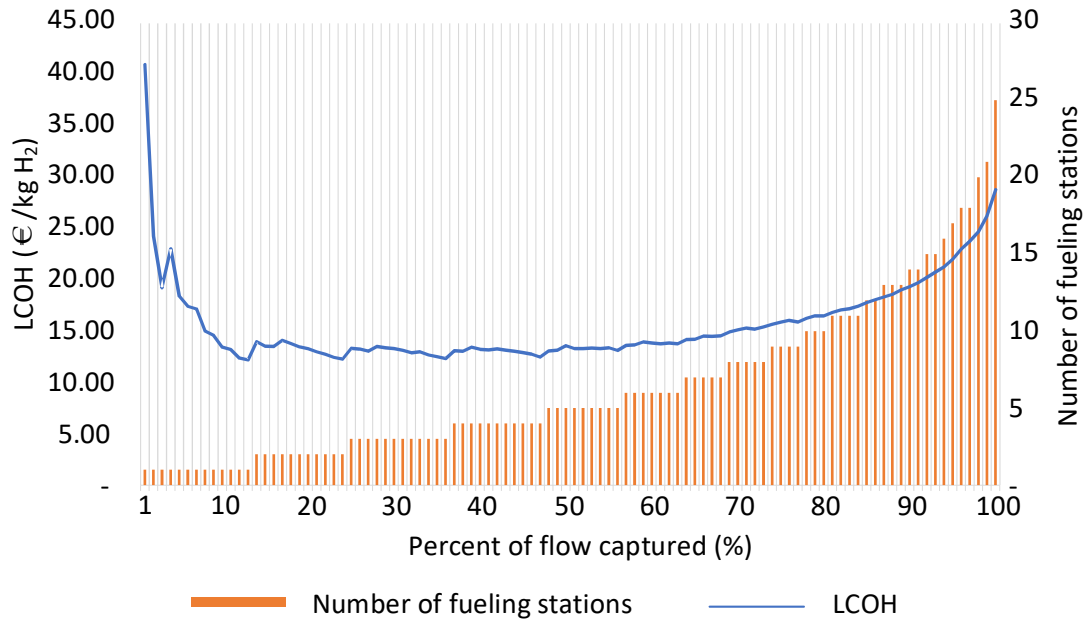


Figure 4: The value of LCOH and number of fueling stations for each percent of flow captured of Set A1 with LC (low carbon price), from 1% to 100%

664 **6. Results and discussion**

665 The model is solved by CPLEX 12.7 for the defined instances on a computer equipped with a
 666 3.2 GHz i5-6500 and 16 GB of RAM. The corresponding computational statistics are summarized
 667 in Table 4. Fig. 6 provides a comparison of the results obtained in terms of LCOH. Detailed results
 668 of 66 instances are presented in the supplementary material.

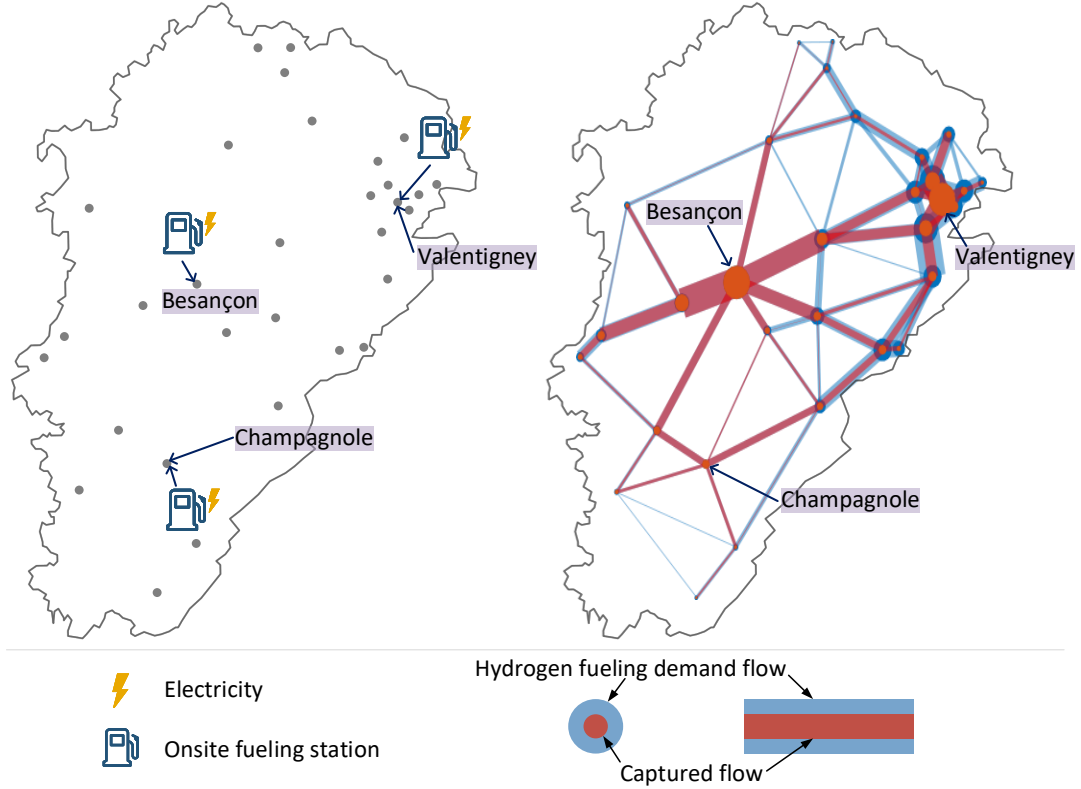


Figure 5: Configuration and captured hydrogen fueling demand flow of Set-A1-LC-MD

Table 4: Size of the instances

Instance group	A	B	C	D	E	F	G
Number of constraints	932	10,761	11,226	15,598	15,969	11,722	24,526
Number of binary variables	682	2,728	2,914	3,720	3,751	2,728	5,735
Number of integer variables	-	2	2	3	2	2	3
Number of continuous variables	155	2,170	2,325	3,131	3,255	2,170	5,673
Maximum CPU time (s)	1	7,567	16	407	144	11	539

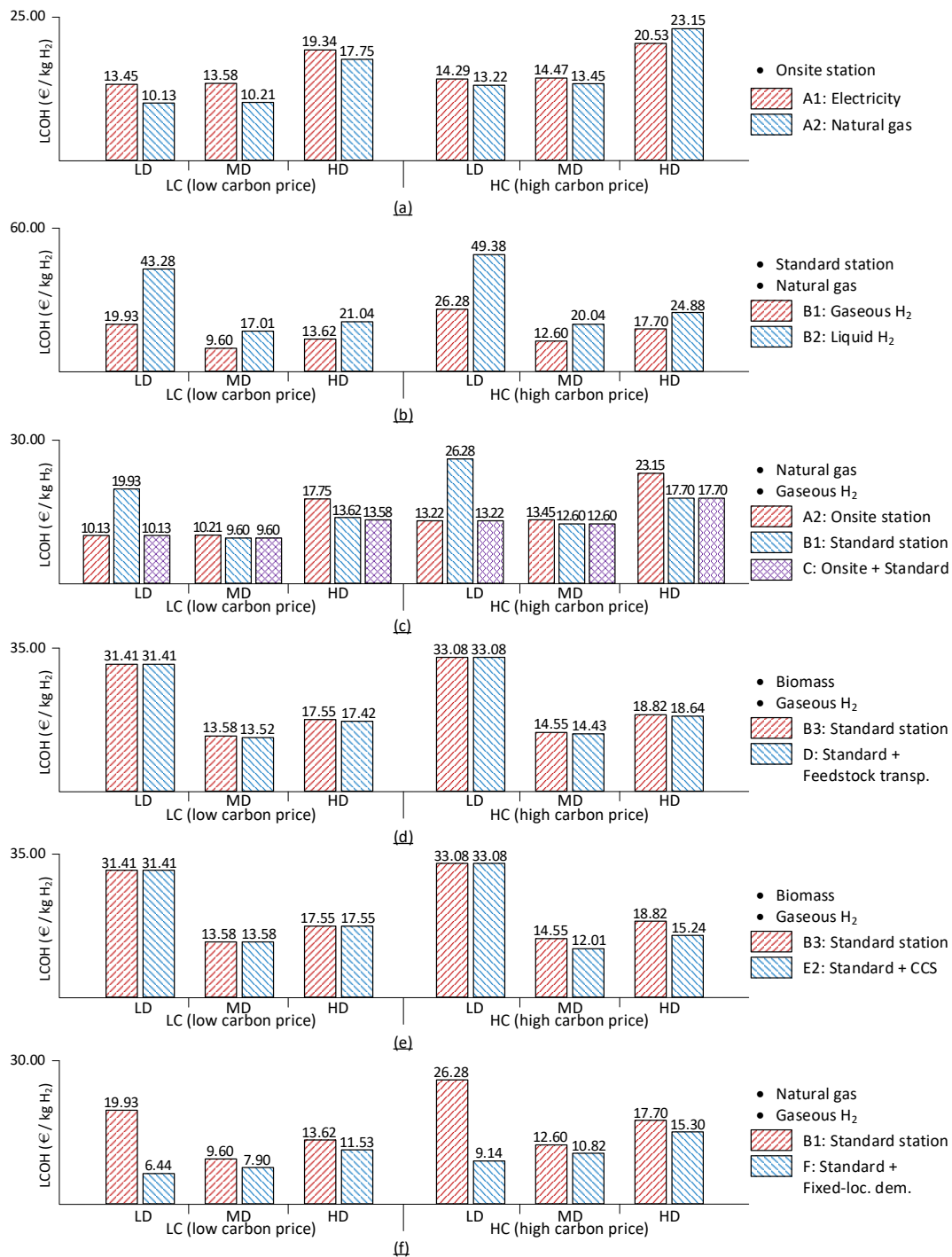


Figure 6: Obtained LCOH: (a) Set A1 vs. Set A2; (b) Set B1 vs. Set B2; (c) Set A2 vs. Set B1 vs. Set C; (d) Set B3 vs. Set D; (e) Set B3 vs. Set E2; (f) Set B1 vs. Set F

669 *6.1. Role of feedstock availabilities*

670 It is known that on-site-electrolysis stations have a higher capital cost than on-site-SMR, as
671 shown in Table B.6. Therefore, in most situations, instances of Set A1 obtain a higher LCOH than
672 instances of Set A2 (see Fig. 6 - (a)). As the emission factor of on-site-SMR is higher than that
673 of on-site-electrolysis, the impact of emission costs will be more important as the carbon price is
674 high. The gap between the two sets shrinks when carbon price increases, and this gap may even
675 reverse for instances A_i-HC-HD.

