International Journal of Energy Economics and Policy

ISSN: 2146-4553

available at http: www.econjournals.com

International Journal of Energy Economics and Policy, 2022, 12(6), 293-304.

Technoeconomic Comparison of Scenarios for the Configuration of the Renewable Hydrogen Supply Chain in Colombia

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Received: 10 August 2022 **Accepted:** 02 November 2022 **DOI:** https://doi.org/10.32479/ijeep.13576

ABSTRACT

Green hydrogen (RH2) can be used as a clean fuel and as energy vector. For this reason, it is a promising solution to the problems faced by the renewable energy (RE) industry. One determining factor for achieving its practical implementation is the correct configuration of its supply chain. This study compares different hydrogen supply chain (HSC) configurations. RH2 production will be by water electrolysis using RE in the Colombian Caribbean region, then, converted into Liquid Organic Hydrogen Carrier (LOHC), Cryogenic Liquid Hydrogen (LH2) or Compressed Hydrogen Gas (GH2), later, transported by trucks and delivered to meet the projected demand of the transportation sector. In the reference scenario, we found that the best alternative is to produce RH2 using an AEC-type electrolyser (alkaline electrolysis cells) powered by wind energy and convert it to GH2 at 350 bar for transportation and storage. Then, scenarios of demand, one-way distance and WACC were considered for projections between 2030 and 2050. The results showed that can be determined the one-way distance from which converting and transporting RH2 as LOHC is the best alternative and, also can be determined this limit for demand values, which allows us to identify the best configuration of the HSC.

Keywords: Green Hydrogen, Renewable Hydrogen, Renewable Energies, Electrolysis, LOHC
JEL Classifications: Q2, Q42

1. INTRODUCTION

Most of the primary energy worldwide is produced from fossil fuels, which are obtained from coal (27%), oil (33.1%) and natural gas (24.3%) (Ritchie and Roser, 2020). At the same time, this type of fuel contributes approximately 66% of global CO_2 emissions (Foster and Elzinga, 2020), which negatively affects the environment and contributes to global warming and other problems, such as air pollution due to transport emissions. According to the World Health Organization (WHO, 2018), fossil fuels seriously damage people's health and is the cause of approximately 7 million deaths per year worldwide. In addition, if the current level of consumption of fossil fuels is maintained, reserves for some, such as oil and natural gas, will only last for approximately 50 years (BP, 2020), which makes it necessary to transition to clean and renewable energy sources.

In Colombia, the situation is no different; currently, approximately 77% of primary energy is obtained from coal and oil (UPME, 2020), contributing to approximately 44% of the country's greenhouse gas (GHG) emissions (IDEAM, 2012). However, the national government made a commitment at COP21 to reduce its GHG emissions by 51% by 2030 (Minambiente, 2021). To achieve this goal in its National Energy Plan by 2050, different scenarios are proposed that promote energy generation from nonconventional sources to electrify the economy (UPME, 2020).

This increasing generation of energy from renewable sources, mainly from solar and wind energy systems, will lead to the challenge for domestic industries of seasonal intermittency in energy production, which is caused by the very nature of the resources used (sunlight and wind) (Dawood et al., 2020). This, in turn, creates a need for large-scale energy storage systems (Tian,

2018) (Wang et al., 2022) (Kebede et al., 2022), which are mainly aimed at matching renewable energy (RE) generation with demand (Wang et al., 2022) (Kebede et al., 2022). Another challenge of RE is that it is not feasible to electrify directly some sectors, such as heavy haulage, long-distance transport (long-haul trucks and buses, shipping and commercial aviation) and industries, such as iron and steel, cement, plastics and ammonia manufacturing (IEA, 2019). Decarbonisation of these sectors is more feasible using RE indirectly, for example, from liquid fuels based on green or renewable hydrogen (RH2), which is produced by the electrolysis of water using RE.

One of the most important factors to evaluate in producing RH2 is the type of electrolyser to be used. In the literature, three main types of electrolysers have been evaluated: alkaline electrolysis cells (AEC) (Fan et al., 2022) (Hurskainen and Ihonen, 2020) (Roos, 2021) (Karayel et al., 2021), proton exchange membrane electrolysis cells (PEM) (Fan et al., 2022) (Roos, 2021) (Karayel et al., 2021) and solid oxide electrolysis cells (SOEC) (Fan et al., 2022; Roos, 2021) (Karayel et al., 2021). Depending on the scenario, the capital cost of the electrolyser contributes 58–90% of the cost of RH2 production by electrolysis, followed by the cost of electricity (Fan et al., 2022).

