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The importance of economies of scale, transport costs and demand patterns in optimising hydrogen fuelling infrastructure: An exploration with SHIPMod (Spatial hydrogen infrastructure planning model)☆

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ABSTRACT

Hydrogen is widely recognised as an important option for future road transportation, but a widespread infrastructure must be developed if the potential for hydrogen is to be achieved. This paper and related appendices which can be downloaded as Supplementary material present a mixed-integer linear programming model (called SHIPMod) that optimises a hydrogen supply chains for scenarios of hydrogen fuel demand in the UK, including the spatial arrangement of carbon capture and storage infrastructure. In addition to presenting a number of improvements on past practice in the literature, the paper focuses attention on the importance of assumptions regarding hydrogen demand. The paper draws on socio-economic data to develop a spatially detailed scenario of possible hydrogen demand. The paper then shows that assumptions about the level and spatial dispersion of hydrogen demand have a significant impact on costs and on the choice of hydrogen production technologies and distribution mechanisms.

1. Introduction

A widespread infrastructure must be developed if the potential for hydrogen as an option for future road transportation is to be achieved. In recent years, a literature has emerged examining the potential development of hydrogen infrastructure by modelling optimal hydrogen supply chains (HSCs). This paper contributes to this literature by developing a spatially-explicit multi-period mixed-integer linear programming (MILP) model, called SHIPMod (Spatial Hydrogen Infrastructure Model), and applying it to scenarios for the United Kingdom.

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This paper contributes to the literature by discussing methodological developments and policy insights. Among the former, this is the first paper presenting a spatially-explicit multi-period MILP model:

- Incorporating analysis of the drivers influencing spatial and temporal H_2 demand;
- Presenting the equations for CCS pipelines;
- Applying discounting and taking into account residual value of the infrastructure;
- Examining a diffusion scenario located within the wider optimal context of an energy system model;
- Utilising a hierarchical approach which substantially improves the computational efficiency, and hence enables greater model complexity.

In addition to modelling hydrogen penetration based on underlying socio-economic factors, the paper assesses how technological choice is affected by the trade-off between economies of scale, favouring large plants, and transport costs, favouring local and smaller plants. The paper then examines whether technological choice is influenced by the dispersion, level and penetration rate of hydrogen demand. Finally, the paper investigates the implications on the optimal configuration of the system if hydrogen is produced from biomass – essentially biomass gasification is dropped from the set of production technologies which can be selected by SHIPMod. While this analysis is hypothetical, it reflects the unsettled nature of the debate about the carbon neutrality and sustainability of bioenergy.

The paper is structured as follows. Section 2 briefly surveys the existing literature reporting the modelling of hydrogen supply chains, and highlights the ways in which the paper presents an advance on previously published work. Section 3 then provides a narrative description of the model. The detailed mathematical formulation of the model, and the data used, is available in full as supplementary online material (Appendices A–F). Section 4 sets out the modelling of hydrogen demand scenarios, examining possible patterns of demand across both time and space as a transition unfolds. Section 5 describes the scenarios examined using the model, and Section 6 reports and discusses the key results from those scenarios. Finally, Section 7 concludes the paper.

2. Literature survey

A considerable interest in optimisation methods to model the introduction of hydrogen into the passenger transport sector has been witnessed in recent years. As discussed in Agnolucci and McDowall [1], optimisation techniques have been employed across a number of spatial scales, notably at national scales by applying bottom-up energy system models, and at regional and local scales by utilising Mixed Integer Linear Programming (MILP) models with explicit spatial representation of the hydrogen network. At the regional scale, MILP is by far the most commonly adopted approach used to model spatially explicit Hydrogen Supply Chains (HSC). This brief literature survey focuses on papers presenting a full description of fully-optimised MILP models. Among these papers, one can identify three families of models used to represent HSCs: Almansoori and Shah [2], Johnson and Ogden [3], and Parker et al. [4].

Parker et al. [4] present a nonlinear model maximising profits from a waste-based HSC, where the hydrogen price is taken as input to the optimisation problem. The paper takes into account a wide array of costs including production, transportation – both local and intercity – and refuelling stations. A number of constraints ensure that the optimal solution satisfies the capacity of the components of the HSC (in terms of feedstock availability, conversion facilities, hydrogen terminals and delivery options to retail stations) while ensuring that flows across the components take into account any loss factor. Given a list of potential sites for the hydrogen infrastructure, one can then compute the total costs of the HSC.[1]

The logic of the model in Johnson and Ogden [3] is similar to Parker et al. [4], although the HSC in the former is simpler. This model minimises the production and delivery cost of meeting a certain level of demand for hydrogen. Only pipelines are considered as a delivery mode, therefore making this model unsuitable to explore early states of transition to hydrogen when other transport modes are expected to be competitive, as discussed in Yang and Ogden [5]. In addition to the techno-economic specification, the model needs the following input: location and magnitude of hydrogen demand, location of potential hydrogen production plants, and a candidate pipeline network for connecting supply and demand.

Almansoori and Shah [2] model primary energy sources, production (Steam Methane Reforming, Coal Gasification, Biomass Gasification and Water Electrolysis), storage plants, and transportation through tanker truck or railway tank car. The mix between liquid and compressed gas hydrogen is however assumed exogenously. Penetration rates of hydrogen are constant across regions. In the objective function the authors sum costs, which are split in terms of production, storage, transportation, and primary energy sources, occurring in different years rather than discounting them to a common year before summing them up, which would be more appropriate. The model in Almansoori and Shah [2] has been improved by a number of authors by introducing the modifications described below.

2.1. Additional delivery modes

Pipelines and ships have been introduced by Han et al. [6] and Sabio et al. [7] but also by Kamarudin et al. [8] and Kim et al. [9] although no detailed description of the equations is provided in the last two articles. In Sabio et al. [7], pipelines are introduced in the model through an origin–destination matrix, implying that two neighbouring regions exporting to a third would require the construction of two completely distinct pipelines. Han et al. [6] introduce pipelines and ships by applying the subtour elimination constraints from the

[1] In order to ensure computability, a number of additional simplifications are introduced with regard to the potential pipeline links. No information is provided on how demand centres are selected.

Travelling Salesman Problem, although it is unclear whether this framework, implying that each geographical area needs to be delivered a certain good and that the delivery journey visits each area only once, is appropriate for any hydrogen delivery mode.