676 Fig. 7 illustrates the differences between the supply chain structures obtained with the model
677 for Set A1 and A2. Only the results for the high carbon price scenario are presented here. For the
678 two sets of instances, one obtains the same number and locations of on-site stations at low and
679 medium demands. It must be noted that Set A2 can only install on-site-SMR stations at cities
680 that are covered by a natural gas network, which means that the model cannot locate stations
681 considering only the efficiency of fueling demand flow capturing. Consequently, at high demand,
682 Set A2 results in more stations and higher LCOH than Set A1.

683 *6.2. Role of hydrogen forms*

684 Fig. 6 - (b) shows that HSCN based on liquid hydrogen is more expensive at all three demand
685 levels. The high cost is due to the need for liquefaction devices, which incur a high capital cost.
686 Moreover, liquefaction requires a large amount of power consumption, increasing operating costs.
687 Notice the gap between gaseous and liquid is shrinking when hydrogen demand rises. This can be
688 explained by the advantage of liquid hydrogen in transportation. The number of vehicles required
689 to transport the same amount of liquid hydrogen is smaller than for gaseous hydrogen because
690 the capacity of a tanker truck (for liquid hydrogen) is nearly 23 times as large as a tube trailer
691 (for gaseous hydrogen). Although the advantage in transportation cannot offset the high cost of
692 liquefaction at low demand (i.e., when only a small number of vehicles are required), HSCN based
693 on liquid hydrogen may be attractive when the demand of hydrogen increases.

694 In Fig. 8, one observes that, at medium and high demand, results for Set B2 involve fewer
695 plants, and are more dependent on hydrogen transportation. This can reduce the disadvantages
696 of high costs of liquefaction and take advantage of transportation. Therefore, it can be concluded
697 that HSCN based on liquid hydrogen prefers centralized production.

698 *6.3. Role of fueling technologies*

699 First, observe Set A2 (on-site station only) and Set B1 (standard station only) in Fig. 6 - (c).
700 It is shown that at low demand, Set B1 has higher LCOH. Indeed, any standard station requires to
701 be supplied by a production plant, which increases the cost. At medium demand, the advantage of
702 centralized production makes Set B1 reach lower LCOH than Set A2, and this advantage is even
703 more obvious at high demand. The involvement of different fueling technologies provides the model

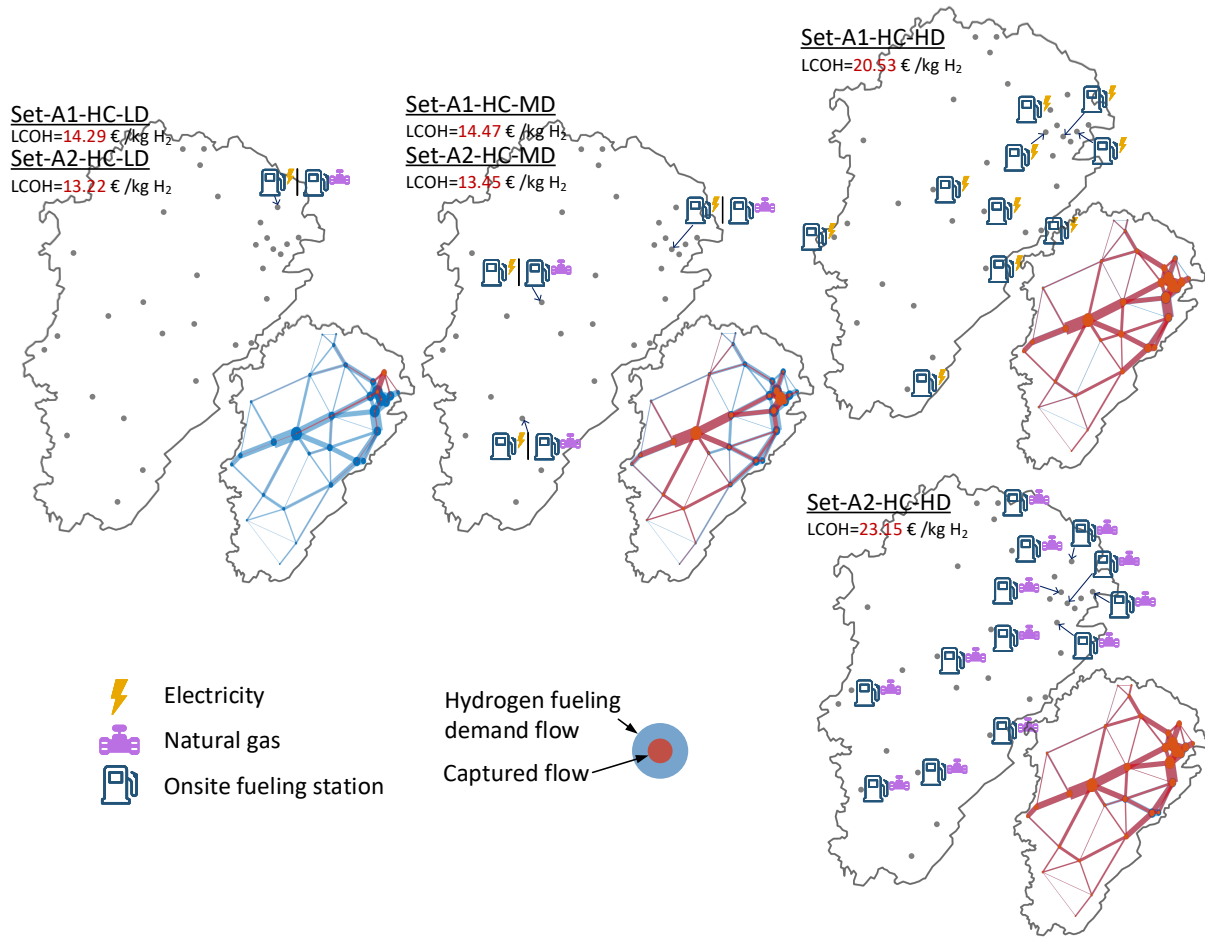


Figure 7: Configurations of Set A1 and A2 with high carbon price

704 with the ability to consider the trade-off between a centralized solution (with standard stations)
 705 and a decentralized configuration (with on-site stations).

706 It is reasonable to assume that “mix” could bring even better results (lower LCOH), and Set C
 707 is therefore introduced, as shown by the obtained solutions illustrated in Fig. 9. At low demand,
 708 Set C has the same configuration and LCOH as Set A2. At medium demand, Set C has the same
 709 results as Set B1. At high demand, Set C obtains the lowest LCOH. Although the instance Set-
 710 C-LC-HD has the same number of fueling stations as Set-B1-LC-HD, the former achieves lower
 711 LCOH by adopting both on-site and standard stations. In Set-C-LC-HD, the model chooses to
 712 install an on-site station at Champagnole. The introduction of an on-site station reduces the
 713 demand for hydrogen produced by production plants. Therefore Set-C-LC-HD has one less plant
 714 than Set-B1-LC-HD. Although these structural changes result in only a slight drop in LCOH, it
 715 proves that it is indeed possible to find a supply chain configuration with lower LCOH by allowing
 716 the model to consider both fueling technologies. Notice that in high carbon price scenarios, Set C

