

# Green hydrogen production and use in low- and middle-income countries: A least-cost geospatial modelling approach applied to Kenya

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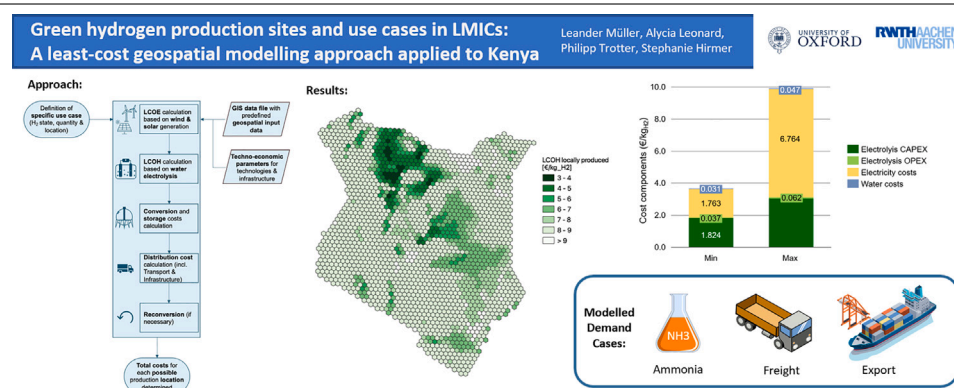
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## GRAPHICAL ABSTRACT



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## ABSTRACT

With the rising threat of climate change, green hydrogen is increasingly seen as the high-capacity energy storage and transport medium of the future. This creates an opportunity for low- and middle-income countries to leverage their high renewable energy potential to produce, use, and export low-cost green hydrogen, creating environmental and economic development benefits. While identifying ideal locations for green hydrogen production is critical for countries when defining their green hydrogen strategies, there has been a paucity of adequate geospatial planning approaches suitable to low- and middle-income countries. It is essential for these countries to identify green hydrogen production sites which match demand to expected use cases such that their strategies are economically sustainable. This paper therefore develops a novel geospatial cost modelling method to optimize the location of green hydrogen production across different use cases, with a focus on suitability to low- and middle-income countries. This method is applied in Kenya to investigate the potential hydrogen supply chain for three use cases: ammonia-based fertilizer, freight transport, and export. We find hydrogen production costs of €3.7–9.9/kg<sub>H<sub>2</sub></sub> are currently achievable across Kenya, depending on the production location chosen. The cheapest production locations are identified to the south and south-east of Lake Turkana. We show that ammonia produced in Kenya can be cost-competitive given the current energy crisis and that Kenya could export hydrogen to Rotterdam with costs of €7/kg<sub>H<sub>2</sub></sub>, undercutting current market prices regardless of the carrier medium. With expected techno-economic improvements, hydrogen production costs across Kenya could drop to €1.8–3.0/kg<sub>H<sub>2</sub></sub> by 2030.

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## 1. Introduction

The aim of this paper is to identify least-cost locations for the production of green hydrogen across varying use cases in a low- and middle-income country setting. We develop a novel spatial modelling method for the cost of green hydrogen along the entire supply chain, and we apply it to Kenya for use cases of ammonia production, freight transport, and export.

With the rising threat of climate change, efforts towards developing sustainable energy systems have gained momentum in recent years [1]. Renewable energy sources (RES), such as wind, solar, geothermal, and hydropower, have caught up with, and in many cases overtaken, conventional power generation technologies in terms of levelized cost of electricity. Indeed, they already make up significant shares of total electricity production in some regions such as Norway and Costa Rica [2]. However, RES generation technologies alone will not be able to fully transform total final energy consumption [3,4]. To overcome the intermittency and volatility of RES, storage solutions are needed. Alongside traditional high-capacity energy storage, climate-neutral energy carriers are required to decarbonize sectors where electrical energy and batteries are reaching their operational limits. For these reasons, hydrogen has generated high interest in recent years [4,5]. The possibility of climate-neutral hydrogen production via electrolysis using RES (known as green hydrogen), and the subsequent opportunity to utilize it in cross-sectoral applications as a chemical or energetic feedstock, make it a promising and sustainable energy solution.

While high-income countries are leading green hydrogen technology development and activities, low- and middle-income countries (LMICs) are increasingly interested in this field [6,7]. By producing green hydrogen domestically using their abundant RES (e.g., as exist in many African countries [6]), LMICs could meet domestic development goals by strengthening their own economies, increasing energy sovereignty, and becoming net energy exporters [7,8]. Care in such developments is needed, due to the risk of a renewable-based resource curse [9]. However, if governed well by institutions with incentives to ensure widespread benefits for the population [10], hydrogen production presents an opportunity for climate-compatible economic growth in LMICs.

### 1.1. Green hydrogen location planning background

To advance the planning of hydrogen projects, the best geospatial locations for its production and use must be identified based on economic, infrastructural, geological, demographic and resource endowment factors<sup>1</sup> [12]. While a quickly growing literature has emerged focusing on green hydrogen infrastructure, extant research exhibits three critical knowledge gaps, namely concerning: (1) finding adequate geospatially explicit opportunities for green hydrogen production plants at different scales; (2) integrating different supply points with different demand options for green hydrogen; and (3) identifying applications tailored towards low- and middle-income countries with high renewable energy potential. The scope of each of these gaps is outlined below within the extant literature.

*On gap (1):* While predominant mathematical optimization approaches for location planning of green hydrogen produce system-wide optimal solutions for hydrogen production networks [13], they are usually too computationally expensive to identify exact geospatial locations of low-cost green hydrogen production [14]. A number of multi-criteria decision making (MCDM) models have been developed, such as Abdel-Basset's framework for deciding between hydrogen production options [15] or Rezaei's fuzzy MCDM approach for evaluating developing capital cities as hydrogen production sites, which then uses

Homer for electrical system sizing [16]. However, these are designed primarily to evaluate a set of given or heuristically determined hydrogen production sites, and not over a whole region. Khan et al.'s integrated green hydrogen evaluation tool [17] presents a more general and open-source approach to evaluate green hydrogen production opportunities, but analyses this for particular zones of interest only (i.e., not uniformly across a geography) and is tailored to the context of Australia. The complexity of factors to consider for geospatial identification and planning of green hydrogen infrastructure imply the utility of geographical information systems (GIS) for exact location planning [18,19]. This allows to evaluate land suitability for green hydrogen production uniformly across a region, as in Messaoudi et al.'s work in Algeria [20] and Soha et al.'s work in Hungary [21]. However, GIS analyses are not limited to land considerations, but can also allow planners to conduct supra-regional cost analyses which evaluate different supply and demand centres while considering relevant geographic constraints. Early efforts towards geospatial hydrogen planning exist in the literature, including Gupta et al.'s assessment of levelized costs of hydrogen in Switzerland [22], Tlili et al.'s assessment of transport and supply chains in France [23], and work by La Guardia et al. [24,25] and Guzzini et al. [26] assessing levelized costs of hydrogen in Italy. These site-specific GIS assessments often only consider a small set of discrete geospatial locations without ability to extend to other geographies, or cover only one stage of the hydrogen production process (e.g., neglecting demand centres or use-case-specific costs). One study which does cover more of these options is Mah et al.'s framework and application in Malaysia, which considers hydrogen transport methods of compressed gas, cryogenic liquid, or LOHC [27]. However, this work focuses on optimizing the entire hydrogen electricity supply chain instead of identifying specific feasible projects, and only considers hydrogen supplied by solar photovoltaics. A generalizable and geospatially-explicit cost modelling framework using multiple renewable energy generation options, which allows for application in multiple geographies, use-cases, and transport options is therefore needed.

*On gap (2):* While integrating green hydrogen supply and demand modelling has been argued to be critical for optimally planning transitions towards green hydrogen [28,29], the extant quantitative planning literature has either not integrated demand options [20,22,30], or tailored them to one specific use-case. For instance, Tabandeh's analysis focusing on hydrogen refuelling stations (HRS) [31], Tlili et al.'s research on green hydrogen in the transport sector [23], or Samsatli's work on hydrogen in heating [32] are limited to a specific use case of hydrogen. The H2 Atlas produced by Forschungszentrum Jülich provides an accessible online GIS for hydrogen planning in West Africa, but only considers supply-side constraints [33]. Where more detailed consideration of economic and demand-side factors are taken into account, such as in the Hydrogen Financial Analysis Scenario Tool (H2FAST) from the United States National Renewable Energy Laboratory, geographic factors and existing infrastructures are not considered [34]. However, given the different economic constraints for each hydrogen use case, a framework that allows the consideration of different use cases is required.