2.2. Multi-objective optimisation

Multi-objective optimisation has been implemented in Kim and Moon [10], Sabio et al. [7], Brey et al. [11], Hugo et al. [12] and in Li et al. [13] although the last three articles do not present a complete description of the model. All of these articles optimise the model through the familiar ε-constraint method. Kim and Moon [9] minimise total costs in the system alongside risk implied by the systems. Sabio et al. [7] adopt an objective function comprising nine variables, one related to costs, the other eight to Life Cycle Analysis indicators. Brey et al. [11] take into account cost, environmental quality and the preferences expressed by the government in relation to use of different energy sources. Finally, Hugo et al. [12] and Li et al. [13] take into account economic costs as well as Well-To-Wheel Greenhouse Gases Emissions.

2.3. Discounting costs

This appears to have been done only by Sabio et al. [7], where costs for each period are discounted back to a common time period and then summed, therefore avoiding summing costs sustained in different time periods.

2.4. Introducing stochasticity

Kim et al. [9] pair a stochastic specification of hydrogen transportation and demand with a deterministic specification of production and storage on the basis that the existing production and storage infrastructure will in practice supply a time-varying level of demand. Considering that the stochastic component implies at most a 1.7% change in the costs compared to a fully deterministic model, the practical implications of the stochasticity allowed in the article are minimal and probably dwarfed by the uncertainty related to the value of the cost parameters used in the study.

The model presented in this article is a refinement of Almansoori and Shah [2] introducing the following improvements:

- We develop a scenario of hydrogen demand across time informed by the outputs of an energy system model and developing at a rate comparable to historical precedents. We allow for different demand penetration rates across geographical areas, with the demand for each area determined by factors as income, cars per household and education. As far as we are aware this is the first study to combine analysis of the factors determining the possible spatial and temporal pattern demand for hydrogen with the optimisation of the infrastructure needed to deliver it;
- We allow for carbon capture technology at H_2 production sites and CO_2 delivered by pipes to a number of existing storage reservoirs. Konda et al. [14] is the only other example in the literature modelling pipelines for CCS, although the authors present only a qualitative description of the model. As far as we are aware this is the first time that equations for the modelling of CCS pipelines in a regionally-disaggregated MILP are published in the hydrogen literature;
- We simultaneously model both liquid (LH_2) and compressed gaseous hydrogen (GH_2), the split between the two being determined endogenously rather than assumed exogenously. This has been implemented by Han et al. [6] for a static model but we have not seen any author implementing it for a multi-period model;
- We use a discount factor formulation like the one discussed in Sabio et al. [7]. We also take into account of the fact that the implications of the fact that one time period in the model is representative of more than one year, as in Akgul et al. [15]. In order not to bias the optimisation, we also consider the remaining value of the hydrogen infrastructure which is subtracted from the total costs;
- We include filling stations needed to retail hydrogen to final consumers and allow for decentralised production technologies to be located at the station;
- We place the optimisation of HSC within the wider context of a scenario of optimal energy system evolution by using as inputs a number of outputs, notably introduction year of hydrogen, level of CO_2 tax and CO_2 intensity of electricity, from a MARKAL energy systems model developed for the United Kingdom;
- We adopt a modified ‘neighbourhood flow’ approach, which has been developed based on that described in Akgul et al. [16] and developed a hierarchical approach to solve the large scale model introduced in this paper which substantially improves the computational efficiency, and hence enables greater model complexity.

3. Model description

In this section we succinctly discuss the specification and the components of the model. A more detailed description can be found in the appendices which can be downloaded as Supplementary material.

3.1. Mathematical specification

The optimal design of a hydrogen supply chain involves several decisions, including locations, technologies and scales of hydrogen production plants, storage and filling stations, and transport system characteristics. The overall hydrogen supply chain problem under consideration is stated as follows. Given:

- hydrogen demand in each region and time period;
- characteristics of hydrogen production technologies, storage, filling stations, transportation modes and CO_2 pipelines;
- carbon tax per unit of CO_2, carbon emission and capture factors;
- locations of the CO_2 collection points and reservoirs, reservoir capacities and their connections to the collection points;

SHIPMod determines in each time period the optimal:

- location, scale and type of hydrogen production plants, storage facilities, filling stations, and transport models, as well as location and size of onshore and offshore CO_2 pipes;
- hydrogen production rates and stored amounts;
- flows of hydrogen and CO_2 between regions, and CO_2 flows between collection points and reservoirs, as well as CO_2 inventory levels of the reservoirs.

So as to minimise the total supply chain network cost (TC) which consists of facilities capital cost (FCC), CO_2 pipelines capital cost (PCC) and transportation capital cost (TCC), facilities operating cost (FOC), CO_2 pipelines operating cost (POC), transportation operating cost (TOC) and cost of carbon emissions (CEC) terms as follows:

$$TC = FCC + PCC + TCC + FOC + POC + TOC + CEC \qquad (1)$$

The objective is minimised with respect to demand, production, storage, filling stations, transportation and CCS constraints. The details of the mathematical formulation are given in Appendices A and B.

SHIPMod adopts a modified "neighbourhood flow" representation for the purpose of problem size reduction and computational efficiency. In this approach, which has been developed based on the work of Akgul et al. [16], a material can flow from the origin to the destination point by the addition of sequential neighbourhood flows. This approach is introduced into the mathematical formulation through a set, $N_{gg'}$ which is defined as:

$$N_{gg'} : (g, g') \quad \text{where} \quad L^{R}_{gg'} \leq L^{R}_{gg''} + L^{R}_{g''g'} \quad \forall g \neq g' \neq g'' \in G \qquad (2)$$

For each region g, this set includes its immediate neighbours as well as those where the direct distance from region g to g' is less than or equal to the total distance travelled when following a different route through regions g, g'' and g' with the same start point g and destination point g'. Due to the high computational requirements, the model is solved using a hierarchical approach which consists of two steps, as illustrated in Fig. 1. In the first step, we treat 3 integer and binary variables as continuous and we solve the model to determine the location, scale and technology of production plants in the last time period, defined through the variable: $NP_{jpig,T}$. The variables treated as continuous, which have been chosen on the basis of highest impact on computational time, are:

- U_{mgt}: binary variable that represents establishment of $m-1$ production facilities in region g in time period t;
- NS_{spigt}: integer variable that represents the number of storage facilities of type s and size p located in region g in time period t; and
- NF_{fpigt}: integer variable that represents the number of filling stations of type f and size p located in region g in time period t.

In the second step, we compute the optimal evolution of the supply chain network configuration through time after fixing NP_{jpigT}. for the last time period, $t = T$, according to the solution from the step above. The optimality gap is set to 5% and to 1% for the first and second steps of the proposed hierarchical approach, respectively.