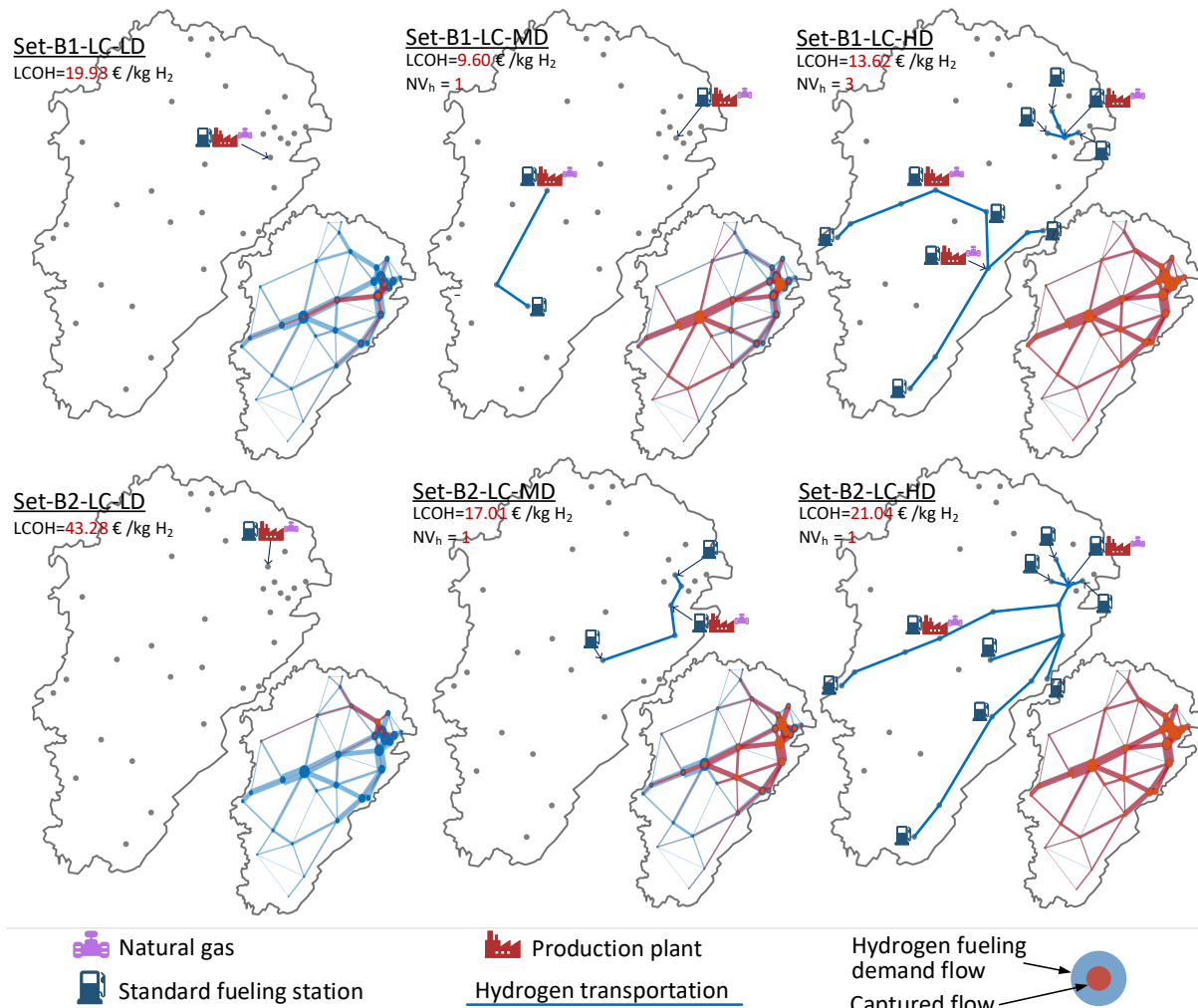


Figure 8: Configurations of Set B1 and B2 with low carbon price

717 and Set B1 have the same LCOH and configuration at high demand. The reason why Set C does
 718 not choose a “mix” solution in the high carbon price scenario can be explained by the fact that
 719 the emission factor of on-site-SMR is approximately seven times greater than the gaseous standard
 720 station emission factor. Therefore on-site stations are less attractive when carbon price rises.

721 6.4. Role of feedstock transportation

722 For this part, high carbon price does not bring changes in configuration (Fig. 6 - (d)). Only the
 723 results for low carbon price are discussed. Notice that at low demand, one obtains the same LCOH
 724 for Set D and B3. At medium and high demand, one obtains slightly different values of LCOH. That
 725 is because Set D uses feedstock transportation, and therefore finds lower LCOH. The comparison of
 726 Set-D-LC-HD and Set-B3-LC-HD serves as a good example to show how feedstock transportation

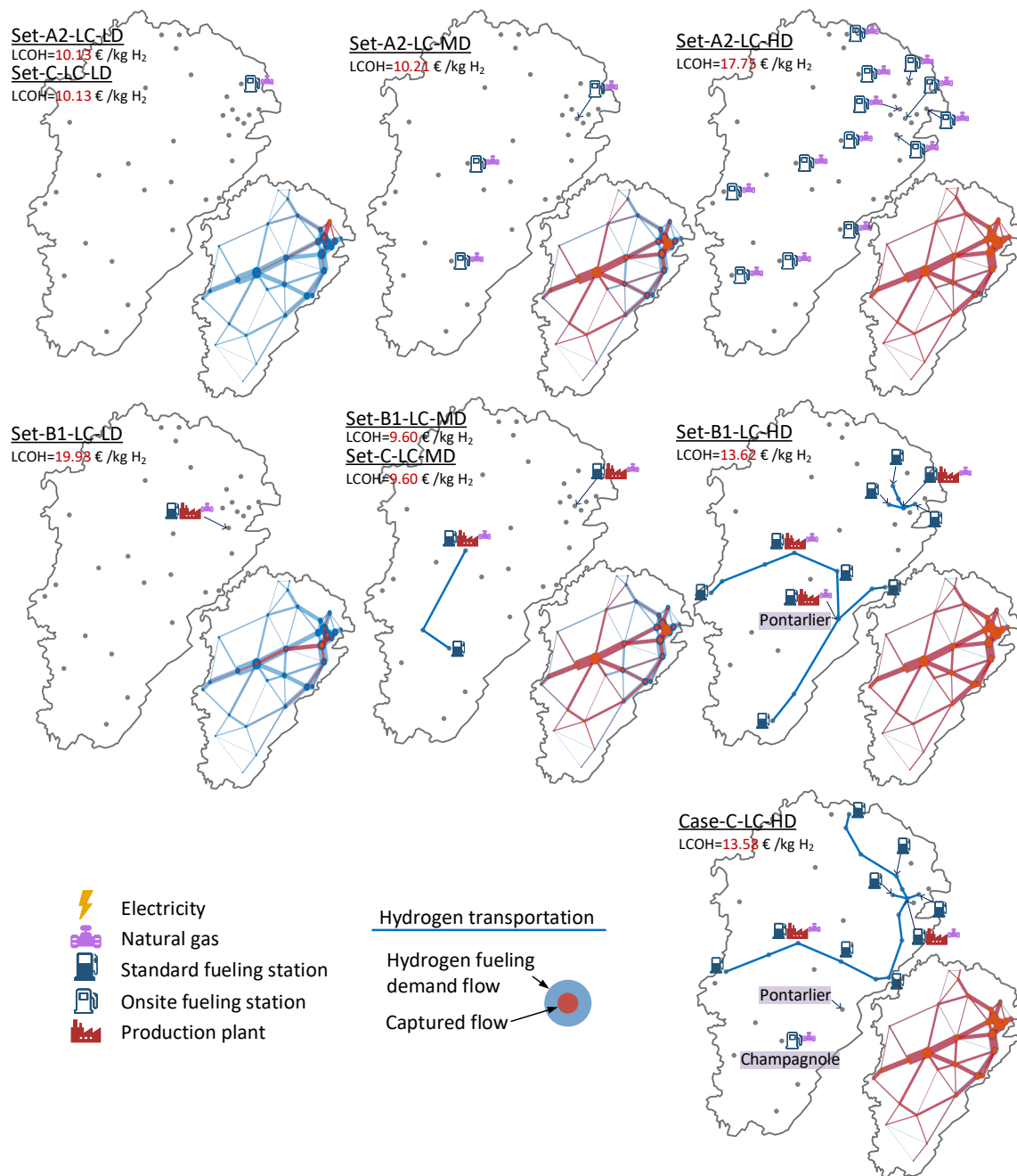


Figure 9: Configurations of Set A2, B1 and C with low carbon price

727 could help the model to find a better configuration (Fig. 10). Based on case input, biomass is
 728 supplied only at Luxeuil-les-Bains and Valdahon. In Set-B3-LC-HD, as feedstock transportation
 729 is not allowed, the model has to put two BG plants at the two cities. Notice that four fueling
 730 stations are located in the urban agglomerations in the northeast. It is reasonable to assume that

731 lower LCOH could be reached if the BG plant at Luxeuil-les-Bains is relocated within or near the
 732 urban agglomerations, and hydrogen transportation is replaced by feedstock transportation. This
 733 assumption is verified with the instance Set-D-LC-HD. For the two instances, one obtains the same
 734 number and locations of fueling stations. The change in LCOH results only from the involvement
 735 of feedstock transportation.