*On gap (3):* Existing peer-reviewed research on green hydrogen infrastructure exhibits a considerable bias towards European countries [23,30,35] as well as cases in Asia [28,36,37]. Similarly to conventional energy systems planning work [38], there is a paucity of research addressing low-income countries in general, and specifically the sub-Saharan African region [8]. This is despite the fact that the International Renewable Energy Agency estimates that sub-Saharan Africa has the largest regional potential to produce green hydrogen for under 1.5 USD/kg by 2050, with 30 times higher potential than all of Europe [7]. Where cases in Africa have been discussed in the literature, they have focused mainly on macro-level analysis, such as the recent work by AbouSeada and Hatem [39] as well as the work by Oyewo et al. on continental Africa [40] and by Bhandari on Niger [29].

<sup>1</sup> It is worth noting that location-based plans must also be accompanied by a robust political and regulatory framework [11].

There is therefore a clear gap for a generalizable GIS-based green hydrogen production siting framework, which can be applied across different geographies and use cases, and which takes both supply and demand side techno-economic and geographic considerations into account.

### 1.2. Novelty of this study

To fill the three gaps discussed above, to the best of our knowledge, our study features the following three key novel features:

- Our generalizable and geospatially explicit model allows to identify least-cost green hydrogen production locations. An important and novel feature in the realm of GIS-based green hydrogen planning is its usage of H3 hexagons as areas of analysis [41]. As hexagons fill space optimally and are equidistant from their neighbours [42], this allows to apply the model to different scales (e.g., sub-national or continental) without requiring significant changes to the model. This is a key feature given the importance of green hydrogen infrastructure planning on a local and global scale [7].
- The geospatial planning model integrates hydrogen supply locations with different domestic and export-oriented use cases. The literature has demonstrated efficiency gains of integrated supply and demand planning of green hydrogen [23,31]. However, our work is the first to perform geospatially explicit green hydrogen system analyses for different types of domestic and foreign use cases as well as high-resolution supply options.
- Our study is the first peer-reviewed work to explicitly consider geospatial green hydrogen infrastructure siting in an LMIC. Our choice of Kenya underlines the relevance of such studies given Kenya's excellent renewable energy potential, comparably low cost of capital, and the country's efforts to introduce green hydrogen technologies domestically [43,44]. Our study responds to recent research calling for more country-specific studies in Africa to define robust energy transition pathways [8]. While Kenya is investigated here, the developed methodology can be used to analyse different country and regional cases. It is intended for use as a tool to analyse green hydrogen opportunities and demand cases in any country to support decision-making processes for high-level planning or policy development.

The remainder of this paper proceeds as follows. Section 2 introduces the geospatial hydrogen cost optimization method. The full model implementation is available on GitHub: <https://github.com/leandermue/GEOH2>. Then, Section 3 presents the results of applying this method in Kenya, including spatial levelized costs of hydrogen (Section 3.1) and least-cost production locations for three potential hydrogen applications (Section 3.2). These results are compared to current market prices and conditions and discussed in the context of future techno-economic improvements in Section 4. Finally, conclusions are offered in Section 5.

## 2. Methods

A spatial cost modelling method is developed to find least-cost locations of potential green hydrogen production to match any specified demand or use case. The components of this model are illustrated in Fig. 1. To the best of our knowledge, it is the first model specifically designed to spatially calculate the total cost of meeting hydrogen demand – from power generation to hydrogen production, conversion, and delivery – considering *different end-use cases* along the *entire supply chain* using techno-economic, geological and resource endowment input data.

Costs are calculated for each possible production site (i.e., each spatial sub-segment of the entire area of interest) using a GIS-based

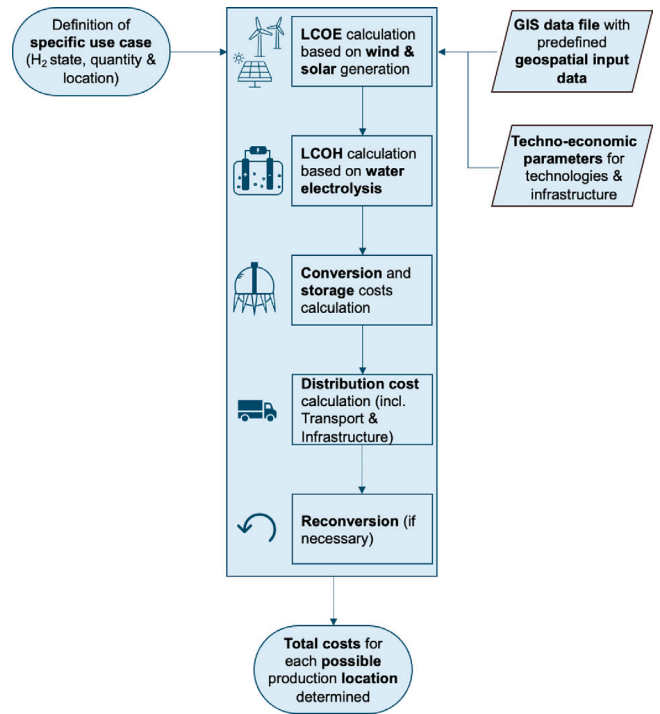


Fig. 1. Summary of the spatial hydrogen cost modelling method.

framework. This allows the identification of the least-cost supply location for any use case. In this model, use cases are defined in terms of the required state of the hydrogen needed, the quantity required, and the demand location. They could include hydrogen demands such as, for example, fertilizer production, long-term energy storage, or steel manufacture, among many others [45]. By determining the least-cost option for every supply chain step, holistic hydrogen costs at any selected demand centre are determined a least-cost production location is selected.

This method exclusively models the value chain of *green* hydrogen (i.e., produced via electrolysis with RES), as producing hydrogen in this way promotes both sustainability and international economic independence. Two renewable energy technologies are studied as means to generate the required electricity for production: newly constructed solar photovoltaics (PV), or onshore wind plants. These two technologies are, along with hydropower, the cheapest RES, and unlike hydropower, they are relatively quick and capital-efficient to set up [46].

The total cost of hydrogen from any particular supply location to any particular demand location is modelled as a sum of the following costs:

$$c = LCOH + c_{conversion} + c_{transport} + c_{storage} + c_{infrastructure} \quad (1)$$

where each  $c$  represents a different cost component as indicated by the subscript. Each of these costs is discussed in further detail in the following subsections.

### 2.1. Electricity generation

Electricity is required to produce green hydrogen. The levelized costs of energy ( $LCOE$ ) for this are calculated as:

$$LCOE = \frac{\sum_{t=1}^n \frac{CAPEX_t + OPEX_t + F_t}{(1+r)^t}}{\sum_{t=1}^n \frac{E_t}{(1+r)^t}} \quad (2)$$

where  $CAPEX$  represents capital expenditures,  $OPEX$  represents operational expenditures,  $F$  represents fuel expenditures,  $E$  represents

electricity generation,  $r$  represents the discount rate, and  $n$  represents the lifetime of the system in years. Values with the subscript  $t$  are relevant to the year  $t$ . We assume no fuel input is required for PV and wind generation plants, so  $F_t$  is set to zero. The discount rate is assumed to be constant over the time horizon.  $CAPEX_t$  and  $OPEX_t$  are calculated as an annual payment per power capacity (kW) and the generated electricity is assumed to be unchanged over the lifetime of the system. This simplifies the calculation to:

$$LCOE = \frac{\frac{CAPEX}{PVF} + OPEX}{E} \quad (3)$$

where  $PVF$  represents the present value factor ( $PVF = \frac{(1+i)^n - 1}{i}$ ) with interest rate  $i$  assumed to be 8% for all equipment [47].