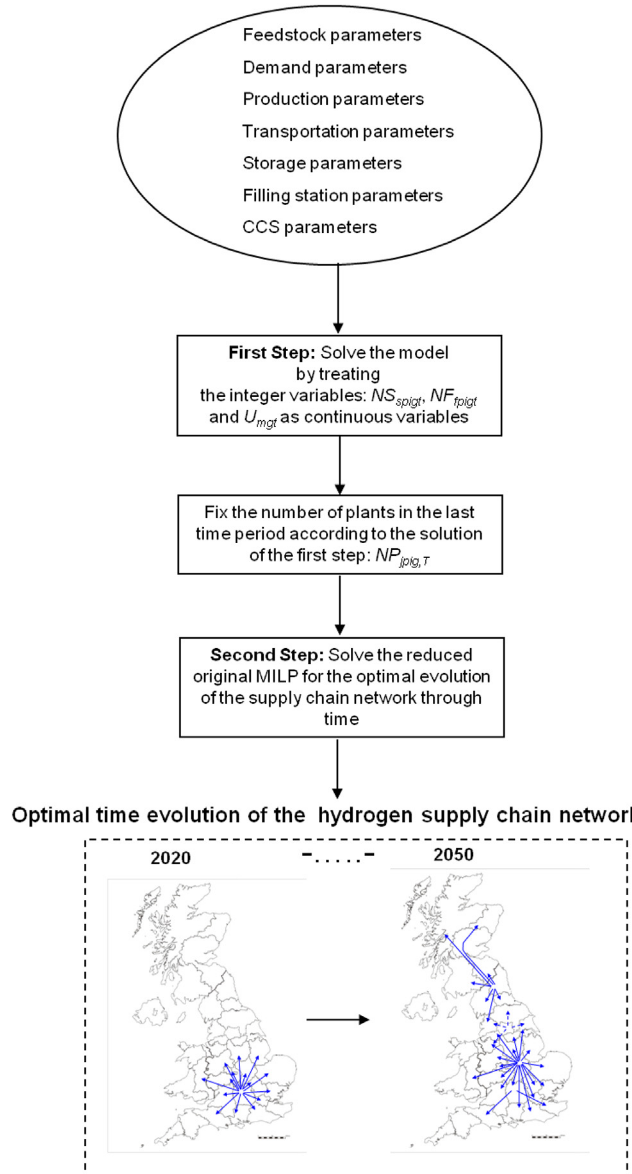

Fig. 1 – Illustration of the solution procedure through the proposed hierarchical approach.

3.2. *Model components*

The components of SHIPMod are regions; physical form of hydrogen, i.e. liquid (LH_2) and compressed form (GH_2); production and storage technologies allowing for different plant sizes; transportation modes to distribute hydrogen across regions; filling stations of different types and sizes; and finally CO_2 capture and infrastructure needed to dispose of it into the reservoirs. The remainder of this section briefly discusses each component of the system and explains how the relevant parameters have been obtained.

3.3. Regions

The regions in this study are based on the NUTS 2, a widespread taxonomy used by the Office for National Statistics and other governmental bodies. The list of the regions can be seen in Table C1 in Appendix C.

3.4. Physical forms of hydrogen

The model presented in this article allows for simultaneous modelling of compressed gas (GH_2) and liquid form (LH_2). LH_2 benefits from cheaper storage and transport but requires liquefaction, an expensive process both in term of capital and operational costs.

3.5. Production technologies

Following a number of articles in the literature, for example Ref. [2], we select four technologies for hydrogen production in SHIPMod, i.e. Steam Methane Reforming (SMR), Coal Gasification (CG), Biomass Gasification (BG) and Electrolysis. We consider existing production for hydrogen, facilities through the NP^0_{jpig} variable in the model. Other production technologies including hydrogen from waste and biological hydrogen have not been included so far in SHIPMod, as we feel that the former may have only a relatively small role in the UK while the latter is at a relatively early technological stage implying considerable uncertainty with regard to costs estimates. It is worth mentioning that different technologies which could be used in the production of electricity, in particular, wind and solar, are not considered explicitly, although they might be introduced in SHIPMod by having several prices for electricity, one for each technology used in the production factor. Although this would be a promising approach to take into account surplus electricity from intermitting sources which would not be used in the power system unless it can be stored by hydrogen or any other storage medium, this is not implemented in the current version of SHIPMod. In the case of SMR, CG and BG the model incorporates plants with and without Carbon Capture and Sequestration (CCS). For each technology we consider both plants producing GH_2 and LH_2, the obvious difference being a liquefaction plant added to the latter. Considering the additional technical component and electricity requirement, LH_2 implies higher capital costs and unit production cost than GH_2. In terms of size this article includes distributed, small, medium and large plants.

Values related to minimum and maximum production capacities of the plants are presented in Table D2 in Appendix D. The values of the capital costs in Table D1 for GH_2 are taken from Refs. [17,18] with the exception of the values for Medium SMR and Small BG which are taken from Refs. [19,20], respectively. The values for LH_2 comprise the capital of the production and of the liquefaction plant. Costs for liquefaction units are taken from Ref. [20]. All values have been scaled to the maximum capacity of each plant in Table D1 based on the size factors from Ref. [17]. In terms of Unit Production Cost (i.e. the sum of fuel and operating costs per unit production), we have implemented the techno-economic analysis described in Appendix C of Almansoori [21]. We have updated the values in Ref. [21] to include the capital costs described above as well as primary sources prices which are more reflective of the current and expected future market conditions. Natural gas price used in the analysis is 1.9 p/kWh, i.e. the average price paid by UK interruptible consumers, i.e. the consumer paying the cheapest price, over the period 2008–2011 [22]. Note that this implies a price of 8.2 Dollars/Million BTU against the 2.5 used in Ref. [21]. The electricity price used in our computation is 5.4 p/kWh from Ref. [22] which implies about 0.08 USD per kWh against the 0.05 assumed in Ref. [21]. Resulting Unit Production Costs are shown in Table D3.

3.6. Transportation modes

Two transportation modes are considered in SHIPMod: trailers transporting GH_2 and tankers transporting LH_2. As one can see in Table D4 in Appendix D, tankers are almost twice as expensive as trailers although they are much cheaper per transported unit. Most of the parameters from Table D4 are taken from Ref. [2] with the exception of the price of the fuel used by trailers and tankers which is set at the dollar equivalent of 1.50 British pounds per litre, minimum flow rate which is set equal to the size of a single unit as described in Ref. [20], and capital costs which were also sourced from Ref. [20].

3.7. Storage plants

Storage parameters have been sourced from the US H_2A database [23]. As one can see in Table D5 in Appendix D storing GH_2 is considerably more expensive than storing LH_2, a factor which helps offset the cost of liquefaction needed to produce LH_2.