Once RH2 has been obtained, the next important decision is the form in which it is to be transported and stored. Three main forms are used:

1.1. Compressed Hydrogen Gas (GH2)

GH2 is one of the most widely used forms of transporting and storing hydrogen (IEA, 2021) and consists of compressing the gas of hydrogen until it is supported by the vessel to use. In the literature, it is observed that GH2 is evaluated from 200 bar (Hurskainen and Ihonen, 2020) (Pan et al., 2021) through 350 bar (Hurskainen and Ihonen, 2020) and 500 bar (Pan et al., 2021), to handle pressures up to 700 bar, which is mainly equipped in hydrogen refuelling stations and in the internal storage tanks of vehicles equipped with fuel cells for their operation (IEA, 2021) (Bui et al., 2021).

1.2. Cryogenic Liquid Hydrogen (LH2)

LH2 is currently the second most widely used form of hydrogen transport and storage (IEA, 2021) and consists of converting hydrogen gas to liquid by modifying its pressure and temperature conditions. This process increases the volumetric energy density of hydrogen with respect to its gaseous form by reaching a pressure of only 80 bar and offers important advantages in terms of safety, economy and scale effects, especially for future large-scale applications (Pan et al., 2021). Although the boiling point of LH2 is –253°C, which generates costs to maintain low temperatures, this form of hydrogen has been evaluated as a transport and storage option in different studies (Roos, 2021) (Pan et al., 2021) (DNV GL, 2020) (Dawood et al., 2020) (Güler et al., 2021).

1.3. Liquid organic hydrogen carrier (LOHC)

A family of liquid organic chemicals or low-melting solids that can be hydrogenated (endothermic reaction) and dehydrogenated (exothermic reaction) at elevated temperatures using a catalyst and without the need to produce large amounts of carrier material for each cycle, since only approximately 0.1% degradation is generated (Figure 1). LOHCs offer advantages over GH2 and LH2 mainly in their compatibility with the existing fuel infrastructure and their ability to remain stable at ambient temperature and atmospheric pressure, which allows for long-term storage and overseas transportation under standard conditions (Aakko-Saksa et al., 2018). There are disadvantages to using LOHC compared to ammonia (NH3) or LH2, including higher fuel consumption in transporting H2 as LOHC, as more LOHC is required to transport the same amount of H2 as NH3 or LH2, and after dehydrogenation, the LOHC must be sent back for the next load of H2 (Roos, 2021). Furthermore, the conversion/reconversion processes are costly (IEA, 2021). Taking into account the advantages and disadvantages identified in different studies, LOHCs have been evaluated for transporting and storing RH2 (IEA, 2021) (Roos, 2021) (Aakko-Saksa et al., 2018) (Hurskainen and Ihonen, 2020) (DNV GL, 2020).

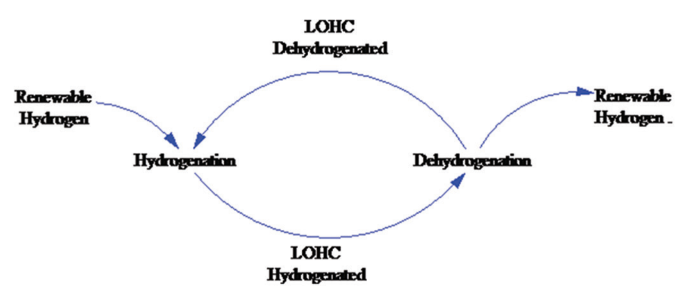
Table 1 compares three of the most commonly used LOHC options in the literature. We decided to use toluene, which, when hydrogenated, converts to Methylcyclohexane (TOL-MCH).

After deciding how RH2 will be stored and transported, the mode of transport is chosen. This will depend on the form chosen in the previous stage. GH2 and LOHCs can be transported by pipeline (Aakko-Saksa et al., 2018), whereas LOHCs can use existing infrastructure and GH2 only if blended with natural gas, since if pure GH2 is shipped, it would be necessary to replace the infrastructure (Sun et al., 2022). It is possible to transport RH2 by land in three ways: LOHC using tanker trucks, LH2 cryogenic vessels and GH2 depending on the pressure. One of the following high-pressure vessels is used (Barthélémy, 2012):

- Type I: Pressure vessel made of metal (150–300 bar)
- Type II: Pressure vessel made of a thick metallic liner hoop wrapped with a fibre-resin composite (stationary applications 150–300 bar)
- Type III: Pressure vessel made of a metallic liner fully wrapped with a fibre-resin composite
- Type IV: Pressure vessel made of polymeric liner fully wrapped with a fibre-resin composite. The port is metallic and integrated into the structure (boss).