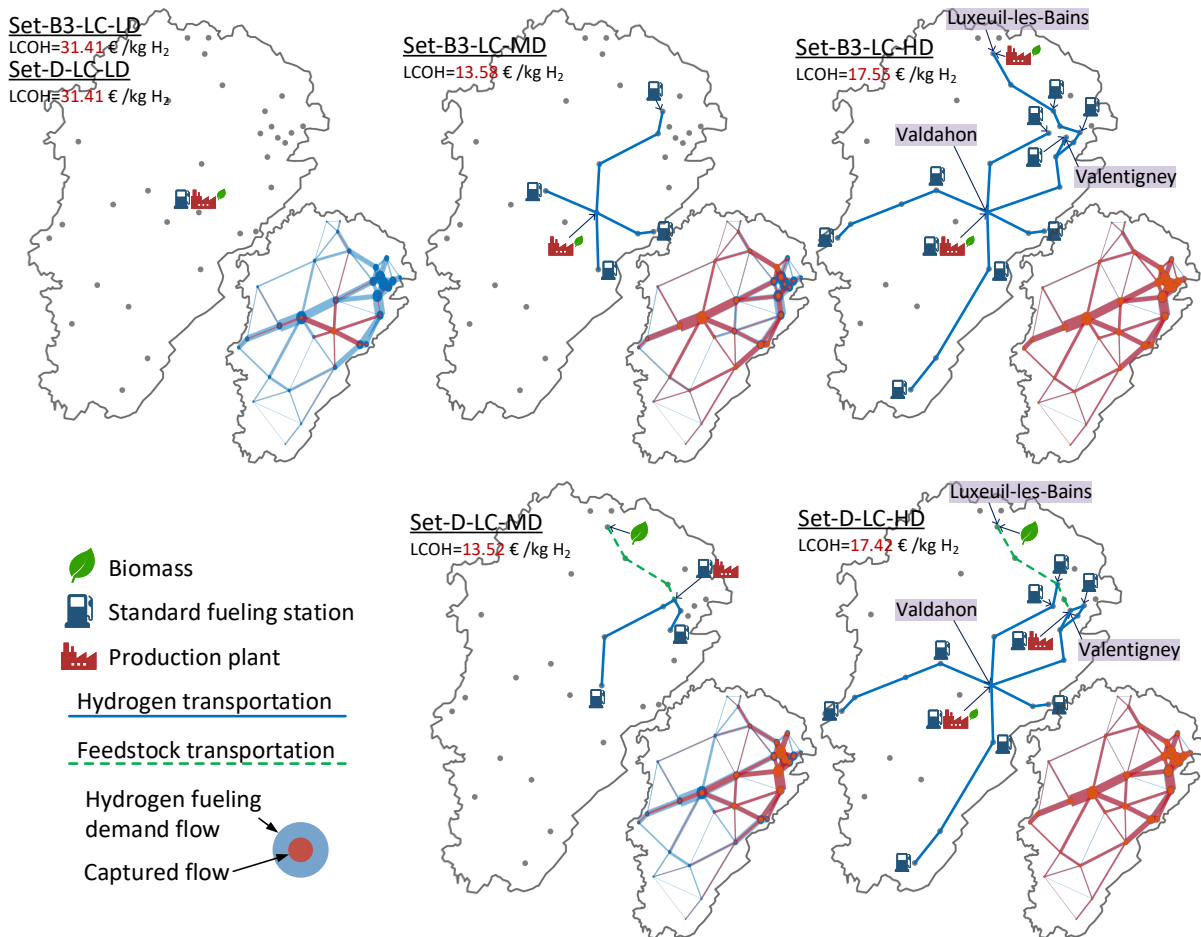


Figure 10: Configurations of Set B3 and D with low carbon price

736 *6.5. Role of CCS system*

737 Feedstock type and value of carbon price are two key factors that influence the choice of a CCS
 738 system. The optimal solution provided by the model does not include a CCS system in both low
 739 and high carbon price scenarios when natural gas is selected as feedstock (Set B1 vs. Set E1). It
 740 can be explained by the fact that the reduction in emission cost is not comparable to the expenses
 741 of a CCS system. The characteristic of biomass is that its upstream emission factor is negative. If a
 742 BG plant adopts a CCS system, 90% of its on-site emission will be captured so that the plant's CO₂

743 emissions are negative for every 1 kg of hydrogen produced using biomass. Hydrogen production
 744 plant emissions account for most of the total emissions of HSCN. Therefore, the entire system's
 745 emissions would likely be negative, and the system gains revenue because of negative emissions.

746 Fig. 6 - (e) provides obtained values of LCOH for Set B3 and E2. The model employs a
 747 CCS system only at medium and high demand in the high carbon price scenario. Analyzing the
 748 composition of LCOH shows that, although the adoption of a CCS system greatly increases the
 749 capital and operating costs, the negative emission reduces the overall cost, which makes the LCOH
 750 smaller. The obtained configurations are illustrated in Fig. 11. Notice that at high demand,
 751 only emission of the BG plant at Valdahon is captured, whereas emission of another BG plant
 752 at Luxeuil-les-Bains is not captured. This could be explained as Luxeuil-les-Bains is too far from
 753 Morteau, where the CO₂ storage site is located. If the model resulted in capturing emissions of the
 754 BG plant at Luxeuil-les-Bains, a 127 km CO₂ pipeline should be installed, adding a huge capital
 755 cost of 10.16 million euros. It can be concluded that a CCS system is attractive only at a high level
 756 of hydrogen demand and in high carbon price scenarios. Only when using biomass as feedstock,
 757 can benefits resulting from the reduction of emissions outweigh the huge expenses of adopting a
 758 CCS system.

759 Apart from carbon price, another leading strategy to promote CO₂ emission reductions is the
 760 maximum CO₂ emission constraint. The French government has set the carbon budget (CO₂
 761 emission constraint) for the transport sector in 2029–2033 as 94 million metric tons per year (CO₂
 762 equivalent) (Ministère de la Transition écologique et solidaire, 2018). Generally, the emission
 763 contributions of light duty vehicles (LDVs) account for 60% in the transport sector, which is 56.4
 764 million metric tons per year in France. Multiplying this value with the proportion of province
 765 (Franche-Comté) population to France population (1.8%), one obtains the maximum emission of
 766 LDVs in Franche-Comté as 1 million metric tons per year. Assuming that the share of FCEVs
 767 in LDVs in Franche-Comté in 2030 is 2%, the maximum allowable emission limit for the HSCN
 768 designed in this study is 54,970 kg CO₂/d. A new parameter er^{max} is used to represent this upper
 769 bound and a new constraint is introduced:

$$ER \leq er^{max} \quad (81)$$

770 where ER is the total emission rate (kg CO₂/d) of the entire network.

771 The new constraint is imposed to Set E1 and E2 to observe the changes in network configuration
 772 under the simultaneous influences of carbon price and maximum emission constraint. It is found
 773 that configuration changes only occur in Set-E1-LC-HD and Set-E1-HC-HD. These two instances
 774 have the same ER (before the new constraint is applied) of 73,096 kg CO₂/d, which is larger than
 775 the maximum allowable emission limit. Fig. 12 illustrates these configuration changes. Notice
 776 that before the new constraint is introduced, Set-E1-LC-HD and Set-E1-HC-HD have the same
 777 configurations. They both have ten standard fueling stations and three production plants, located

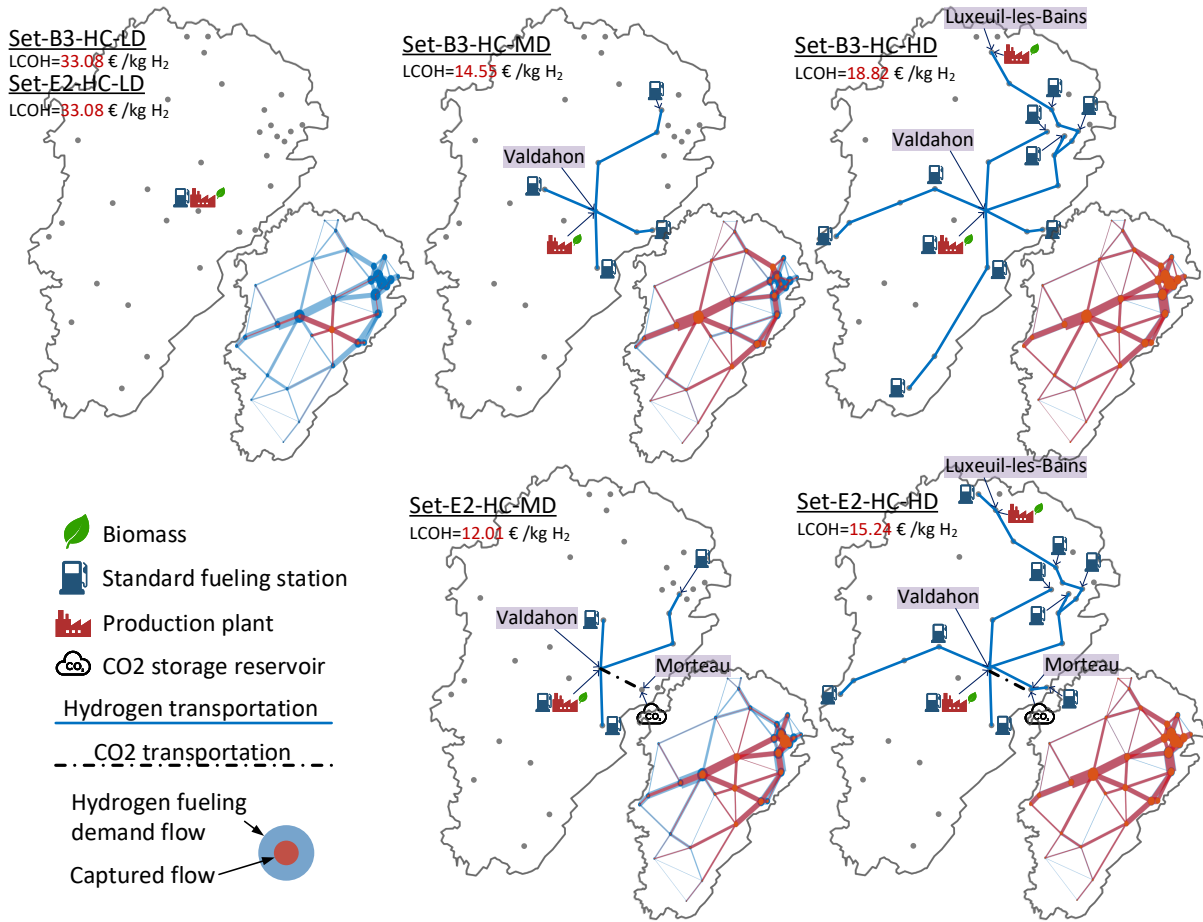


Figure 11: Configurations of Set B3 and E2 with high carbon price

778 in Besançon (production rate: 1,704 kg H₂/d), Valentigney (2,991 kg H₂/d), and Pontarlier (1,000
 779 kg H₂/d). After the maximum emission constraint is applied, both instances adopt a CCS system.
 780 In addition, the production capacity has been re-deployed, and the hydrogen transportation has
 781 been re-organized. In the low carbon price scenario, the model chooses to capture the emission
 782 of the plant at Pontarlier. To capture sufficient emissions to reduce the total emissions below
 783 er^{max} , Besançon's plant has been closed, and its production capacity is transferred to the plant
 784 at Pontarlier. The reduction in the number of plants has made the system more dependent on
 785 hydrogen transportation, and the number of hydrogen transportation vehicles has increased from
 786 three to five. In the high carbon price scenario, the model chooses to capture even more emissions
 787 through centralized production. A large plant is located at Pont-de-Roide-Vermondans, where
 788 49% of total emissions of the entire supply network are captured and processed. This value is only
 789 28% in the low carbon price scenario. Although this results in long CO₂ pipeline distance (52
 790 km compared to 29 km in the low carbon price scenario), the cost savings from further reduction

791 of emissions outweighs the increased capital cost. Based on this observation, it can be concluded
 792 that the maximum emission constraint forces instances where ER (before the new constraint is
 793 applied) is larger than er^{max} to adopt a CCS system. In the low carbon price scenario, the model
 794 only captures a small portion of emissions to satisfy the new constraint. In the high carbon price
 795 scenario, the model chooses to capture more emissions to reduce the carbon cost.