Electricity generation is estimated using spatial data for PV potential from the Global Solar Atlas [48] and mean wind speed at a height of 100 m from the Global Wind Atlas [49]. To determine the annual generation from the PV systems, the average power potential data per year (kWh/kWp/a) is taken. To calculate a similar energy index (kWh/kW/a) for a wind turbine, an assumption had to be made about the actual selected wind turbine and the wind distribution within a year. The power output of a wind turbine can be calculated as:

$$P_t = \frac{\rho}{2} \cdot \pi \cdot r^2 \cdot c^3 \cdot c_p \cdot \eta_{field} \cdot \eta_{avail} \quad (4)$$

where  $P_t$  represents the power output of the turbine (maximum at nominal power),  $\rho$  represents air density,  $r$  represents rotor radius,  $c$  represents wind speed,  $c_p$  represents the power coefficient,  $\eta_{field}$  represents field efficiency, and  $\eta_{avail}$  represents availability. To represent the wind distribution more realistically than an average value, the Rayleigh distribution is used [50], which approximates the wind speed probability density function  $F(v)$  based on the average wind speed as:

$$F(v) = 1 - e^{-\left(\frac{v}{A}\right)^2} \quad (5)$$

where  $v$  represents the wind speed and  $A$  represents the scale parameter, defined as:

$$A = v_m \frac{2}{\sqrt{\pi}} \quad (6)$$

where  $v_m$  represents the mean wind speed. After calculating the  $LCOE$  for both technologies, the least-cost technology is selected for each potential production site. The exchange of electricity is allowed via the existing electricity network; therefore, the lowest  $LCOE$  of all sites connected to the grid is determined and defined as  $LCOE_{grid}$ . If electricity is purchased via the grid, a fixed transmission fee (in €/MWh) is charged. The most economic  $LCOE$  is selected for all locations, and thus a decision is made between  $LCOE_{wind}$ ,  $LCOE_{PV}$ , and – in the case of a location connected to the grid –  $LCOE_{grid}$  for each considered production location.

## 2.2. Green hydrogen production

Green hydrogen production is modelled as undertaken through water electrolysis, an endothermic chemical process which splits water ( $H_2O$ ) into hydrogen ( $H_2$ ) and oxygen ( $O_2$ ) through the input of electric energy as  $2H_2O \rightarrow 2H_2 + O_2$ . This requires water, electricity, and (depending on the technology) heat as inputs. As the processes of alkaline and proton exchange membrane electrolysis do not need thermal input energy, and are the two most developed technologies, no heat requirements are assumed here [51]. Additionally, while the resulting oxygen is not further investigated in this analysis, it could potentially be captured and serve as an additional revenue stream.

The levelized cost of hydrogen ( $LCOH$ ) representing the total specific hydrogen production cost is calculated as:

$$LCOH = \frac{\frac{CAPEX + c_{stack}}{PVF} + OPEX}{FLH \cdot \frac{\eta_{ely}}{w_{H_2}}} + LCOE \cdot \left( \frac{w_{H_2}}{\eta_{ely}} \right) + c_{H_2O} \cdot v_{H_2O} \quad (7)$$

where  $c_{stack}$  represents the cost of stack replacement,  $FLH$  represents the full load hours of system,  $\eta_{ely}$  represents the electrolysis system efficiency,  $w_{H_2}$  represents gravimetric energy density,  $v_{H_2O}$  represents the volume of water, and  $c_{H_2O}$  represents water costs. These water costs are calculated as:

$$c_{H_2O} = c_{H_2O_{spec}} + c_{H_2O_{transport}} + E_{H_2O} \cdot LCOE \quad (8)$$

where  $c_{H_2O_{spec}}$  represents specific water costs,  $c_{H_2O_{transport}}$  represents water transport costs, and  $E_{H_2O}$  represents water purification energy demand. For both  $LCOE$  and water costs, the cheapest value in each production location is chosen. Water can be drawn from a water body, water way, or the ocean – if the ocean is selected, desalination is taken into account.  $LCOH$  is calculated in €/kg $H_2$ .

The electrolysis system is always scaled in such a way that the minimum of 5,000 h in case of wind electricity production shall be full load hours. Therefore, the electrolysis power installation is not 1:1 to the wind power installed, but designed smaller to ensure that it runs on a base power and thus it does not have to deal with the instability of the renewable energy sources.

## 2.3. Conversion

Converting hydrogen to other forms can increase its volumetric energy content or alter its storage conditions and therefore allow a more economical distribution process. In the developed model, conversion is allowed both before and after transportation, as transporting hydrogen in a different state than needed at the demand point can unlock possible economically advantageous transport methods. The conversion processes modelled here are compression to 500 bar, liquefaction, and the transformation of hydrogen to ammonia ( $NH_3$ ) and liquid organic hydrogen carriers (LOHC). Throughout this work, we consider the LOHC carrier benzyltoluene.

Hydrogen after electrolysis is assumed to be a pressure of 25 bar and a temperature of 298.15 K. The costs to convert hydrogen to other forms are then calculated as:

$$c_{conversion} = \frac{CAPEX}{PVF} + OPEX + c_{heat} \cdot E_{heat} + LCOE \cdot E_{elec} \quad (9)$$

where  $c_{heat}$  represents specific heat costs,  $E_{heat}$  represents thermal energy demand, and  $E_{elec}$  represents electricity demand. Losses of hydrogen due to leakage or boil-off are neglected. Heat which is released during conversion processes is assumed to not be monetized and released without further processing.

## 2.4. Transport

Two hydrogen transport options are considered: road transport via trucks with trailers; and a pipeline system. All combinations of hydrogen state and type of transport between supply and demand are calculated and the most favourable economic option for distribution is selected. This, for example, means that transport of ammonia is permitted even if the demand scenario is for pure hydrogen. In this example, costs would be incurred again at the demand centre for the re-conversion back to pure hydrogen; these costs are integrated in the optimization.

Road transport is modelled with the four hydrogen states previously discussed: 500 bar, liquefied  $H_2$ , LOHC, and  $NH_3$ . Road transport costs are calculated as:

$$c_{transport_{road}} = \frac{CAPEX_{vehicle}}{PVF_{vehicle}} + OPEX_{vehicle} + c_{fuel} + c_{wages} \quad (10)$$

where  $vehicle \in \{Trucks, Trailers\}$ ,  $c_{fuel}$  represents the cost of fuel, and  $c_{wages}$  represents the cost of wages.

Gaseous hydrogen can be transported via pipeline. The transformation into the desired state is in this case always modelled at the demand site. Pipelines are divided into three subcategories: small (maximum



capacity 1.2 GW), medium (maximum capacity 4.7 GW), and large systems (maximum capacity 13 GW). For the sake of simplicity, the same distance is chosen for the pipeline between a production and demand location as the road distance between the two. Furthermore, only the construction of new pipelines is considered. While retrofitting existing pipelines could potentially be more economical, due to uncertainties regarding their condition, the connected networks, and the state of existing compressors, this option is not further investigated. Pipeline transport costs are calculated as:

$$c_{transport\ pipeline} = \frac{CAPEX_{equip}}{PV_{equip}} + OPEX_{equip} + c_{electricity} \quad (11)$$

where  $equip \in \{Pipeline, Compressor\}$  and  $c_{electricity}$  represents electricity costs.

## 2.5. Storage

To be able to guarantee security of supply, a three-day storage facility is modelled by default. The storage at the production site is selected to match the calculated least-cost transport technology. At the demand centre, the storage is designed to accommodate the required hydrogen state. If a pipeline is built, no storage is built on the production side, as the pipeline itself can serve as storage. Storage costs are calculated as:

$$c_{storage} = \frac{CAPEX_{storage}}{NPV_{storage}} \quad (12)$$

where  $NPV_{storage}$  represents the net present value of the storage system.

## 2.6. Road and electricity infrastructure

This method allows the possibility to “construct” new road or electricity infrastructure and to see how this impacts hydrogen costs. New electricity transmission lines can be modelled to connect production locations to the existing network, potentially lowering  $LCOE_{grid}$ . They can also be modelled to connect production locations close to demand centres to the grid, making it possible to use cheaper electricity for hydrogen production in geographically advantageous locations. New roads can be modelled to allow road transport for locations which are currently unreachable by road, where only transport via pipeline systems would be possible at present.

The existence of a network (both road and grid) is represented with a distance variable. If the corresponding network is running through a hexagon, the distance variable is equal to 0. If however does not run through a specific hexagon, the shortest distance between the central point of this hexagon and the network is calculated. Based on this distance the total construction costs are approximated. Infrastructure costs are calculated as:

$$c_{infra} = \frac{CAPEX_{infra} + OPEX_{infra}}{NPV_{infra}} \quad (13)$$

where  $OPEX_{infra}$  is only modelled for road infrastructure and not for electricity infrastructure.