Type III and type IV vessels are intended for portable applications at high pressures (>350 bar), for which weight savings are essential.

Figure 1: Schematic illustration of the LOHC concept.



Source: The authors

Table 1: Comparison of the main properties of the most developed LOHCs

Property		Dibenzyl toluene	N-Ethyl-Carbazole	Toluene
		Perhydrodibenzyl toluene	dodecahydro N-ethylcarbazole	Methylcyclohexane
		(DBT-H18-DBT)	(NEC-H12-NEC)	(TOL-MCH)
H2 storage capacity		6.2 wt%	5.8 wt%	6.2 wt%
Melting point/boiling point	Loaded	–39°C/390°C	69°C/378°C	–95°C/111°C
	Unloaded	–58°C/n.a	48°C/281°C	–127°C/101°C
Enthalpy of reaction		65.4 kJ/mol H2 (27% of H2 LHV)	53.2 kJ/mol H2 (22% of H2 LHV)	68.3 kJ/mol H2 (28% of H2 LHV)
Hydrogenation	Pressure	50 bar	70 bar	20–40 bar
	Temperature	150 (–300)°C	170°C	20–40 bar
Dehydrogenation	Pressure	Close to ambient	Close to ambient	3 bar
	Temperature	270–310°C	180–270°C	250–450°C
Price		4 €/kg	40 €/kg	0,3 €/kg

Source: Hurskainen and Ihonen (2020)

The whole process mentioned above aims to deliver RH2 to meet the demand of an industry. In this work, we decided to evaluate the satisfaction of the demand of the transportation industry in the Colombian Caribbean region. This industry was chosen because it consumes 40% of the primary energy consumed in the country (UPME, 2020) and contributes 12% of total GHG emissions (Uniandes, 2021) and 36% of those associated with energy (Van Laake et al., 2021); therefore, decarbonising this industry will contribute greatly to the decrease in emissions and to meeting the country's COP21 commitment.

The objective of this work is to compare different alternatives for the production, storage, and transportation of RH2 to meet the demand of the transportation industry in the Colombian Caribbean region. Section 2 describes the problem to be addressed and explains the economic evaluation method to be used. Section 3 presents the results of the base case and the related discussion. Section 4 presents the design of the evaluated scenarios and their results. Section 5 presents the risk analysis and, finally, Section 6 presents the conclusions and recommendations for future work.

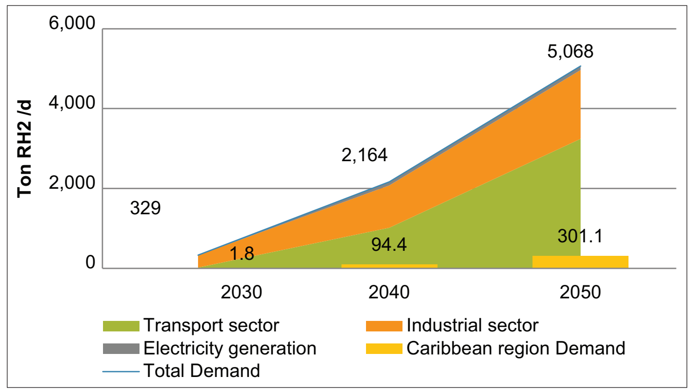
2. METHODOLOGY

This section proposes a simulation model to compare the forms of transport and storage of RH and selects the best alternative depending on the scenario. The selected hydrogen demand is that of the Colombian Caribbean region for the years 2030, 2040, and 2050 and is estimated based on the expected evolution of new hydrogen demand for the transport sector (Minenergía, 2021a) and the number of vehicles in the region according to the latest projections by the Ministry of Transportation (Mintransporte, 2021). Figure 2 shows the expected total demand and the transport sector demand in the Caribbean region.

2.1. Problem Description

The problem addressed is a comparison of alternatives for the production, transportation, and storage of hydrogen. For production we evaluated three types of electrolysers and for transportation and storage: LOHC, GH2 a 200 bar (GH200), GH2 a 350 bar (GH350) and LH2. The aim is to identify the best alternative depending on the system parameters. Figure 3 is a graphical representation of the problem.