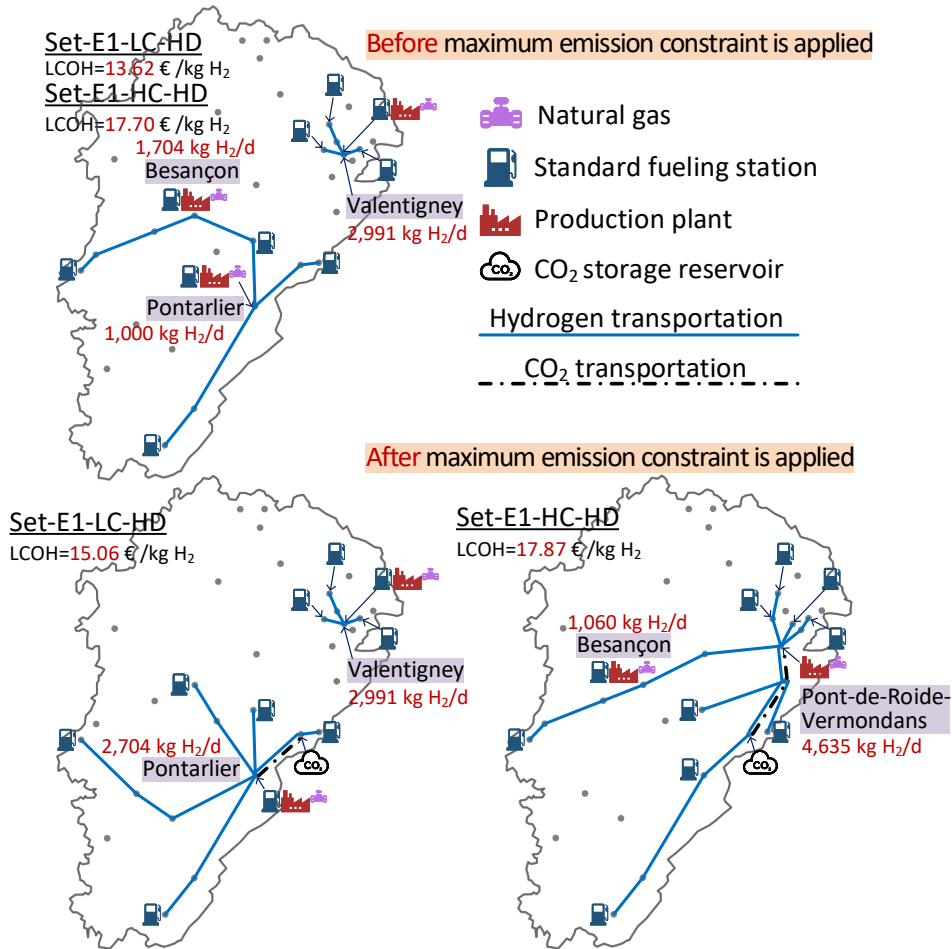


Figure 12: Configuration changes of Set-E1-LC(HC)-HD after the introduction of maximum emission constraint

796 *6.6. Role of fixed-location demand*

797 Fig. 13 shows the supply chain configurations provided by running the model with associated
 798 instances. To satisfy the fixed-location demand, instances in Set F have to build more facilities than
 799 those in Set B1. Take the medium-demand scenario as an example, Set B1 installs three fueling
 800 stations at three major cities - Valentigney, Besançon, and Champagnole, and two production
 801 plants at Valentigney and Besançon. Remember that fixed-location demands can be supplied only

802 by production plants. Set F builds a plant at Pontarlier, which facilitates the supply for fixed-
 803 location demand of Type A at Saint-Claude and fixed-location demand of Type B at Pontarlier.
 804 For Set F, a standard fueling station is installed at Pontarlier because there exists fixed-location
 805 demand of Type B. However, the fueling demand flow captured by this station is less than that
 806 of major cities. Therefore, the model has to build an additional station to capture 50% of fueling
 807 demand flow. Fig. 6 - (f) compares the values of LCOH for those two sets. Although the total
 808 daily cost for Set F is higher than Set B1, it obtains lower LCOH because a higher amount of
 809 hydrogen is sold.

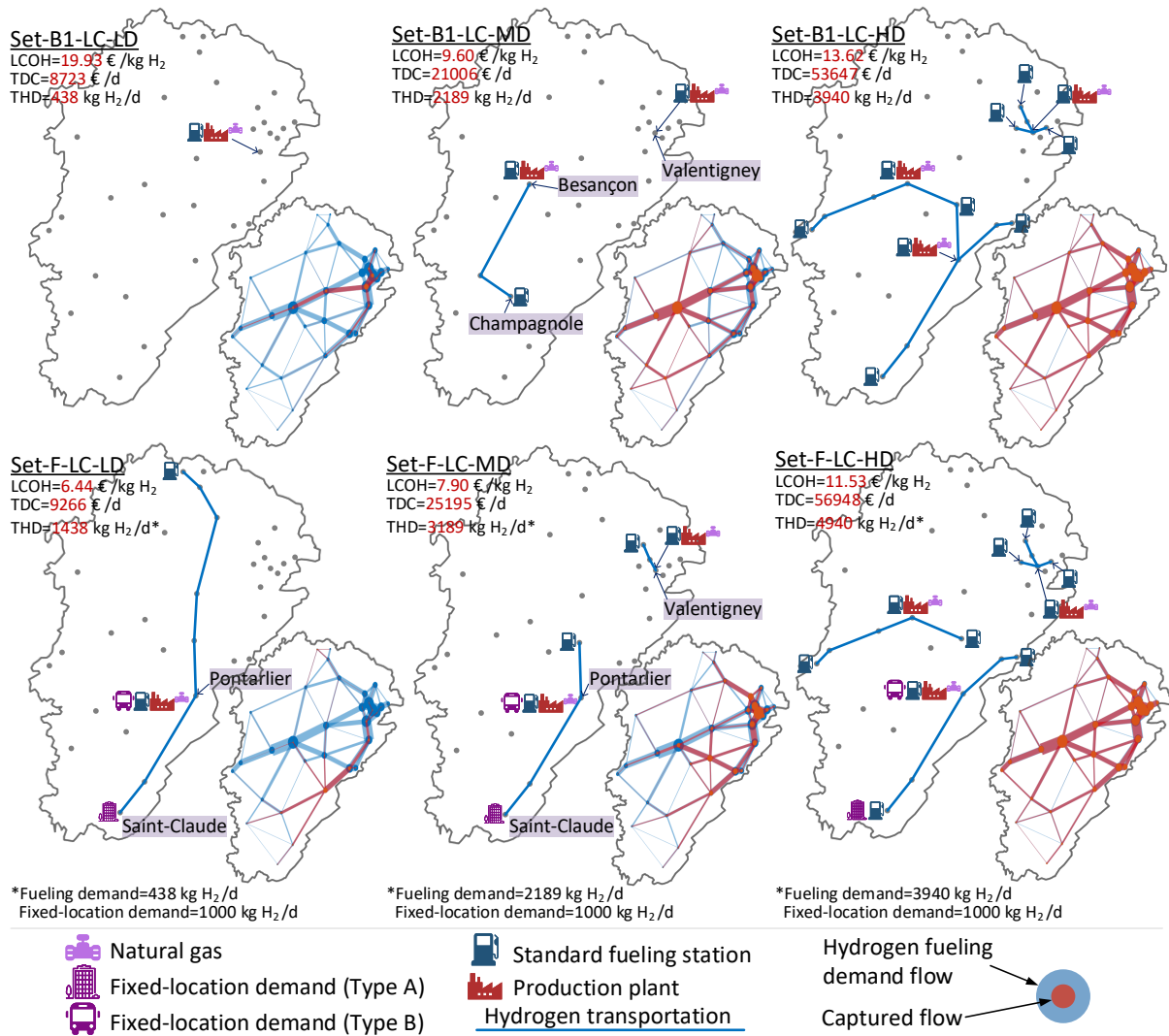


Figure 13: Configuration for Set B1 and F with low carbon price

810 6.7. The construction plan for Franche-Comté

811 Group G provides the complete instances in which all types of components are available to
 812 design the Franche-Comté hydrogen supply chain. Fig. 14 illustrates the configurations obtained
 813 in low and high carbon price scenarios. Notice that no on-site stations are installed in the presented
 814 configurations. This can be explained by the existence of fixed-location demand, which relies on
 815 hydrogen delivered by production plants. In the low carbon price scenario, the model selects SMR
 816 because production technology such as SMR plants are less expensive in capital cost, and the
 817 HSCN is built on gaseous hydrogen. The observed differences between the configurations of the
 818 two scenarios are that a CCS system has been adopted at medium and high demand and that BG
 819 plants are chosen instead of SMR plants. It is noteworthy that, CO₂ emissions of the two BG
 820 plants at high demand are all captured by the CCS system. The model chooses to install the two
 821 BG plants near the CO₂ storage site and accepts the long distances of feedstock transportation.