3.8. Filling stations

Three types of filling stations are considered in SHIPMod, namely stations receiving LH_2 by tanker, stations receiving GH_2 by trailer and finally stations with an on-site production plant. In all cases, hydrogen is retailed in GH_2 form for use in passenger vehicles. In the case of stations with on-site production plants we consider only large stations, while in the other two cases we consider small, medium and large stations, i.e. servicing a maximum of 72, 167 and 333 cars per day. As one can see Table D6 in Appendix D, stations receiving LH_2 are considerably pricier than stations receiving GH_2, due to the former requiring high pressure storage, LH_2 storage, evaporators and cryogenic compressors. Stations receiving hydrogen delivered by tube trailer are cheapest, as they are assumed not to require onsite storage (which is instead provided by the delivered hydrogen tubes, the cost of which is represented in the cost of tube trailers rather than in the fuelling station cost). Stations with on-site production are more expensive due to the required onsite storage. Note that the cost of the hydrogen production technologies that must be installed adjacent to stations with on-side production is not included in the capital cost of the station, but rather in the cost of the production technologies shown in Table D1. The technical specification of the filling stations can be seen in Table D7.

3.9. CO_2 emissions

CO_2 emissions from hydrogen production depend on the carbon content per MJ of the energy sources used in the production process; the efficiency of the plants – mainly sourced from Ref. [17]; the electricity consumption of the plant; whether the hydrogen is produced in liquid or compressed gas form; and finally; whether CO_2 is being sequestered or not.

Table E1 in Appendix E shows the emission factors of electricity which were taken from the MARKAL scenario presented in Dodds and McDowall [24]. For each plant and technology type in this study, Figs. E1 and E2 display the amount of CO_2 emitted per kg of H_2. Fig. E3 shows the amount of CO_2 sequestered per kg of H_2 in the plants fitted with CCS. In order to sequester CO_2, SHIPMod assumes that one has to build on-shore pipes from the plant up to the collection points and off-shore pipes from the collection points to the reservoirs. The capital cost of on-shore and off-shore CO_2 pipes was modelled through a linear relationship between cost per km and diameter of the pipelines which was obtained as an average of the two curves (high and low) for offshore and onshore pipes described in Ref. [25]. Collection points are on-shore locations near the reservoirs from where offshore pipelines reaching the reservoirs begin. Following Ref. [26] this paper takes into account three CO_2 reservoirs around the UK. Maximum capacity for each reservoir was sourced from Ref. [27]. Table E2 shows the CO_2 reservoirs modelled in this study and the regions where collection points for each reservoir are located.

Finally, a tax on CO_2 emissions is introduced based on the results from the MARKAL runs presented in Ref. [24]. The level of the tax corresponds to the marginal abatement cost within a least-cost energy system transition that meets the UK's carbon reduction targets. The level of the tax is thus consistent with the carbon intensity of electricity, which is drawn from the same MARKAL scenario. The level of the tax across years is shown in Fig. E4.

4. Total demand for hydrogen

In order to generate a plausible scenario of diffusion of hydrogen into the transport sector, we adopt a logistic diffusion model [28] and following the main view from the literature – see for example Ref. [2] or Ref. [10] – we assume that hydrogen vehicles can ultimately reach 100% of the stock. Following Agnolucci and McDowall [1] we temper the optimism in the literature by selecting a hydrogen demand scenario (namely the 'high policy support, modest learning scenario' scenario from the HyWays European Hydrogen [29]) that does not postulate introduction of hydrogen unfolding at a quicker pace than those observed in historical analogies (for a discussion of rates of transition for alternative fuelled vehicles, see Ref. [30]).

As described in Agnolucci and McDowall [1], we use an energy systems model, namely UK MARKAL, to provide an indication as to when hydrogen might be introduced so that the transition is consistent with a broader analysis of cost-optimal decarbonisation trajectories. MARKAL inputs are taken from the scenario presented in Refs. [24], in which hydrogen FCVs become cost-effective from 2040 onwards. As some consumers are likely to be less price-sensitive and eager to adopt new, innovative technologies beforehand, transitions from energy system model like MARKAL are likely to be conservative with respect to the date of market entry (see Ref. [30]). As studies on the diffusion of innovations [28] have suggested that around 2.5% of consumers are likely to act as 'innovators', we assume that a 2.5% market share (of such 'innovators') can be reached in 2035 and we propose a logistic curve with the parameter estimated from the aforementioned scenario in HyWays and passing through 2.5% market share in 2035.[2]

4.1. Spatial distribution of hydrogen demand

A number of factors related to the technological specification of the vehicles and the socio-economic characteristics of the adopters are expected to be relevant in the adoption of FCVs [32]. Among the attributes discussed in Melendez and Milbrandt [33], we consider access to cars, education, commuting distance and household income. All of these attributes are expected to have a positive impact on the diffusion of FCVs. We also believe that the diffusion of FCVs will be facilitated by high population density – higher number of potential adopters which can be served by a given infrastructure – and size of the population as it can be considered as a proxy for market size [34].

Data to implement the socio-economic attributes above – see Table 1 – were collected from the latest available UK Census.[3] Following Ref. [33], scores from 1 (least favourable to hydrogen) to 5 (most favourable to hydrogen) for each attributes used in the study were constructed (by using the ClassInt package in R) for each geographical area and combined into one single mark for each area by simple averaging. The results from the scoring exercise are shown in Table C1 in Appendix C and graphically in Fig. 2. Hydrogen is expected to penetrate the passenger transport sector first in the South East of England and then develop along a corridor going from Manchester to London, including all the areas in between, with the exception of West Midlands. The third group of area in the hydrogen uptake includes Wales, some parts of Northern England and West Midlands. The next group of areas comprises large parts of Scotland, South Yorkshire in the North, Devon in the South West, and Northern Ireland. Finally, the last group of areas comprises the area at the very South West and North of the UK as well as those in the very north of England. It is interesting to notice that our score based on socio-economic factors also generates a scenario

[2] As this logistic implies over 50,000 vehicles in 2010, based on the UK vehicle fleet of 30 million vehicles (see Ref. [31]), we assume that 10,000 vehicles enter the market in 2020, and the number of FCVs grows linearly to 2035, at which point it reaches a 2.5% market share. From that point onward, we assume logistic growth, until all passenger market is taken by hydrogen.

[3] Data can be found in Ref. [35] for England and Wales, in Ref. [36] for Northern Ireland and in Ref. [37] for Scotland. As each attribute implies the use of three different variables defined in the Census, one for each group of countries comprised in the United Kingdom, the detailed sources of the variable used in the study are not mentioned here, although they are available upon request.