## 2.7. Geospatial modelling

As previously discussed, the defined relationships are applied spatially across localized demand and supply centres. H3 hexagons [41] are used as areas of analysis. These are distributed evenly across the region of interest. Using H3 hexagons allows analysis at multiple resolutions without requiring major model modifications. As hexagon tiles regularly fill space optimally, and are equidistant from their neighbours, modelling is simplified significantly compared to the use of a square or otherwise shaped grid [42]. Each hexagon is assigned spatial and socioeconomic input data which underlie all previously described modelling. Following execution, results are assigned to each hexagon and can be displayed and evaluated. Here, H3 Hexagons with

**Table 1**

Input data assigned to each geospatial hexagon, what the purpose of this specific data is, and which geographical data set was used for it.

Input	Purpose	Source
PV potential	Determine electricity output of PV modules.	Global Solar Atlas [48]
Wind speed	Determine electricity output of standardized wind turbine.	Global Wind Atlas [49]
National grid	Calculate closest distance to grid to determine electricity transmission possibility and/or grid construction costs.	OpenStreetMap [52]
Road network	Calculate closest distance to road network to determine road availability and road construction costs.	OpenStreetMap [52]
Water supply	Calculate closest distance to water bodies, ways and the ocean to determine water costs.	OpenStreetMap [52]
Quantity of constructable power plants	Estimation of theoretical achievable power and hydrogen production capacity.	“Geospatial Land Availability for Energy Systems” model [53].

a set resolution of 5 are used. Each hexagon represents an average area of 252.9 km<sup>2</sup>. This resolution allows for a good initial assessment of regional potentials and provides a low computational time. If a coarser or finer resolution is desired, this can be changed when creating the geographic input file and applied to the model without further adjustments. Table 1 illustrates which input data are assigned to each hexagon, what the purpose of this specific data is, and which data source is used.

## 3. Results

The spatial hydrogen cost modelling method described above is applied in Kenya as an illustrative case study. Results are first presented for  $LCOH$  across the whole country (i.e., without considering conversion to any other hydrogen state or transport costs). Then, results are presented for three example demand cases: ammonia production for fertilizer, freight transport, and export to Europe from Mombasa. Any data inputs which are not already captured in Table 1 for these applications are outlined either in the sections below or in the Supplementary Material.

### 3.1. $LCOH$ across Kenya

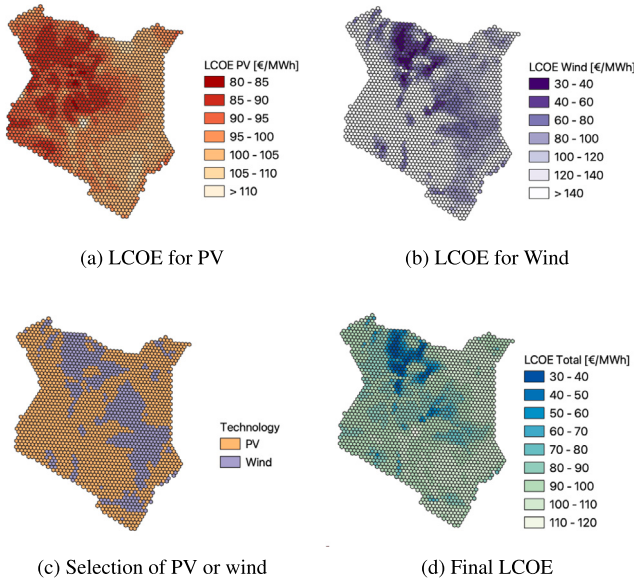
$LCOH$  is calculated across Kenya. First,  $LCOE$  is determined in each hexagon, as shown in Fig. 2. PV electricity production costs show minimal spatial variation; the production costs of wind show more spatial variation. The  $LCOE$  from PV ranges between €80–120/MWh. Electricity production from wind makes the most sense in northern areas, where average wind speeds of up to 15 m/s are reached and  $LCOE$  is around €30/MWh.

The  $LCOH$  is then calculated for each hexagon using the  $LCOE$  results. The full load hours of electrolysis are taken to be 3,000 h if powered via PV and 5,000 h if powered via wind based on annual duration curves and capacity factors generated for Kenya; for a full justification, please refer to the heading “Hydrogen production capacity” in the Supplementary Materials. Results, shown in Table 2 and Fig. 3, indicate that hydrogen production costs largely follow the pattern of the  $LCOE$ . In northern areas where wind energy can achieve low  $LCOE$ ,  $LCOH$  less than €4.0/kg can be achieved. Most areas, however, have  $LCOH$  of €6.0–8.0/kg and are primarily powered by solar PV.

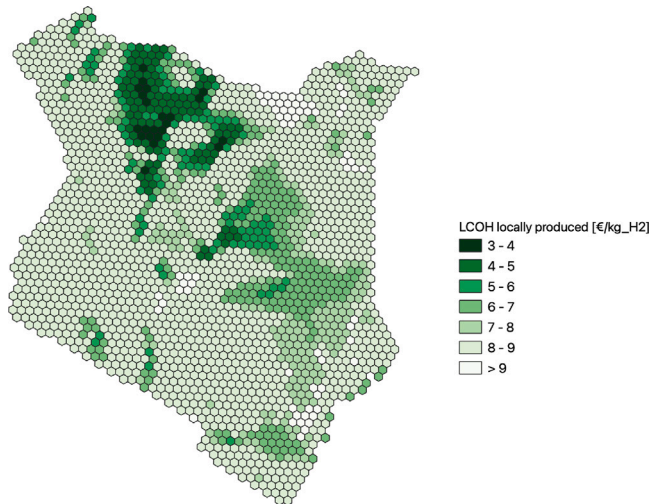
The reason for the large range of  $LCOH$  and its close linkage with  $LCOE$  is the high electricity demand of the electrolysis system

**Table 2**  
Statistical summary of the levelized cost of hydrogen in the base case.

Result	Base case value (€/kg <sub>H<sub>2</sub></sub> )
Minimum LCOH	3.655
Maximum LCOH	9.912
Median LCOH	8.351
Mean LCOH	7.893

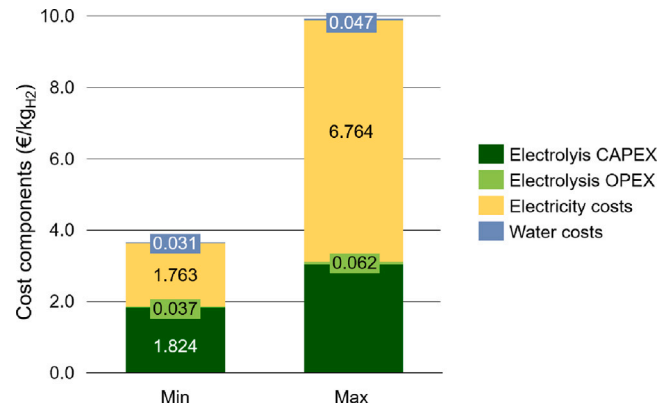


**Fig. 2.** Achievable levelized cost of electricity (LCOE) in Kenya based on analysis of wind and solar photovoltaic technologies.



**Fig. 3.** Resulting levelized costs of hydrogen (LCOH) for hydrogen produced locally in each hexagon.

considered. Considering an electrolysis system efficiency of 59% as per [51] (taking the lower heating value of hydrogen) the electricity input amounts to approximately 56.5 kWh/kg<sub>H<sub>2</sub></sub>. This is also highlighted in Fig. 4, which illustrates the cost components of the LCOH for the hexagons with the lowest and highest LCOH values. While the electrolysis costs vary with the full load hours (i.e., 3,000 for areas using PV generation and 5,000 for areas using wind generation), the main cost gap can be traced back to the electricity costs. While in the cheapest location these amount to €1.76/kg<sub>H<sub>2</sub></sub> or 48% of total costs,



**Fig. 4.** Cost components of minimum and maximum identified levelized cost of hydrogen.

**Table 3**  
Median and mean levelized cost of hydrogen with transmission cost variation.

Transmission cost (€/MWh)	Median LCOH (€/kg <sub>H<sub>2</sub></sub> )	Mean LCOH (€/kg <sub>H<sub>2</sub></sub> )
10	8.218	7.442
20	8.218	7.511
30	8.218	7.580
40	8.218	7.648
50	8.218	7.716
60	8.218	7.822

they make up €6.76/kg<sub>H<sub>2</sub></sub> or 69% of total costs at the most expensive location. Both water costs and the OPEX of the electrolysis system do not have a significant impact on the total LCOH, even though the water costs include purchase, energy costs for purification, and the transport to the production site.