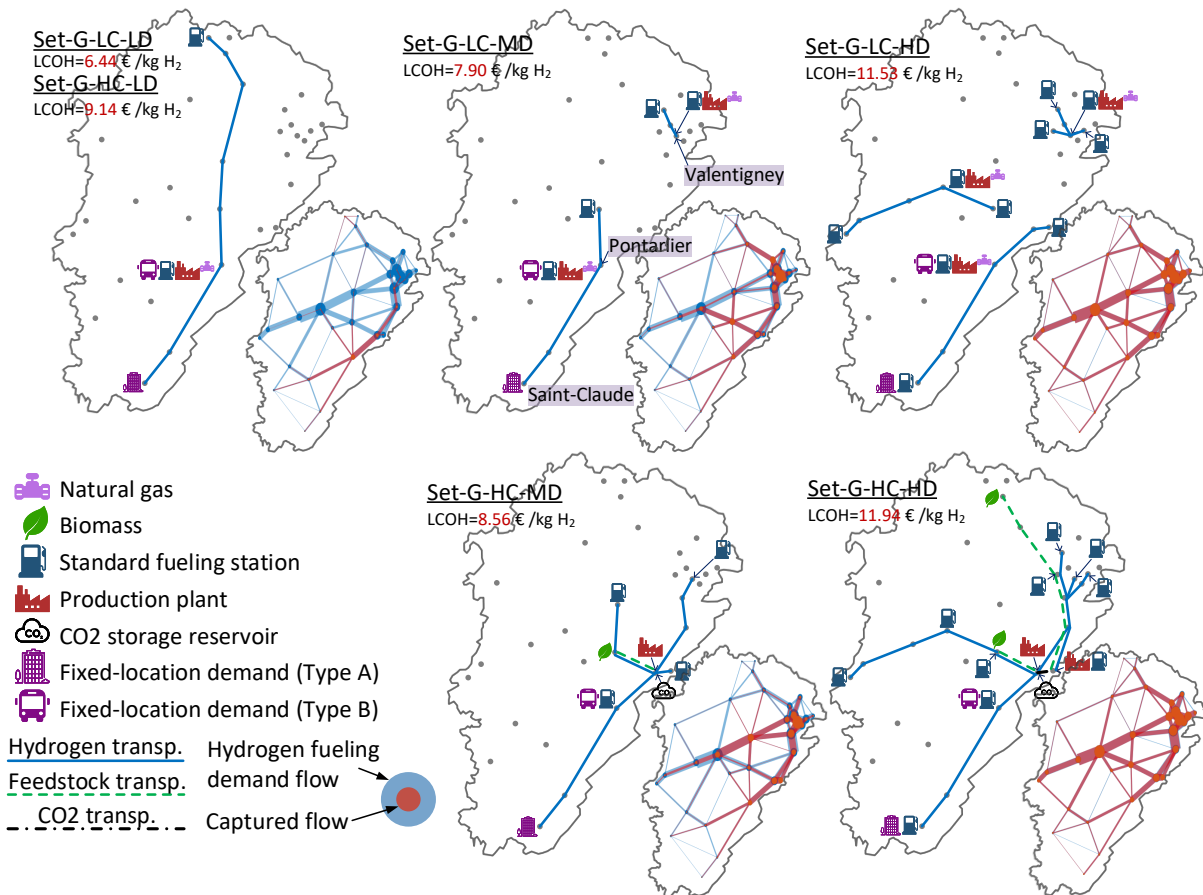


Figure 14: Configurations of Set G

822 **7. Conclusion**

823 The hydrogen supply chain network in the transportation sector is a complex system. It
824 includes various components from feedstock supply sites to hydrogen fueling stations. Because
825 of the inherent characteristics of a supply chain, each part of HSCN is interconnected rather than
826 isolated. The selection of feedstock, production and fueling technology, locations of hydrogen
827 facilities, and other major decisions make up a vast “pool” of pathways, each of which has a
828 different value of LCOH and network configuration. For decision-makers, it is challenging to make
829 intelligent designs without support from optimization models.

830 In this paper, a mathematical optimization model was developed, which integrates the hydrogen
831 supply chain network design and hydrogen fueling station planning. Through the case study, it
832 has been shown that first the model can provide an optimal supply configuration for a given
833 set of available infrastructures. Second, thanks to the many comparisons made, the interest of the
834 integrated model is highlighted, compared with others that consider only a subset of the components
835 from feedstock supply sites to hydrogen fueling stations. Moreover, the approach conducted to
836 validate the model consisted of executing it for each supply chain scenario considered. Therefore,
837 it has also highlighted the potentially beneficial optimization-simulation coupling, which would
838 consist of integrating this optimization model into a decision support system designed to simulate
839 the various possible deployment scenarios.

840 At this stage, the computational results of the model are promising. However, there are major
841 tasks that still need further investigation to improve it. The following tasks are summarized below:

- 842 • Consider the evolution of the HSCN over time, rather than a snapshot of the network at one
843 point in time. In real-world conditions, the formation of the hydrogen energy market and
844 the construction of the hydrogen energy supply network usually span decades. The hydrogen
845 fueling demand increases gradually. Correspondingly, the construction plan of the HSCN
846 should be designed in stages.
- 847 • Consider the interactions between the hydrogen supply (hydrogen facilities) and demand
848 (FCEV potential buyers). In the present study, the hydrogen fueling demand flow is pre-
849 defined, and it will not be affected by the hydrogen supply system. The influence of the
850 hydrogen supply on demand has been ignored. The model will be improved by converting the
851 hydrogen demand from model input to a decision variable to endogenously forecast hydrogen
852 demand while optimizing the hydrogen supply network.

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1098 Appendices

1099 A. Nomenclature

1100

1101 Parameters

α	annual network operating period, d/y
β	payback period of capital investment, y
γ_{sij}^e	standard fueling station emission factor, kg CO ₂ /kg H ₂
γ_{oj}^e	on-site fueling station emission factor, kg CO ₂ /kg H ₂
γ_h^e	emission factor of hydrogen transportation mode h , kg CO ₂ /L fuel
γ_{pik}^c	production emission capture efficiency
γ_{pik}^{eo}	production on-site emission factor, kg CO ₂ /kg H ₂
γ_{pik}^{eu}	production upstream emission factor, kg CO ₂ /kg H ₂
$\delta_{(e,o)}$	conversion rates of feedstock to hydrogen (for on-site fueling stations), unit feedstock/kg H ₂
$\delta_{(e,p)}$	conversion rates of feedstock to hydrogen (for hydrogen production plants), unit feedstock/kg H ₂
ϵ	a small positive number
$ccap_n^{max}$	upper limit of CO ₂ processing capacity, kg CO ₂ /d
$ccap_n^{min}$	lower limit of CO ₂ processing capacity, kg CO ₂ /d

ccc	capital cost of a CO ₂ storage site, €
coc	operating cost of CO ₂ processing, €/kg CO ₂
cp	carbon price, €/kg CO ₂
$cpec$	capital cost of CO ₂ pipeline, €/km
$dem^{h,exp}$	percentage of hydrogen demand flow that expected to be captured, %
$dem_{ni}^{h,A}$	fixed-location hydrogen demand (Type A) of each node, kg H ₂ /d
$dem_{ni}^{h,B}$	fixed-location hydrogen demand (Type B) of each node, kg H ₂ /d
dw_h	driver wage of hydrogen transportation mode h , €/h
dw_f	driver wage of feedstock transportation mode f , €/h
$ecap_{ne}^{max}$	upper limit of feedstock supply capacity at each node, unit feedstock/d
$ecap_{ne}^{min}$	lower limit of feedstock supply capacity at each node, unit feedstock/d
eoc_e	operating cost of a feedstock site, €/d
euc_e	feedstock unit cost, €/unit feedstock
$fcap_{sij}^{max}$	upper limit of standard fueling capacity, kg H ₂ /d
$fcap_{sij}^{min}$	lower limit of standard fueling capacity, kg H ₂ /d
$fcap_{oj}^{max}$	upper limit of on-site fueling capacity, kg H ₂ /d
$fcap_{oj}^{min}$	lower limit of on-site fueling capacity, kg H ₂ /d
fcc_{sij}	capital cost of a standard fueling station, €
fcc_{oj}	capital cost of an on-site fueling station, €
fe_h	fuel economy of hydrogen transportation mode h , km/L fuel
fe_f	fuel economy of feedstock transportation mode f , km/L fuel
f_n^{node}	hydrogen fueling demand flow of each node, kg H ₂ /d
foc_{sij}	operating cost of a standard fueling station, €/kg H ₂
foc_{oj}	operating cost of an on-site fueling station, €/kg H ₂
fp_h	fuel price of hydrogen transportation mode h , €/L fuel
fp_f	fuel price of feedstock transportation mode f , €/L fuel
f_q^{pair}	hydrogen fueling demand flow of each OD (Origin–Destination) pair, kg H ₂ /d
ge_h	general expense of hydrogen transportation mode h , €/d
ge_f	general expense of feedstock transportation mode f , €/d
$id_n^{h,A}$	equals 1 if there exists fixed-location hydrogen demand (Type A) at this node (0 otherwise)
$id_n^{h,B}$	equals 1 if there exists fixed-location hydrogen demand (Type B) at this node (0 otherwise)
l_{nm}	the shortest distance between two different nodes, km
lut_h	load/unload time of hydrogen transportation mode h , h
lut_f	load/unload time of feedstock transportation mode f , h
me_h	maintenance expense of hydrogen transportation mode h , €/km
me_f	maintenance expense of feedstock transportation mode f , €/km