Table 1 – Socio-economic attributes thought to influence the adoption of hydrogen vehicles and related variables.

Attribute	Variable
Access to cars	Percentage of households with two or more vehicles
Education	Percentage of population with higher level qualifications
Commuting distance	Average commuting distance per person in miles
Household income	Gross disposable household income per head at 2001 basic prices
Population	Number of persons
Population density	Number of person per hectare

with spatial continuity in the diffusion of hydrogen although this was by no means guaranteed by the adopted approach.

Information from the ranking above is used to assign a set of 5 logistics to the geographical areas described above. Hydrogen is introduced in the most promising areas in 2020 and in the least promising ones 10 years later. Based on the typically faster rate of diffusion in late adopting regions [38], catching up occurs through a higher growth rate in the logistics for the area where hydrogen is introduced at a later stage. In order to compute hydrogen demand we have estimated million passenger kilometres for each area by allocating traffic figures from Refs. [31,39] for Great Britain and Northern Ireland, respectively, on the basis of data on commuting distance. Given the traffic figures for each area, the logistics have been applied to identify the passenger kilometres travelled by using hydrogen from which we computed hydrogen demand by using efficiency for FCVs from Ref. [40]. The result of this procedure is shown in Fig. 3.

5. Description of scenarios

A number of scenarios have been developed using SHIPMod to test the implications of major uncertainties in the development of a hydrogen transportation system. The baseline scenario uses the hydrogen fuel demand projections, resource costs and technology characteristics outlined in the previous sections. In addition to the base case, four alternative scenarios described in Table 2 have been generated to examine uncertainty related to hydrogen demand characteristics and evolution, and technology and resource availability. As pointed out by a referee, the main driving factor to introduce hydrogen as transportation fuel is to enable its decarbonisation. In order to reach decarbonisation, hydrogen may be produced by wind and solar plants, both of them requiring electrolysis. The fact that this production technology is never selected by SHIPMod implies that renewable electricity will be cost-competitive only if power from wind and solar plants is cheaper than the power price used in this study. This may well be the case for wind from particular good locations or surplus renewable electricity which cannot find any other use in the system. Renewable electricity will generally be more costs competitive in the future due to technological learning, economies of scales and increased carbon price. As an extension of the current work it would be particularly interesting to assess the electricity price at which electrolysis is selected by SHIPMod and discuss the implications in term of the cost of renewable electricity.

6. Discussion of results

6.1. *The base case: production and costs of hydrogen*

Hydrogen production in the base case is dominated by SMR with CCS and medium-sized biomass gasification plants (see Fig. 4). A marginal role is played by distributed and small SMR plant without CCS. No hydrogen is produced via electrolysis or from coal with CCS. The early phases are dominated by medium-sized biomass gasification plants although a number of distributed SMR plants are also built. In 2035, demand has risen sufficiently to support a large SMR plant with CCS. As demand grows and SHIPMod is able to benefit from scale economies arising from larger production facilities, undiscounted costs per unit hydrogen fall over time.

6.2. *Patterns across space: the trade-off between production scale and transport costs*

The spatial pattern of hydrogen demand results in trade-offs between production and transportation costs with larger plants producing hydrogen at a lower cost but incurring higher transportation costs. Faced with this trade-off, SHIPMod shows a tendency for large production facilities located in central regions in or close to regions with high demand, where they are able to service a considerable demand within relatively short distances. Small and distributed production facilities are established in peripheral regions where transport costs become prohibitive. This is clearly illustrated in the base case (see Fig. 5) although the overall patterns of hydrogen production are similar in most scenarios with the exception of the high demand scenario where the majority of hydrogen is produced from medium-sized bio-hydrogen plants which are more cost-effective than large plants due to the very small distribution area they need to cover due to the relatively high demand in this scenario.

Examining hydrogen flows between regions as a proportion of total hydrogen production (Fig. 6) shows that most hydrogen is not produced locally but delivered to the region by tanker or trailer. The exception is the ‘clustered demand’ scenario, which sees no trucked hydrogen in the first period, because production facilities are located in the regions where hydrogen is first deployed, i.e. regions containing the UK’s largest urban centres. The importance of distribution grows over time in this scenario, like in many of the other scenario, with the exception of the high demand scenario where medium-sized local plants become cost-effective leading to a declining share of trucked hydrogen as time goes by.

The importance of transportation—and in particular transportation costs—is also clear from an examination of the hydrogen form, LH_2 and GH_2, chosen by SHIPMod. As most scenarios are dominated by LH_2 produced in large centralised plants, the additional transportation costs of GH_2 are clearly more important than the additional liquefaction costs, with the exception of peripheral regions such as Northern Ireland