Hexagons connected to the grid are allowed to purchase electricity from other connected hexagons, incurring transmission costs. Fig. 5 shows LCOH accounting for grid connection, with transmission costs of €30/MWh. The grid exchange can be clearly seen here: the hexagons connected to the grid receive the most favourable LCOE that exists across the network, and thus they also have the same LCOH. The transmission cost parameter is varied in the range €10–60/MWh, producing the results shown in Table 3. While all of these scenarios show the same minimum and maximum LCOH as the base case, the median and mean values are slightly below the base case. Although no significant cost reductions can be achieved in all regions, it is possible to achieve lower LCOH in regions that are connected to the grid (compare Fig. 3 with Fig. 5). As these regions are usually also economic centres, and therefore also potential bulk hydrogen consumers, this can reduce the total costs of hydrogen, as distribution is often less costly with shorter transport distances.

The construction of new transmission lines is also considered. Here, the grid is considered exclusively for the transport of electricity for hydrogen production, and thus the entire costs for this are also taken into account and offset against the LCOH. The results indicate that it is favourable to few hexagons construct new transmission lines, and to do so brings only a small cost advantage. We find that hydrogen production costs along the connected grid can be reduced by a further €0.34/kg by the construction of new lines. This cost reduction is achieved despite the high CAPEX of the transmission line and the unrealistic consideration that it is used exclusively to enable hydrogen production and not for electrification, integration of new electricity sources, stabilization and efficiency increase.

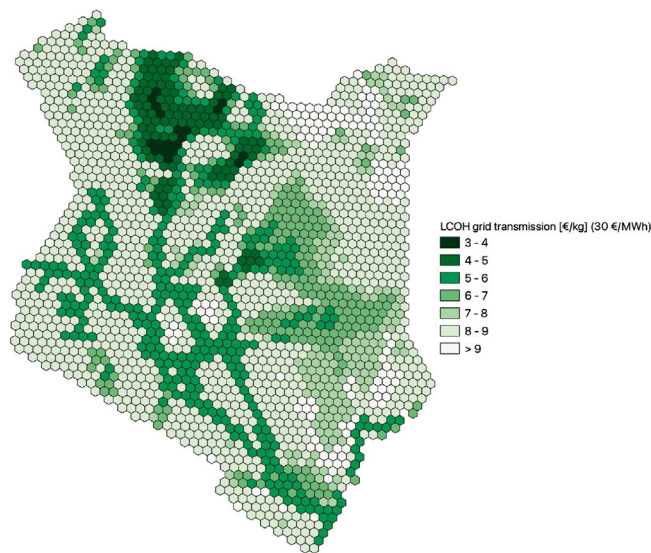


Fig. 5. Levelized cost of hydrogen (LCOH) possible considering production in each hexagon with inclusion of transmission lines and transmission costs of 30 €/MWh.

### 3.2. Evaluation of specific hydrogen demand application

Three potential use cases for hydrogen production in Kenya are modelled: ammonia, freight transport, and export. These illustrate how the developed model can be used to spatially couple supply and demand.

#### 3.2.1. Ammonia

Hydrogen is a feedstock for ammonia, which is a key input for several fertilizers. Most fertilizer used in Kenya is imported [54]; domestic production of green ammonia for fertilizer could therefore save emissions, create new revenue streams, foster economic development, and decrease international dependency.

In 2020, approximately 650 kt of ammonia-based fertilizers were imported to Kenya [54]. Almost half of this is diammonium phosphate (DAP), which has an input of  $0.2 \text{ t}_{\text{NH}_3} / \text{t}_{\text{DAP}}$  [55]. 23% is urea;  $0.57 \text{ t}_{\text{NH}_3}$  of ammonia are needed to produce  $1 \text{ t}_{\text{urea}}$  fertilizer. 20% is nitrogen-phosphorus-potassium-fertilizers (NPK). It is difficult to confirm the ammonia input required in NPK, as the nitrogen share in these can vary significantly and affects the amount of ammonia required. As an assumption, 25% of ammonia input is considered (i.e.,  $0.25 \text{ t}_{\text{NH}_3} / \text{t}_{\text{NPK}}$ ). Lastly, ammonia sulfate consists of approximately  $0.256 \text{ t}_{\text{NH}_3} / \text{t}_{\text{fertilizer}}$  and is, with 3%, the smallest considered fertilizer share [56].

In total, the ammonia required to produce these fertilizers is approximately 195 kt/a. Hydrogen accounts for 17.8% of the mass of ammonia, meaning that the amount of hydrogen required would therefore be approximately 35 kt/a. While this can be expected to grow in the coming years based on population growth and increasing threats to agricultural activities from climate change, which can be in part remediated through inputs like fertilizer [57], the present estimated value is used here. The demand for this use case is modelled in Nairobi, given its status as Kenya's main economic hub.

Fig. 6 shows the 100 cheapest ammonia production locations (a) and most cost-effective production locations (b) to cover this demand. Wind-intensive sites in the country's north have an especially low ammonium production cost of €0.87–0.88/kg<sub>NH<sub>3</sub></sub>. The most favourable site has a theoretical hydrogen production capacity of more than 80 kt/a and can therefore supply the total demand of ammonia.

A breakdown of the total ammonia costs for the minimum cost production location is shown in Fig. 7. In the cheapest production location (shown in dark green in 6a), electricity is produced with wind and transportation is via NH<sub>3</sub> trailers.

#### 3.2.2. Freight transport

Hydrogen fuel cell (FC) trucks could be used along Kenya's northern corridor for freight transport. This would require a HRS network, as modelled in this use case. The northern corridor is an important trade route in Kenya, connecting the port of Mombasa with Kenyan and East African economic hubs.

In 2017, there were 13,070 HGV in Kenya's national fleet, each with an average annual millage of 63,205 km [58]. This demand case assumes that 50% of the heavy good vehicles (HGV) in Kenya are utilized along this route, as the route goes through regions which cover approximately 50% of Kenya's GDP [59]. We therefore model that 50% of HGVs could therefore be substituted by FC trucks. This fleet segment would drive approximately 413 million km per year. We model that an average of 9 kg<sub>H<sub>2</sub></sub>/100 km is consumed based on a typical average consumption of 8 kg/100 km [60] and an additional 1 kg/100 km to account for poor road conditions. This therefore represents a total hydrogen demand of 37.2 kt [61,62]. This H<sub>2</sub> would need to be spread across HRS along the northern corridor, spanning from Mombasa to Busia. Large filling stations typically have a maximum capacity of 3,000–5,000 kg/day [63,64]; 3,000 kg/day stations are assumed here. If an equally distributed HRS network of 3,000 kg/day facilities is built on the 973 km section of the northern corridor within Kenya, at least 34 HRS would have to be constructed to meet freight demand. This corresponds to one filling station every 30 km. It is assumed that hydrogen demand is evenly distributed among the 34 filling stations. Assuming a capacity utilization of about 75%, extra costs of about €1.65/kg are included in the hydrogen price due to the CAPEX and OPEX of the filling stations [64]. In most cases, stations store the hydrogen pressurized at 500 bar temporarily before it is dispensed, and therefore no storage costs are included in the hydrogen distribution. This demand case is modelled in two ways:

1. by considering each filling station as a separate project, with a unique demand and independent production and distribution; and
2. by considering the whole set of filling stations as a unified project, with a unified demand and optimized production and distribution across all stations.

The distance to the individual demand locations is approximated with the mean distance value across all HRS in the second (i.e., unified project) case.

In both cases, the resulting least-cost production locations are in the northern, windy part of Kenya (see Fig. 8). In the first analysis, three hexagons are selected for production directly next to each other. In the second analysis, only one hexagon is selected for production, due to the sufficient production capacity available in the most favourable hexagon to meet the unified demand.