$pcap_{pik}^{max}$	upper limit of production capacity, kg H ₂ /d
$pcap_{pik}^{min}$	lower limit of production capacity, kg H ₂ /d
pcc_{pik}	capital cost of a production plant, €
poc_{pik}	operating cost of a production plant, €/kg H ₂
sp_h	speed of hydrogen transportation mode h , km/h
sp_f	speed of feedstock transportation mode f , km/h
$tcap_h$	capacity of hydrogen transportation mode h , kg H ₂
$tcap_f$	capacity of feedstock transportation mode f , unit feedstock
$tcap_h^{max}$	upper limit of hydrogen transportation capacity between two nodes, kg H ₂ /d
$tcap_f^{max}$	upper limit of feedstock transportation capacity between two nodes, unit feedstock/d
$tcap_h^{min}$	lower limit of hydrogen transportation capacity between two nodes, kg H ₂ /d
$tcap_f^{min}$	lower limit of feedstock transportation capacity between two nodes, unit feedstock/d
$tcap^{max}$	upper limit of CO ₂ transportation capacity, kg CO ₂ /d
$tcap^{min}$	lower limit of CO ₂ transportation capacity, kg CO ₂ /d
tcr_h	vehicle rental cost of hydrogen transportation mode h (for each vehicle), €/d
tcr_f	vehicle rental cost of feedstock transportation mode f (for each vehicle), €/d
tma_h	availability of hydrogen transportation mode h , h/d
tma_f	availability of feedstock transportation mode f , h/d

1102 *Continuous variables*

CC	total daily capital cost, €/d
CR	total processing rate of CO ₂ , kg CO ₂ /d
CR_n	CO ₂ processing rate of a CO ₂ storage site, kg CO ₂ /d
$DEM^{h,cap}$	percentage of hydrogen demand flow that could be captured, %
EC	daily feedstock purchasing cost, €/d
EMC	daily emission cost, €/d
ER	total emission rate, kg CO ₂ /d
ESR_e	total feedstock supply rate of feedstock sites, unit feedstock/d (feedstock type e)
FCC	daily facility capital cost, €/d
FFC	daily feedstock transportation fuel cost, €/d
FGC	daily feedstock transportation general cost, €/d
FLC	daily feedstock transportation labor cost, €/d
FMC	daily feedstock transportation maintenance cost, €/d
FOC	daily facility operating cost, €/d
FR_{noj}	fueling rate of an on-site fueling station, kg H ₂ /d

	(fueling technology o , size j)
FR_{nsij}	fueling rate of a standard fueling station, kg H ₂ /d (fueling technology s , hydrogen form i , size j)
FR_{oj}	total fueling rate of on-site fueling stations, kg H ₂ /d (fueling technology o , size j)
FR_{sij}	total fueling rate of standard fueling stations, kg H ₂ /d (fueling technology s , hydrogen form i , size j)
FRC	daily feedstock transportation vehicle rental cost, €/d
$FTOC$	daily feedstock transportation operating cost, €/d
HFC	daily hydrogen transportation fuel cost, €/d
HGC	daily hydrogen transportation general cost, €/d
HLC	daily hydrogen transportation labor cost, €/d
HMC	daily hydrogen transportation maintenance cost, €/d
HRC	daily hydrogen transportation vehicle rental cost, €/d
$HTOC$	daily hydrogen transportation operating cost, €/d
$LCOH$	least cost of hydrogen, €/kg H ₂
OC	total daily operating cost, €/d
$OESR_{ne}$	feedstock supply rate for the on-site fueling station at node n , unit feedstock/d (feedstock type e)
$OFER$	total emission rate of on-site fueling stations, kg CO ₂ /d
PER	total production emission rate, kg CO ₂ /d
PER^c	total emission rate of production plants where emissions are processed, kg CO ₂ /d
PER_n^c	emission rate of a production plant where emissions are processed, kg CO ₂ /d
$PESR_{ne}$	feedstock supply rate for production plants at node n or built at other nodes, unit feedstock/d, (feedstock type e)
PR_{npik}^c	production rate of a production plant where emissions are processed, kg H ₂ /d
PR_{npik}	production rate of a production plant, kg H ₂ /d (production technology p , hydrogen form i , size k)
PR_{pik}	total production rate of production plants, kg H ₂ /d (production technology p , hydrogen form i , size k)
Q_{fnm}	feedstock transportation flux from node n to m , unit feedstock/d (transportation mode f)
Q_{hnm}	hydrogen transportation flux from node n to m , kg H ₂ /d (transportation mode h)
Q_{nm}	CO ₂ transportation flux from node n to m , kg CO ₂ /d
$SFER$	total emission rate of standard fueling stations, kg CO ₂ /d
TCC	daily CO ₂ transportation capital cost, €/d
TDC	total daily cost, €/d
TER	total emission rate of hydrogen transportation, kg CO ₂ /d

THD the amount of hydrogen delivered per day, kg H₂/d

1103 *Integer variables*

NE_e number of feedstock supply sites (for hydrogen production plants)
(feedstock type e)

NF_{sij} number of standard fueling stations
(fueling technology s , hydrogen form i , size j)

NF_{oj} number of on-site fueling stations
(fueling technology o , size j)

NP_{pik} number of production plants
(production technology p , hydrogen form i , size k)

NR number of CO₂ storage reservoirs

NV_h number of hydrogen transportation vehicles

NV_f number of feedstock transportation vehicles

1104 *Binary variables*

IC_q 1 if hydrogen fueling demand flow pair q is captured

IE_n 1 if the node is chosen as a feedstock supplier of production plants

IE_{ne} 1 if the node is chosen as a feedstock supplier of production plants (feedstock type e)

IF_n 1 if there is a fueling station at this node

IF_{no} 1 if there is an on-site fueling station at this node
(fueling technology o)

IF_{nsij} 1 if there is a standard fueling station at this node
(fueling technology s , hydrogen form i , size j)

IF_{noj} 1 if there is an on-site fueling station at this node
(fueling technology o , size j)

IM_n 1 if the emission of production plant at this node is processed

IP_n 1 if there is a production plant at this node

IP_{npik} 1 if there is a production plant at this node
(production technology p , hydrogen form i , size k)

IR_n 1 if there is a CO₂ storage site at this node

OIF_n 1 if there is an on-site fueling station at this node

SIF_n 1 if there is a standard fueling station at this node

X_{fnm} 1 if feedstock is to be transported from node n to m
in transportation mode f

X_{hnm} 1 if hydrogen is to be transported from node n to m
in transportation mode h

X_{nm} 1 if CO₂ is to be transported from node n to m

Table B.1: Population and demographic metrics values of 31 cities

City	Population (person)	Vehicle (%)	Income (€/year)	Education (%)	Commute (%)
Baume-les-Dames	5,255	55.45	19,395	12.90	73.87
Bavans	3,701	68.25	20,224	15.70	81.31
Beaucourt	5,047	63.96	19,884	14.70	82.29
Belfort	63,683	37.22	17,604	15.03	63.88
Besançon	116,690	33.11	18,583	15.80	61.65
Champagnole	7,908	45.91	19,059	14.10	72.08
Delle	5,773	54.42	19,483	15.20	76.37
Dole	23,312	46.34	18,813	15.40	71.09
Fougerolles	5,504	36.90	15,679	15.80	67.62
Gray	3,721	71.08	19,023	15.00	83.78
Hauts de Bienne	5,457	48.44	19,561	12.80	72.18
Héricourt	9,967	60.50	18,630	14.00	79.25
Hérimoncourt	3,635	60.87	19,600	15.50	84.24
Lons-le-Saunier	17,311	34.21	18,185	17.90	63.87
Lure	8,324	46.88	17,174	14.80	68.98
Luxeuil-les-Bains	6,917	46.83	17,003	14.80	73.67
Maïche	4,233	59.06	23,853	15.00	85.30
Montbéliard	40,733	46.28	16,734	13.37	73.98
Morteau	6,827	51.62	27,219	18.50	77.14
Ornans	4,329	57.94	20,775	15.50	71.81
Poligny	4,146	51.53	18,975	17.00	68.40
Pontarlier	17,413	45.44	21,995	16.70	71.36
Pont-de-Roide-Vermondans	4,230	62.47	19,497	14.70	75.54
Saint-Claude	10,096	45.11	18,032	12.40	68.70
Saint-Loup-sur-Semouse	3,263	52.00	15,493	12.00	68.40
Saint-Vit	4,803	60.38	20,718	16.40	83.40
Tavaux	3,957	63.91	21,373	15.80	82.25
Valdahon	5,344	44.76	20,614	20.20	63.22
Valentigney	34,877	57.10	17,875	13.86	79.72
Vesoul	15,212	34.31	17,159	14.50	66.37
Villers-le-Lac	4,750	65.32	30,370	16.60	88.26

Source: Population, Income - (L'Institut national de la statistique et des études économiques, 2018a); Vehicle, Commute - (L'Institut national de la statistique et des études économiques, 2015a); Education - (L'Institut national de la statistique et des études économiques, 2018b).