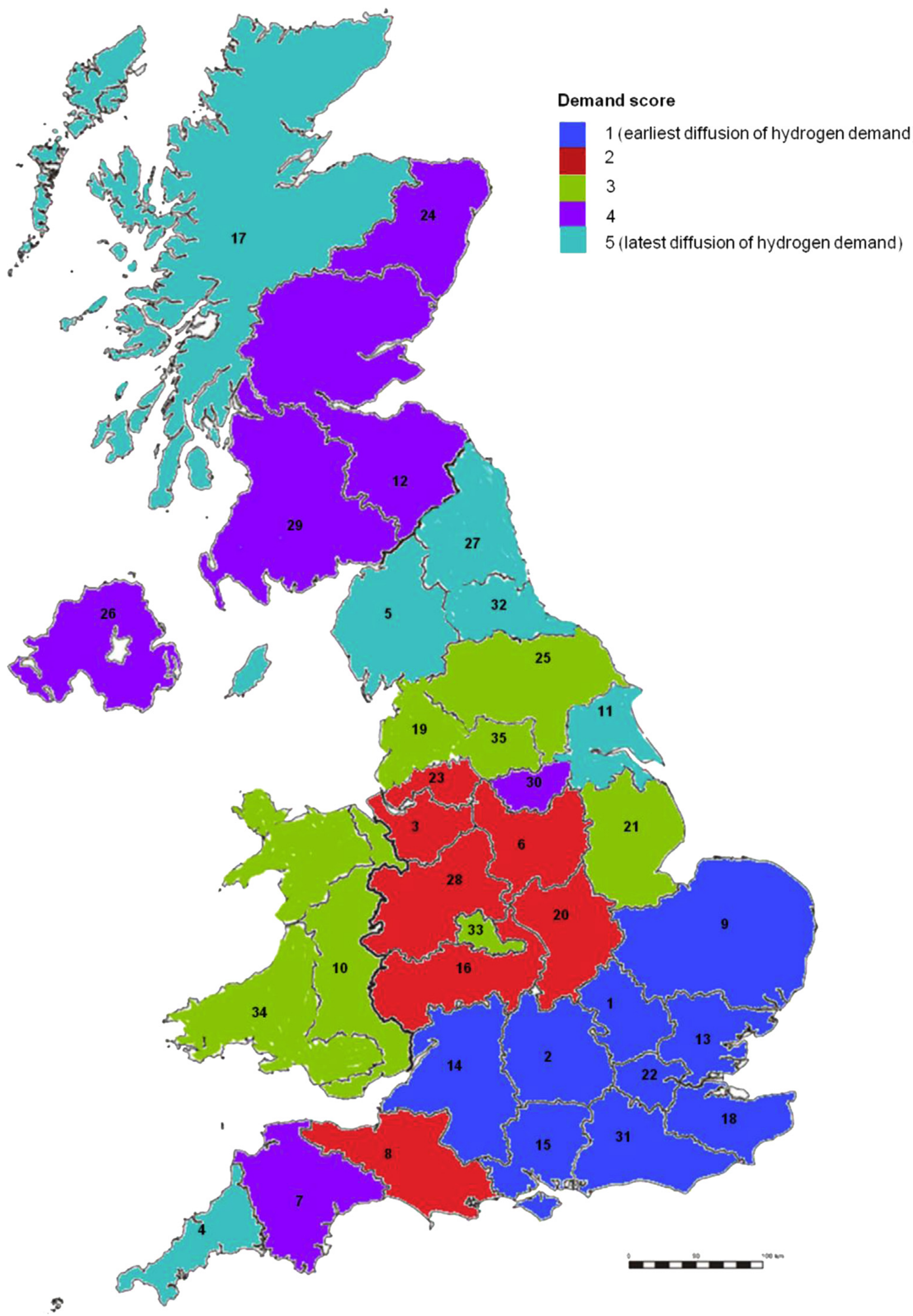

Fig. 2 – Geographical areas considered in this study. Shading indicates the demand score, while the numbers provide a key to region names, provided in Table C1.

and Cornwall, where small quantities of GH_2 are produced in distributed plants. Two scenarios present revealing exceptions to this overall trend. In the high demand scenario there is sufficient demand in a number of regions to support medium-sized biomass gasification plant. As imports decrease as time goes by, the model prefers to build cheaper GH_2 production plants rather than LH_2. In the clustered demand scenario, SHIPMod builds relatively cheaper GH_2 production plants to satisfy demand in the major demand centres. However, demand in late-comer regions is met either by local production from small distributed SMR plants, or from two LH_2 plants, one built in the north of England, another in south-central England.

The spatial pattern of demand across regions has also a strong effect on costs, as illustrated in Fig. 7. The total discounted costs of hydrogen supply are 10% higher in the diffuse

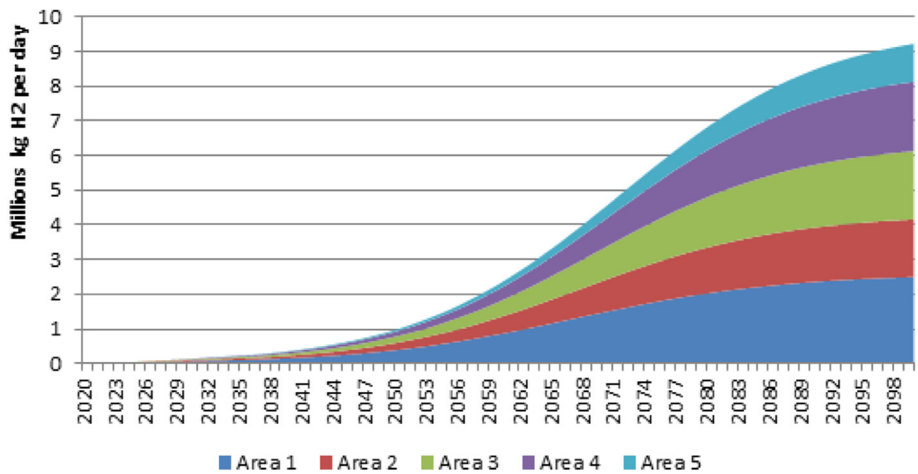

Fig. 3 – Daily demand for hydrogen split according to order of areas penetrated by hydrogen.

scenario compared with the clustered one. This cost differential is particularly large in the early periods, with the costs per kilogram of hydrogen in the diffuse scenario 25% greater than in the clustered scenario.

As a result of the trade-off between production costs and transport costs, the low level of demand and its spatial dispersion, the model leaves significant production capacity unused in all scenarios. This result is driven by scale economies associated with larger plants and the costs associated with transporting hydrogen from one region to another which prevents the model from simply building a single large plant, and using it to maximum capacity by exporting hydrogen to all the other regions. Due to the large difference between minimum and maximum production capacity, large plants may become cost effective compared to smaller plants despite leaving a considerable amount of capacity unused. This results in a pattern by which spare capacity falls as demand grows until a threshold is crossed for an additional investment in a large new plant, which increases the space capacity (see Fig. 8). This high level of spare capacity is a logical feature of a system that is required to meet low and spatially diffused demands that are characteristic of the early stages of an infrastructure transition. This point tends to be well known by those investigating the deployment of hydrogen refuelling technologies, but is often not well represented in systems models, such as the MARKAL/TIMES family of models, that lack detailed spatial disaggregation and integer variable representing investments.

Table 2 – Scenarios discussed in this study and their characteristics.

Scenario name	Scenario characteristics	Reason for inclusion
Base case	The base case scenario is using the technologies and demand characteristics as described in Section 3.	A base case against which other scenarios can be compared.
Diffuse demand	Total demand for hydrogen is the same as the base case, but in this scenario it is equally apportioned to each region, based on population.	Assessing the impact of geographical dispersion of demand on the optimal configuration of the system.
Clustered demand	Total demand for hydrogen is the same as the base case, but demand is spatially clustered on ‘leading’ regions, i.e. the four major urban regions: London, the West Midlands, south-west Scotland, and Manchester-Merseyside. Demand outside of these regions is built up later and more slowly.	
High demand	Demand is increased five-fold, but with the same spatial distribution as the base case. This results in a demand trajectory within the range of those discussed in the literature, but with a much faster rate of deployment than in the baseline.	Assessing the impact of the level of demand on the optimal configuration of the system.
No biomass	Same as the base case, but with no biomass available for H_2 production.	Assessing the optimal configuration of the system in case biomass was not available – included because of the observed importance of hydrogen production from biomass in model runs.