While the least-cost production selected sites do not vary significantly based on whether the filling stations are considered as separate or unified demands, the overall costs of the supply chain of hydrogen do. The total costs in the case of each filling station as a separate project varies between €5.4–6.3/kg<sub>H<sub>2</sub></sub> with an average value of €5.8/kg<sub>H<sub>2</sub></sub> and thus annual costs to meet the full hydrogen requirements total €214.45 million. Conversely, when considering the fuelling stations as one project with a unified demand, LCOH of €4.7/kg is achievable, resulting in total costs of €173.93 million. A significant cost saving – €40.52 million – can therefore be achieved through holistic planning, due to economies of scale in the conversion and distribution process.

This is highlighted in Fig. 9, which compares the cost breakdown of an average production site when HRS are considered as separate and unified projects. Due to the linearity of investment costs assumed for RES and electrolysis systems, the costs for hydrogen production are the same. However, better utilization and possible specific cost reductions of the conversion and distribution technologies bring the total costs of production significantly lower when the stations are considered as a unified project.



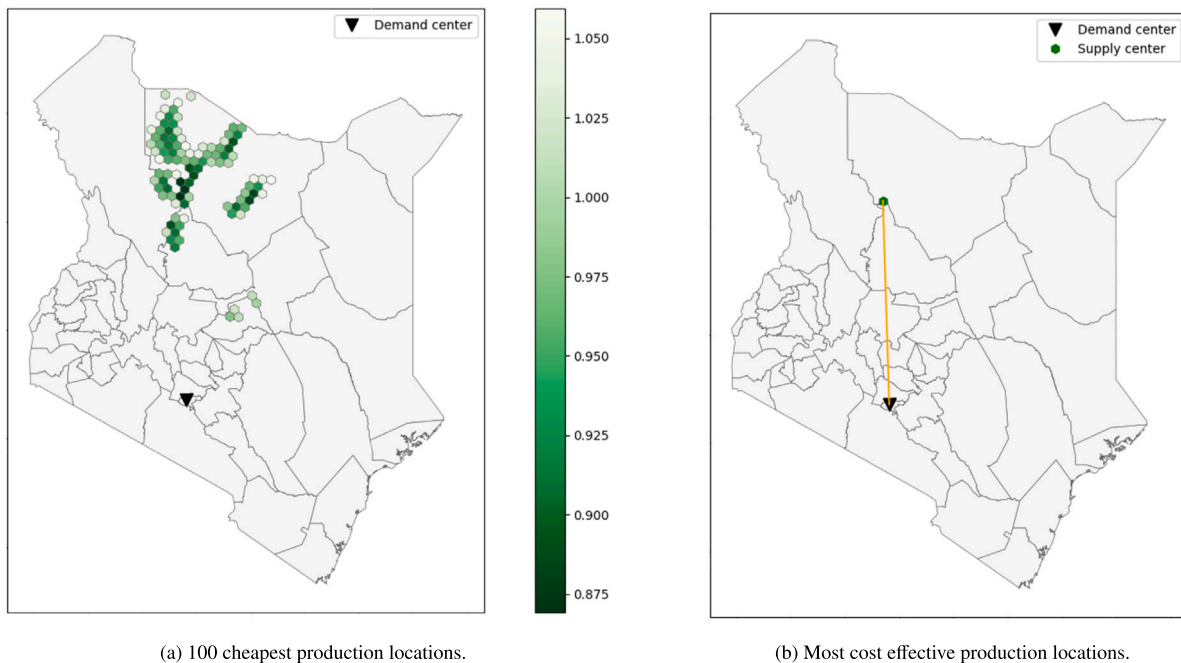


Fig. 6. Cheapest production sites in the ammonia use case, considering the demand being centred in Nairobi (€/kg<sub>NH3</sub>).

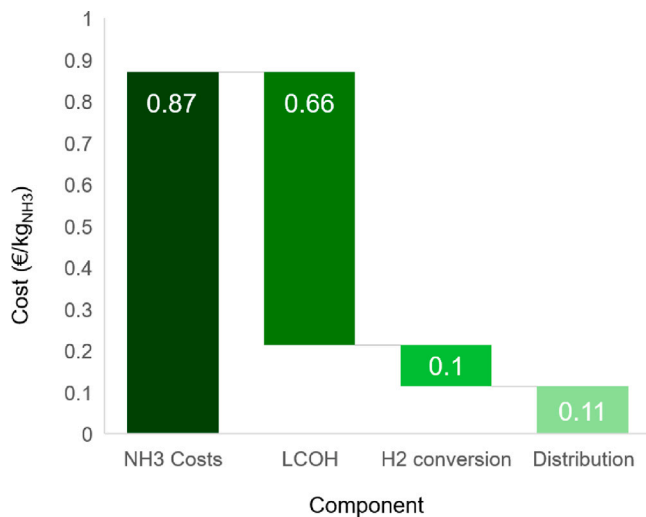


Fig. 7. Breakdown of ammonia costs in the ammonia use case.

### 3.2.3. Export

Export is a mid- to long-term goal for green hydrogen in Kenya. This use case looks at exporting three liquid carrier states of hydrogen; liquefied H<sub>2</sub>, LOHC, and ammonia. It considers exporting 100 kt/a from the port of Mombasa to Rotterdam. The costs of hydrogen export can be divided into three subcategories: (1) production and distribution in the exporting country; (2) shipping and associated processes; and (3) carrier handling, transformation, and distribution in the importing country.

Table 4 illustrates the total costs of hydrogen production and transportation to the port of Mombasa, depending on the chosen hydrogen shipping state and the annual export quantity. For all hydrogen states, production and distribution become cheaper with increasing quantity. In the case of liquefied H<sub>2</sub> in particular, there is a large cost gap due to the high specific investment costs of the liquefaction plant at low flow rates. LOHC and ammonia offer similar costs and can undercut €5.0/kg

Table 4

Total costs of hydrogen production and transport to Mombasa depending on the hydrogen shipping state and the annual export quantity.

Hydrogen shipping state	Export quantity (kt/year)			
	1	10	100	1,000
Liquefied Hydrogen	10.86	6.10	5.58	5.23
Ammonia	6.25	5.48	5.43	4.70
LOHC	5.49	5.2	5.16	4.19

at high quantities. Based on these results, LOHC is the cheapest option at any quantity. As in the previous demand cases, the most favourable production sites are located in the northern, windy areas in Kenya.

The shipping route from Mombasa to Rotterdam is approximately 13,200 km long. It runs through the Arabian sea, along the Suez Canal, through the Mediterranean Sea, and finally through the Strait of Gibraltar up to the North Sea [65]. Costs incurred for shipping are based on Johnston et al. [66], where a similar distance was considered. In this study, several routes were investigated, including between Valparaíso to Rotterdam with a distance of approximately 13,800 km. The cost of shipping liquefied hydrogen along this route was calculated at €1.38/kg<sub>H<sub>2</sub></sub>, LOHC at €0.96/kg<sub>H<sub>2</sub></sub> and ammonia at €0.39/kg<sub>H<sub>2</sub></sub>; these figures are used here.

Depending on the distribution method at the import location, ammonium and LOHC may have to be converted back into pure hydrogen upon import. Assuming electricity costs of €0.25/kWh based on the average at time of modelling [67] and heat costs of €0.06/kWh, these processes (without considering possible purification) cost approximately €1.17/kg for ammonia and €1.14/kg for LOHC.

The total costs of hydrogen at the import site are shown in Fig. 10. Regardless of the transport state chosen, the cost of pure hydrogen at the Port of Rotterdam is around €7/kg.