Note: Combinations of adjacent cities -

Belfort = Belfort+Bavilliers+Offemont+Valdoie;

Montbéliard = Montbéliard+Bethoncourt+Grand Charmont+Sochaux;

Valentigney = Valentigney+Audincourt+Seloncourt+Mandeure;

The values of combined cities are obtained by weighted average method (on population).

Table B.2: Production technology - steam methane reforming (SMR)

	Hydrogen form:			Gaseous			Liquid			Source
	Facility size:	Small	Medium	Large	Small	Medium	Large			
Capital cost	million €	1.05	1.70	2.28	10.62	16.70	21.78	(1)		
Operating cost	€/kg H ₂	0.34	0.31	0.30	2.65	2.15	1.93	(2)		
Maximum capacity	1,000 kg/d	2.00	3.50	5.00	2.00	3.50	5.00			
Minimum capacity	1,000 kg/d	1.00	2.50	4.00	1.00	2.50	4.00			
Upstream emission factor	kg CO ₂ /kg H ₂	2.40	2.40	2.40	3.07	3.00	2.97	(3)		
On-site emission factor	kg CO ₂ /kg H ₂	8.66	8.66	8.66	8.66	8.66	8.66	(4)		
Emission capture efficiency		0.90	0.90	0.90	0.90	0.90	0.90	(5)		

Source: (1), (2), (4) - (Department of Energy, 2010, 2018c); (3) - (Department of Energy, 2010, 2018c; Électricité de France, 2018); (5) - (Department of Energy, 2018b).

Note: The costs of liquid production (capital and operating) are obtained by adding the cost of liquefier to gaseous production.

Table B.3: Production technology - Electrolysis

	Hydrogen form:			Gaseous			Liquid			Source
	Facility size:	Small	Medium	Large	Small	Medium	Large			
Capital cost	million €	1.74	2.62	3.92	11.32	17.62	23.43	(1)		
Operating cost	€/kg H ₂	0.17	0.14	0.11	2.48	1.98	1.74	(2)		
Maximum capacity	1,000 kg/d	2.00	3.50	5.00	2.00	3.50	5.00			
Minimum capacity	1,000 kg/d	1.00	2.50	4.00	1.00	2.50	4.00			
Upstream emission factor	kg CO ₂ /kg H ₂	1.96	1.57	1.26	2.63	2.17	1.83	(3)		
On-site emission factor	kg CO ₂ /kg H ₂	-	-	-	-	-	-			
Emission capture efficiency		0.90	0.90	0.90	0.90	0.90	0.90	(4)		

Source: (1), (2) - (Department of Energy, 2010, 2018d); (3) - (Department of Energy, 2010, 2018d; Électricité de France, 2018); (4) - (Department of Energy, 2018b).

Note: The costs of liquid production (capital and operating) are obtained by adding the cost of liquefier to gaseous production; Because lack of information, the upstream emission factor of “Medium” and “Large” (gaseous production) are obtained by multiplying the value of “Small” with 0.8 and 0.64, respectively.

Table B.4: Production technology - biomass gasification (BG)

	Hydrogen form:						Source
	Gaseous			Liquid			
	Small	Medium	Large	Small	Medium	Large	
Capital cost	million €	4.09	7.03	9.64	13.67	22.03	29.15 (1)
Operating cost	€/kg H ₂	4.01	2.48	1.90	6.32	4.33	3.52 (2)
Maximum capacity	1,000 kg/d	2.00	3.50	5.00	2.00	3.50	5.00
Minimum capacity	1,000 kg/d	1.00	2.50	4.00	1.00	2.50	4.00
Upstream emission factor	kg CO ₂ /kg H ₂	-22.26	-22.26	-22.26	-21.59	-21.66	-21.69 (3)
On-site emission factor	kg CO ₂ /kg H ₂	24.00	24.00	24.00	24.00	24.00	24.00 (4)
Emission capture efficiency		0.90	0.90	0.90	0.90	0.90	0.90 (5)

Source: (1), (2), (4) - (Department of Energy, 2010, 2018b); (3) - (Department of Energy, 2010, 2018b; Électricité de France, 2018); (5) - (Department of Energy, 2018b).

Note: The costs of a liquid production plant (capital and operating) are obtained by adding the cost of a liquefier to a gaseous production plant.

The upstream emission factors are negative because the plants that are the source of biomass capture a certain amount of CO₂ through photosynthesis while they are growing.

Table B.5: Standard fueling technology

	Hydrogen form:						Source
	Gaseous			Liquid			
	Small	Medium	Large	Small	Medium	Large	
Capital cost	million €	1.08	1.87	2.10	1.16	1.52	1.57 3.14 (1)
Operating cost	€/kg H ₂	3.28	2.20	1.28	5.39	2.66	1.45 1.45 (2)
Maximum capacity	1,000 kg/d	0.15	0.30	0.60	0.15	0.30	0.60 1.20 (3)
Minimum capacity	1,000 kg/d	0.05	0.15	0.30	0.05	0.15	0.30 0.60 (4)
Emissions factor	kg CO ₂ /kg H ₂	2.34	2.07	1.59	0.42	0.41	0.41 0.41 (5)

Source: (1), (2), (5) - (Department of Energy, 2010); (3), (4) - (L'Association Française pour l'Hydrogène et les Piles à Combustible, 2018).

Table B.6: On-site fueling technologies

	On-site fueling techn.:			On-site-SMR			On-site-electrolysis			Source
	Facility size:	Small	Medium	Large	Extra-large	Small	Medium	Large	Extra-large	
Capital cost	million €	1.26	2.18	2.59	5.19	1.32	2.27	2.75	5.50	(1)
Operating cost	€/kg H ₂	4.57	3.31	2.21	2.21	4.15	2.97	1.79	1.79	(2)
Maximum capacity	1,000 kg/d	0.15	0.30	0.60	1.20	0.15	0.30	0.60	1.20	(3)
Minimum capacity	1,000 kg/d	0.05	0.15	0.30	0.60	0.05	0.15	0.30	0.60	(4)
Emissions factor	kg CO ₂ /kg H ₂	19.49	16.25	13.54	13.54	5.34	4.45	3.71	3.71	(5)

Source: (1), (2) - (Department of Energy, 2018c,d; Melaina & Penev, 2013); (3), (4) - (L'Association Française pour l'Hydrogène et les Piles à Combustible, 2018); (5) - (Department of Energy, 2018c,d; Électricité de France, 2018).

Note: The costs of an on-site station (capital and operating) are obtained by adding the cost of on-site production to a gaseous standard station.

Due to lack of information, the emission factor of "Medium" and "Small" are obtained by multiplying the value of "Large" with 1.2 and 1.44, respectively.

Table B.7: Hydrogen and feedstock transportation: cost and emission data

		Hydrogen		Biomass	Source
		Tube trailer	Tanker truck	Truck	
Driver wage	€/h	20.47	20.47	20.47	(1)
Fuel economy	km/L	2.55	2.55	2.55	(2)
Fuel price	€/L	1.46	1.46	1.46	(3)
General expenses	€/d	7.32	7.32	7.32	(4)
Load/unload time	h	2.00	2.00	2.00	(5)
Maintenance expenses	€/km	0.09	0.09	0.09	(6)
Average speed	km/h	55.00	55.00	55.00	(7)
Availability	h/d	18.00	18.00	18.00	(8)
Emissions factor	kg CO ₂ /L	2.68	2.68	2.68	(9)
Capacity	1,000 kg	0.18	4.08	8.00	(10)
Vehicle rental cost	€/d	71.20	89.00	44.50	(11)
Maximum transport capacity	1,000 kg/d	5.00	5.00	69.40	
Minimum transport capacity	1,000 kg/d	0.05	0.05	8.00	

Source: (1), (2), (4), (5), (6), (7), (8) - (Almansoori & Shah, 2006); (3) - (GlobalPetrolPrices, 2019); (9) - (Almansoori & Betancourt-Torcat, 2016); (10) - (Almansoori & Shah, 2006; RentalYard, 2018); (11) - (RentalYard, 2018).

Note: The maximum transport capacity is based on the assumption that individual modes cannot transport more than what is produced by a large production facility.

Table B.8: Feedstock prices, conversion rates, and CCS system inputs

Parameter		Value	Source
Natural gas price	€/Nm ³	0.36	(1)
Electricity price	€/kWh	0.10	(2)
Biomass price	€/kg	0.05	(3)
Conversion rate (SMR)	Nm ³ Natural gas/kg H ₂	4.61	(4)
Conversion rate (Electrolysis)	kWh Electricity/kg H ₂	54.60	(5)
Conversion rate (BG)	kg Biomass/kg H ₂	13.88	(6)
CCS capital cost	million €	2.03	(7)
CO ₂ pipeline capital cost	million €/km	0.08	(8)
CO ₂ processing cost	€/kg	0.09	(9)
CO ₂ transport capacity (Max)	1,000 kg/d	500.00	
CO ₂ transport capacity (Min)	1,000 kg/d	-	

Source: (1) - (Statista, 2019b); (2) - (Statista, 2019a); (3), (6) - (National Renewable Energy Laboratory, 2011); (4) - (Department of Energy, 2018c); (5) - (Department of Energy, 2018d); (7), (8), (9) - (Department of Energy, 2018b)

1107 C. Supplementary material

1108 Supplementary material can be found in the submission files, with the name of *Supplementary-*
 1109 *Material.pdf*.