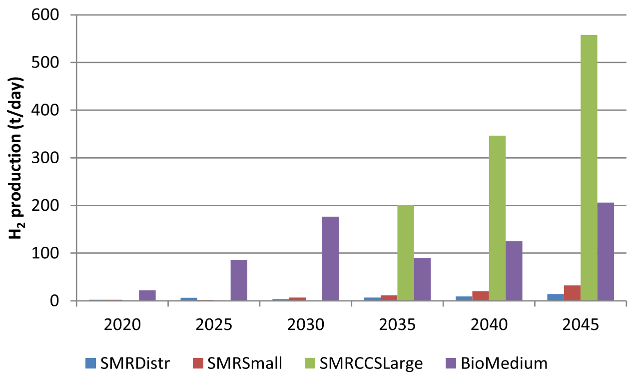

Fig. 4 – Hydrogen production in the base case scenario.

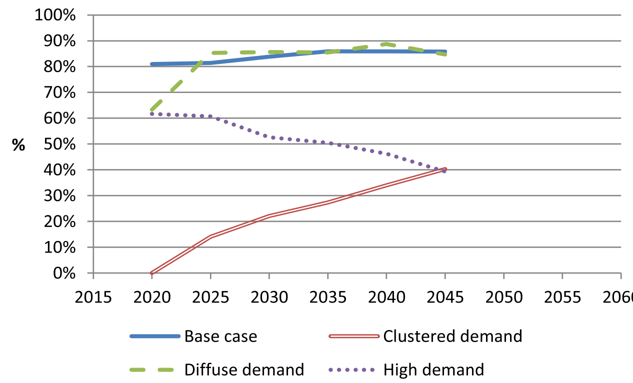

Fig. 6 – Proportion of production that is transported between regions (%) rather than produced locally, in different scenarios.

6.3. *Technological uncertainties: roles of bioenergy and CCS*

The ‘no biomass’ scenario results in a complete reliance on natural gas for hydrogen production, with SMR plants of various sizes built across the country. In this scenario, SHIPMod introduces CCS much earlier than in other scenarios, and at a smaller scale, building two medium-sized SMR–CCS plants by 2025, as well as a single large SMR–CCS plant later on. This is unsurprising, as unabated small and medium SMR plants would incur excessive carbon costs, and electrolysis still incurs relatively high carbon costs until the grid has decarbonised from around 2030. In terms of the evolution of CCS plant and pipeline capacity, see Fig. 9, an initial medium SMR–CCS plant is built between major centres Birmingham and London in 2020, with a pipeline taking CO_2 to the reservoir in the southern North Sea. In 2025, an additional medium SMR–CCS plant is constructed in Lancashire. By 2035, sufficient additional demand has developed to justify a third, and now large SMR–CCS plant in central England. This additional plant makes use of the existing CO_2 pipeline capacity, and is constructed on the route of the pipeline to the southern North Sea reservoir.

6.4. *Limitations of the analysis and areas of further research*

In interpreting the results, it is important to highlight a number of limitations of SHIPMod. Firstly, there is the general caution that—as with any optimisation model exploring

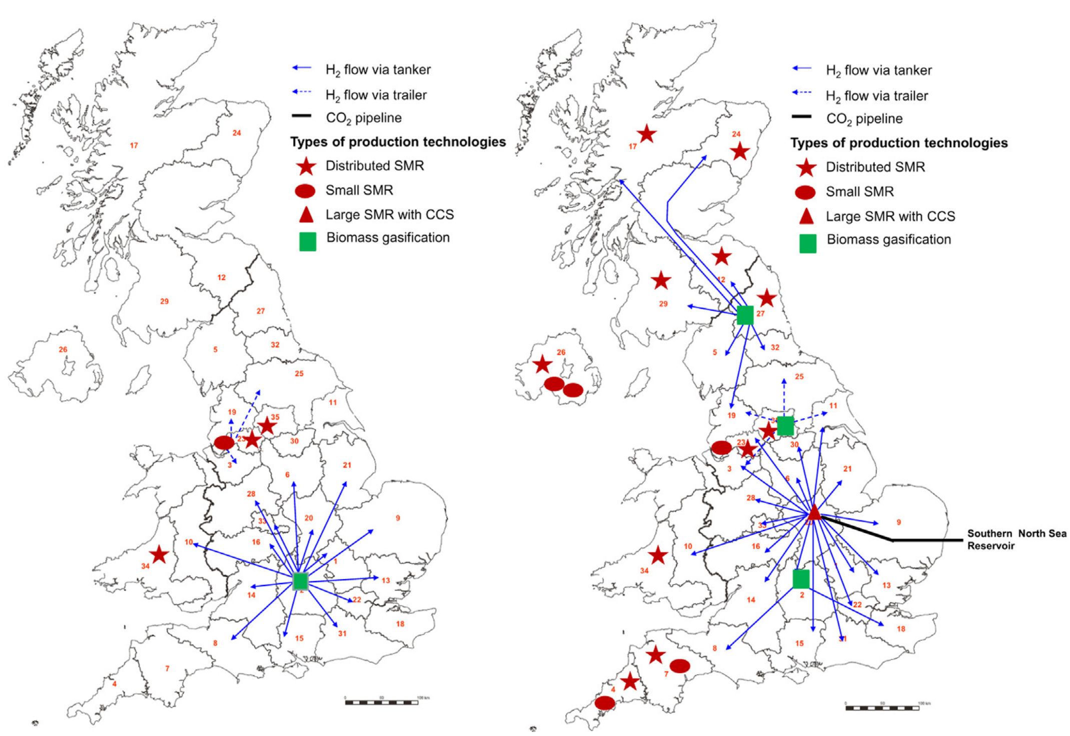

Fig. 5 – Evolution of supply in the base case scenario (first and last model period).

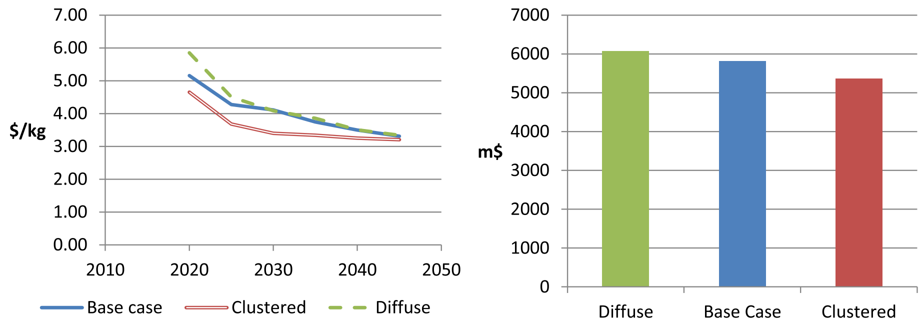

Fig. 7 – Undiscounted costs of delivered hydrogen over time in different scenarios (left) total discounted costs across the model time horizon (right).