## 4. Discussion

This work finds *LCOH* of €3.7–9.9/kg<sub>H<sub>2</sub></sub> across Kenya, depending on the location chosen, with more than 50% of theoretical capacity lying below €5/kg<sub>H<sub>2</sub></sub>. Green hydrogen produced in



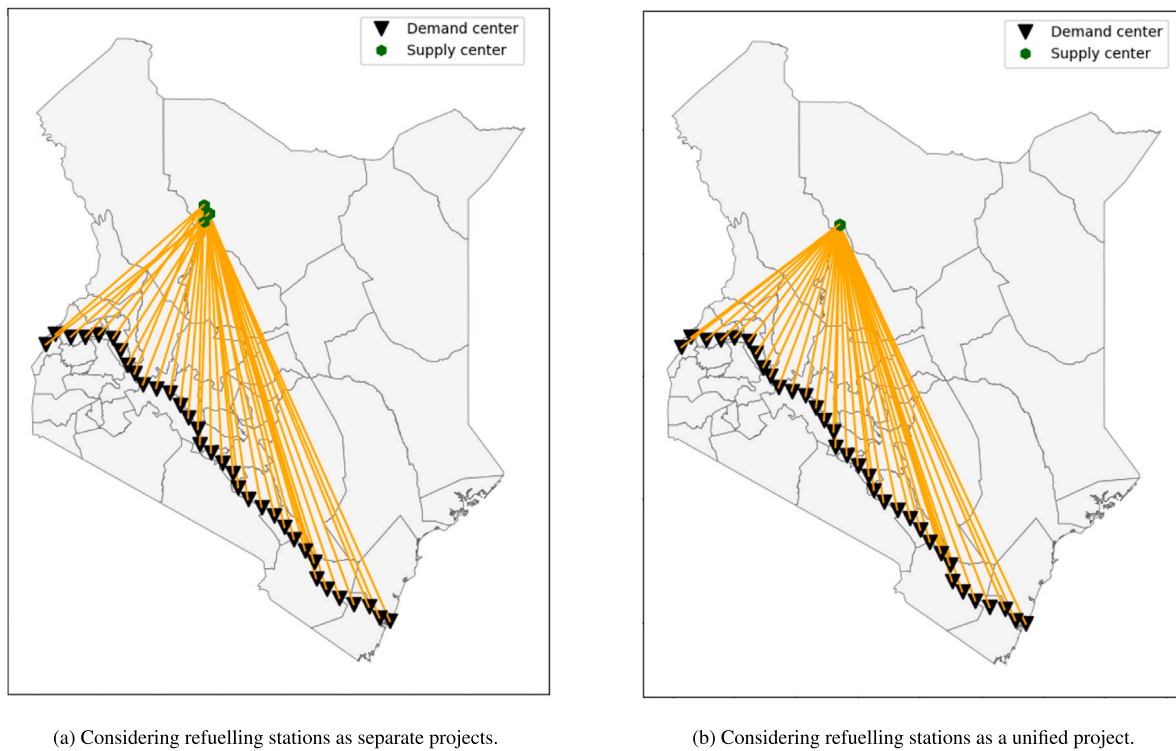


Fig. 8. Selection of production locations in the freight demand case.

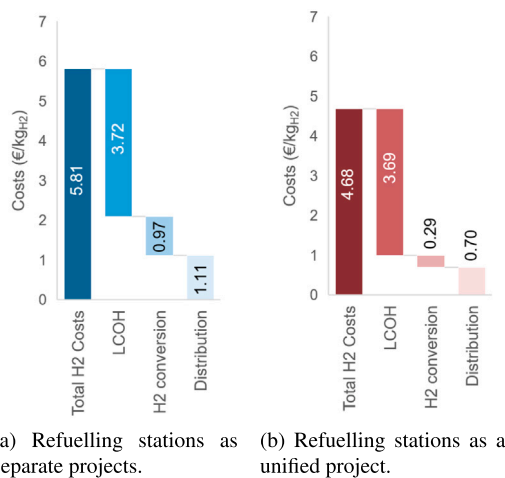


Fig. 9. Hydrogen cost breakdown to demand centre for the two freight shipping analyses.

Kenya therefore appears to be competitive with international prices, especially given current high electricity and gas prices due to the Russian-war-induced fuel shortage.

While the lowest-cost hydrogen production locations depend on the use case considered, they tend to follow the same pattern as the lowest *LCOE*. This is particularly evident for higher hydrogen quantities, as specific costs for conversion and transportation decrease. The cheapest production locations in Kenya are therefore in the northern areas, to the south-east and south of Lake Turkana, where constant high wind speeds result in low *LCOE*, indicated both by the overall *LCOH* results across Kenya and in each of the demand cases modelled.

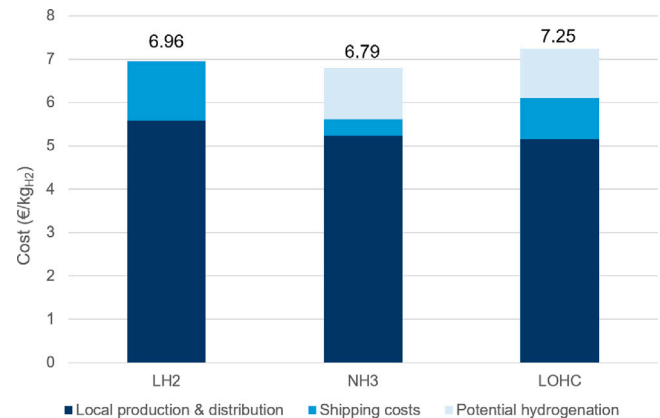


Fig. 10. Total hydrogen costs for Mombasa–Rotterdam export demand case.

#### 4.1. Ammonia

The results of the first demand case indicate that **Kenyan ammonia would be cost competitive in the current energy crisis, and can remain competitive long-term if carbon pricing is introduced across the energy sector**. Historically, the global market price of anhydrous ammonia has largely fallen between €100–400/t [68]. However, as ammonia is currently largely produced via the steam reforming process (also known as blue hydrogen), production costs and thus also sales prices are highly dependent on gas prices. Due to the substantial increase in gas prices and the sanctions imposed on Russia (i.e., the world's second-largest ammonia producer), purchase prices have risen to up to €1,500/t [69]. As such, the ammonia costs at the

**Table 5**

Conventional ammonia production costs and break-even levelized costs of hydrogen with varying carbon prices. Conventional ammonia costs based on [70].

Carbon price (€/t <sub>CO2</sub> )	Conventional NH <sub>3</sub> cost (€/kg <sub>NH3</sub> )	Break-even LCOH (€/kg <sub>H2</sub> )
0	0.40	1.05
50	0.48	1.52
100	0.57	1.98
150	0.65	2.44
200	0.73	2.91

demand centre found here, at €870/t including production, conversion, and distribution, show that NH<sub>3</sub> produced in Kenya can already be cost-competitive in the current energy crisis.

It cannot be assumed, however, that ammonia costs will remain this high. For non-crisis situations, ammonia production costs using conventional methods are estimated at €400/t in 2030 [70]. In the long term, the cost competitiveness of Kenyan ammonia therefore depends on carbon pricing. If no carbon price is introduced (i.e., a carbon price of €0), Kenyan NH<sub>3</sub> is likely to be significantly more expensive than the market price. However, if a carbon price is introduced, this changes.

Table 5 shows the projected costs of ammonia using conventional processes (i.e., using natural gas) and varying carbon emission prices for the year 2030. The required LCOH in Kenya is calculated from this, assuming that both conversion and distribution costs remain the same over time. If a CO<sub>2</sub>-price of €100/t is introduced, Kenyan ammonia produced with an LCOH of around €2.0/kg<sub>H<sub>2</sub></sub> will be cost competitive, and with CO<sub>2</sub>-prices of €200/t, even ammonia produced with an LCOH close to €3.0/kg<sub>H<sub>2</sub></sub> will be competitive. While this is still lower than the lowest achievable LCOH we find in Kenya at the moment, it is likely that LCOH will decrease below this by 2030, as will be discussed in Section 4.4. As such, with a carbon price and anticipated LCOH reductions, Kenyan ammonia could be competitive on the world stage within the next decade.

#### 4.2. Freight transport

The results of the second demand case show that **hydrogen-based freight transport is a less promising application in Kenya**. It is difficult for hydrogen-based freight to be cost competitive, particularly due to high vehicle and infrastructure CAPEX compared to the conventional alternative, diesel trucks.

Fuel costs for hydrogen FC trucks are higher than for the diesel fuelled alternative. This analysis assumed 9.0 kg<sub>H<sub>2</sub></sub>/100 km is consumed by FC HGVs, while equivalent diesel trucks consume about 36.0 L/100 km [62]. We find average hydrogen costs of €5.8/kg<sub>H<sub>2</sub></sub>, resulting in a fuel cost of €52.2/100 km. Meanwhile, diesel costs €1.1/L in Kenya [71], resulting in a total fuel cost of €39.6/100 km.

While the difference in fuel costs for hydrogen FC and diesel trucks is not so dramatic, the difference in CAPEX is, and is decisive in the economics of operation. The CAPEX of current FC trucks lies around €550,000–600,000, while diesel trucks can be purchased for €100,000–150,000 [62]. Assuming a maximum annual driving distance of 160,000 km/a and a life duration of 8 years, additional costs for FC trucks compared to diesel trucks amount to approximately €35/100 km due to the higher CAPEX.