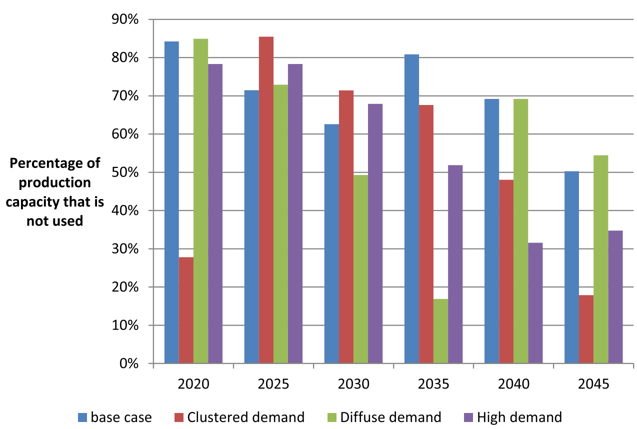

Fig. 8 – Spare capacity as a proportion of total capacity.

possible future scenarios—the input data is all highly uncertain. Secondly, the model does not include hydrogen pipelines, a major option for hydrogen infrastructure. We plan to address this omission in future work. As the inclusion of hydrogen pipelines may enable more cost-effective use of large, centralised hydrogen production technologies by reducing long-distance high-volume transport costs, the omission of such pipelines may cause an overstatement of the costs of hydrogen presented here, and of the levels of un-used capacity.

More fundamentally, the reliance on an exogenous hydrogen demand curve is a clear limitation of this type of approach. Fuel demand is strongly influenced by its costs, relative to the other options, but the use of an exogenous demand forecast prevents any feedback between supply and demand. In this paper, we have attempted to improve on previous modelling practice of HSCs by deriving demand assumptions from a coherent analysis of energy system possibilities, and by ensuring that demand assumptions are thus consistent with other key parameters such as carbon prices and the carbon intensity of electricity through the use of the results from the MARKAL run described in Dodds and McDowall [24]. However, it would be preferable to soft-link the SHIPMod to the energy systems model, so that H_2 demand can respond to the infrastructure costs generated by SHIPMod. This would require iteration between the two models, building on the approach previously adopted by Rosenberg et al. [41].

A final point concerns the perfect-foresight formulation. As is typical in optimisation models of this kind, SHIPMod optimises over the full time horizon. In the real world, decision-makers do not act with perfect foresight. Rather, they hedge in the face of uncertainty, and those making risky investments require compensation for the risk that they take on—resulting in higher costs of capital. In effect, these risk effects may result in returns to scale: as a transition unfolds, investor confidence in the future success of hydrogen builds, and costs of capital fall. An alternative would be a completely myopic model, in which optimisation of each period took

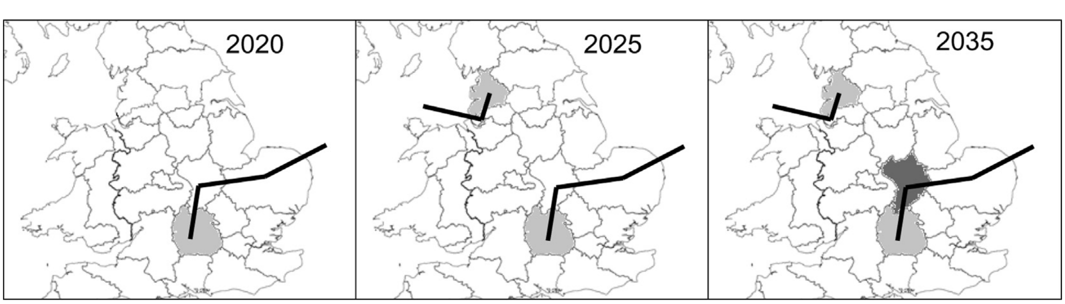

Fig. 9 – Evolution of the CCS network in the 'no biomass' scenario over the 2020–2035 time period. Black lines represent pipelines. Light shaded regions contain a medium-sized SMR–CCS plant. The dark-shaded region contains a large SMR–CCS plant.

place sequentially, although this would neglect the role of actor expectations about future trends.

7. Conclusions

This paper presented an optimisation-based framework for the design of hydrogen supply chain and CCS pipeline networks over a long planning horizon. The overall problem has been formulated as a multi-period, mixed integer linear programming model, while a hierarchical procedure has been proposed for tackling efficiently the resulting large-scale optimisation problems. We draw a number of conclusions.

First, despite some articles in the literature emphasising the potential for hydrogen to facilitate a decentralised energy system, our model shows a tendency for large production facilities. Small and distributed production facilities are established only in peripheral regions where transport costs become prohibitive. The trade-off between production and transportation costs is an important factor determining the preference for large plants, the consequent high levels of H_2 imported into most regions and the preference for liquid hydrogen, as its lower transportation costs more than compensate the costs of liquefaction.

Secondly, we discovered that varying the level and the spatial pattern of demand has significant impacts on both the optimal supply system and on the overall costs of delivered hydrogen. These are important results because demand assumptions—particularly the spatial pattern of demand—tend to be downplayed in the literature, despite having clear implications for transition strategies of hydrogen in the passenger vehicle sector. Highly clustered demand which is rather cheaper to service than highly diffused demand shifts the preference of the model to gaseous hydrogen rather than liquid hydrogen, due the lower importance of transport costs caused by shorter length of the average haul. Depending on the number of clusters and their relative size, medium-sized production plants can become more cost-effective than large plants because of the smaller need for transportation. Similarly, a high level of demand makes medium-sized production become cost-effective and hydrogen tends to be produced in gaseous form because of the relatively small catchment areas for each plant.

In term of model development, a clear way to improve the model presented here consists in the introduction of pipelines to deliver hydrogen. In addition, as result of our findings related to the effect of different spatial and temporal pattern of demand on configuration of Hydrogen Supply Chains, it would be beneficial to link SHIPMod with an energy system model in order to systematically assess the effect of different level of hydrogen demands resulting from an optimised energy system on the infrastructure required to meet that demand.

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Appendix A. Supplementary material

Supplementary material related to this article can be found at http://dx.doi.org/10.1016/j.ijhydene.2013.06.071.

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