The hydrogen price at the refuelling station required for competitive operation, including the additional costs due to the CAPEX, is shown in Table 6. FC trucks therefore cannot compete with diesel trucks at present. Cost-competitive operation of hydrogen freight could be achieved either by a significant increase in diesel prices, a reduction in the cost of hydrogen at the refuelling station, and/or a significant reduction in the investment costs of FC trucks. CAPEX reduction could also be achieved through, among other things, government subsidies to drive a technology push. However, as other technologies (e.g., battery

electric trucks, electric or FC trains) can also offer zero emission freight transport, a feasibility study which takes all freight technologies into account should be made before one is selected for subsidy.

#### 4.3. Export

The results of the export case indicate the potential of **Kenya exporting green hydrogen to Rotterdam with total unit costs of €7.0/kg<sub>H<sub>2</sub></sub> regardless of which carrier medium (liquefied H<sub>2</sub>, LOHC, or NH<sub>3</sub>) is used, undercutting current market prices**. To realize this potential, Kenya would have to address two key points: namely, to (1) conceive of approaches to capitalize on synergies between domestic and foreign usage of green hydrogen, and (2) to build the required soft and hard infrastructure. Using international and private investments to establish a local industry, for instance through local content requirements like in South Africa's renewable energy sector [72], can catalyze the domestic industry if adequate distributive mechanisms are implemented. Kenya is likely to have to move comparably quickly on this issue given the rapid establishment of strategic green hydrogen partnerships [7] and comparably high shipment costs due to its distance from future demand hubs (e.g., Europe, Japan, South Korea).

Second, in order to realize its potential for export, Kenya would have to ensure that both the required infrastructure for green hydrogen compression and shipment is built, and, critically, start to build domestic skills in green hydrogen and its adjacent supplier industries [73]. With such a domestic skills offensive, technology transfer is unlikely to occur and domestication of green hydrogen benefits will be exacerbated [8]. International cooperation through public finance, concessional loans and skills transfer can help to de-risk investment in infrastructure, and help establish and scale the required engineering and social science education programmes in Kenya.

#### 4.4. Outlook for 2030

Renewable energy technologies are catching up with fossil fuels in terms of costs through technology development, economies of scale, reduction in initial investment costs, and performance improvement [3]. Similar techno-economical improvements are also expected for hydrogen technologies [51].

The RES generation technologies considered for hydrogen production in this study (i.e., wind and solar PV) experienced significant price drops in the last few decades. Between 2010–2021, the total installed costs for onshore wind projects dropped on average by 4% annually, and solar PV achieved a total installed cost reduction of 14% per year [3]. If PV and onshore wind projects in Kenya follow the same trend in upcoming years, CAPEX for wind projects could land at around €1,100/kW in 2030, and those of PV around €377/kWp.

Major improvements are also expected in terms of electrolysis system efficiency and investment costs. IRENA expects the CAPEX of these electrolysis technologies to be below €200–300/kW by 2050. Furthermore, increased output pressures are expected, which will reduce the required energy input for compression and increase system efficiency to 74% and higher [51]. Other studies come to similar results – for instance, a cost range of €444–730/kW, depending on chosen technology (proton exchange membrane and alkaline) and plant size (minimum 5 MW, maximum 100 MW) is forecast in 2030, with system efficiencies of up to 70% [74]. Therefore, a CAPEX of €600/kW can be realistically predicted. This translates to a halving of costs by 2030. This 50% decrease is also applied to the stack exchange costs.

If these techno-economic improvements can be achieved (i.e., 50% cost reduction and 74% efficiency), hydrogen production costs across Kenya could drop to €1.8–3.0/kg<sub>H<sub>2</sub></sub> by 2030. Most production locations would choose PV as a generation technology; however, the cheapest production locations still use wind power for electricity generation.

Table 6

Competitive hydrogen price for freight shipping with varying values of carbon and diesel prices, including CAPEX.

Carbon price (€/t <sub>CO2</sub> )	Diesel price (€/L)										
	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0
0	-1.56	-1.16	-0.76	-0.36	0.04	0.44	0.84	1.24	1.64	2.04	2.44
50	-1.03	-0.63	-0.23	0.17	0.57	0.97	1.37	1.77	2.17	2.57	2.97
100	-0.50	-0.10	0.30	0.70	1.10	1.50	1.90	2.30	2.70	3.10	3.50
150	0.03	0.43	0.83	1.23	1.63	2.03	2.43	2.83	3.23	3.63	4.03
200	0.56	0.96	1.36	1.76	2.16	2.56	2.96	3.36	3.76	4.16	4.56

#### 4.5. Future work

The model developed in this paper could be improved through further work. While data quality regarding geospatial and investment parameters has markedly improved in the last few years in Kenya and Africa as a whole [7,12,47], there is still considerable uncertainty in several cost parameters, such as transport of green hydrogen at scale and both technology and finance cost developments in the future. Stochastic approaches and further sensitivity analyses might be interesting approaches to account for this data uncertainty. Furthermore, the current model implementation only allows one RES generation technology to be selected for use in hydrogen production in each geospatial hexagon (i.e., PV or wind). This selection is presently made on the basis of the *LCOE*, and the joint construction of wind and PV technology is not permitted. Research regarding the combination of wind and solar plants for the production of hydrogen suggests that this can lead to lower *LCOH* overall, as the full load hours of the electrolysis plant can be increased and thus the specific CAPEX per kg hydrogen can be decreased [75]. Allowing for an optimized combination of PV and wind in each geospatial H3 hexagon would improve the cost accuracy in future work. Given the current model formulation, the cost estimates made here are therefore conservative; it may be possible to lower them with improved design of the generation sources used for green hydrogen production which incorporate a combination of PV and wind in each cell.

#### 5. Conclusion

This paper has investigated the least-cost location of green hydrogen production for varying use cases while balancing demand and supply. To this end, a novel spatial hydrogen cost modelling method (available on GitHub: <https://github.com/leandermue/GEOH2>) has been developed to allow the assessment of green hydrogen along the entire supply chain in LMICs. This method was applied to Kenya as a case study, and it was used to investigate three possible hydrogen production use cases: ammonia production for fertilizer, hydrogen-based freight transport, and hydrogen export from Mombasa to Rotterdam.

Results show hydrogen production costs across Kenya of €3.7–9.9/kg<sub>H<sub>2</sub></sub> are currently achievable. Green hydrogen produced in Kenya could therefore compete with international price ranges, especially given current high electricity and gas prices due to the fuel shortage resulting from the Russian war. Least-cost locations to produce hydrogen tend to follow the pattern of the *LCOE*, especially when considering higher hydrogen quantities, as specific costs for conversion and transportation decrease. The cheapest production locations are identified in northern areas to the south and south-east of Lake Turkana, where constant high wind speeds create low *LCOE*.

We find that ammonia produced in Kenya could presently be cost-competitive given inflated energy prices due to the Russian war. Furthermore, with future technology improvements, cost reductions, and potential carbon pricing interventions, Kenyan ammonia can remain internationally competitive. Hydrogen-based freight road transport is less likely to be competitive, particularly given the high CAPEX of fuel cell trucks. Finally, for hydrogen export, we find that Kenya could export green hydrogen to a port in Europe (in this analysis Rotterdam) with total costs amounting to €7.0/kg<sub>H<sub>2</sub></sub>, undercutting

current market prices regardless of which carrier medium (liquefied H<sub>2</sub>, LOHC, or NH<sub>3</sub>) is used. Accounting for expected techno-economic improvements in technology costs and electrolysis system efficiency, hydrogen production costs across Kenya could drop to €1.8–3.0/kg<sub>H<sub>2</sub></sub> by 2030.

#### CRedit authorship contribution statement

**Leander A. Müller:** Conceptualization, Methodology, Software, Formal analysis, Data curation, Writing – original draft, Visualization. **Alycia Leonard:** Writing – original draft, Writing – review & editing, Visualization, Project administration. **Philipp A. Trotter:** Conceptualization, Writing – review & editing, Supervision. **Stephanie Hirmer:** Conceptualization, Writing – review & editing, Supervision, Project administration.

#### Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

#### Data availability

Links to all data sources are provided in supplementary material. Code is available openly and linked in the article.

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#### Appendix A. Supplementary data

Supplementary material related to this article can be found online at <https://doi.org/10.1016/j.apenergy.2023.121219>.

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