Figure 2: Expected total daily demand and transport sector demand



Source: Author's calculation based on data from Minenergía (2021a) and Mintransporte (2021)

From Figure 3 the following alternatives are identified to satisfy the demand. Each alternative proposed meets all demand since the objective is to compare the performance of each alternative. For each alternative in Table 2, there are three possibilities, which correspond to the types of electrolysers (PEM, AEC and SOEC); thus, in total there are 15 HSC configuration alternatives.

2.2. Economic Evaluation Method

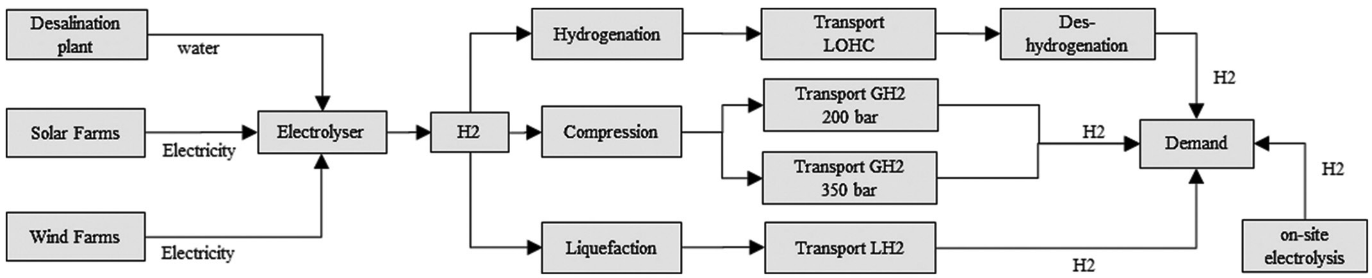
The different options are compared in terms of the total annual cost of hydrogen (C_total_{sf}), which corresponds to the sum of the cost of production ($LCOH_{2sf}$), conversion ($LCOC_{sf}$), storage ($LCOS_f$), transport ($LCOT_f$) and other site costs ($OTHER_f$). The equations used to calculate each cost component are presented below.

$$C\_total_{sf} = LCOH_{2sf} + LCOC_{sf} + LCOS_f + LCOT_f + OTHER_f \left[\frac{U\$}{Kg_{h2}}\right] \quad (1)$$

The CAPEX was annualised using the capital recovery factor (CRF) method using a discount rate equal to WACC and lifetimes ($N_{process}$) depending on the process and previous research.

$$CRF_{process} = \frac{WACC*(1+WACC)^{N_{process}}}{(1+WACC)^{N_{process}}-1} \quad (2)$$

Figure 3: Description of the HSC studied



Source: The authors

Table 2: Alternatives to satisfy the demand

Alternative	H_2 form (*f*)	Transport mode
1	LOHC	Truck
2	GH2	Truck–200 bar
3	GH2	Truck–350 bar
4	LH2	Truck–cryogenic
5	Electrolysis on site	

Source: The authors

2.3. Hydrogen Production Cost

In this study, it is assumed that all the hydrogen required to meet demand will be produced by new electrolysis plants powered by renewable energies (wind or solar); that is, it will be green or renewable hydrogen (RH2). Note that, the correct CAPEX value depends on the investment budget and the specific capabilities of the equipment to be used, but for the purposes of this evaluation, the unit data estimated by NREL will be used (NREL, 2021a, 2021b).

The cost of building and operating wind and solar farms was considered using the levelised cost of energy ($LCOE_s$) method, where *s* corresponds to the energy source used. This method shows the cost per kilowatt-hour delivered and is determined as follows:

$$LCOE_s = \frac{CAPEX_{els} * CRF_{els} + OPEX_{els}}{FLH_{els}} \left[\frac{U\$}{KWh}\right] \quad (3)$$

The capital recovery factor CRF_{el} in Eq. 2 is given by:

$$CRF_{el} = \frac{WACC*(1+WACC)^{N_{el}}}{(1+WACC)^{N_{el}} - 1} \quad (4)$$

Tables 3 and 4 show the values for $CAPEX_{el}$ and $OPEX_{el}$ depending on the scenario.

Similarly, it is assumed that the water required for the electrolysis process will be obtained from new desalination plants. The cost of building and operating these plants was considered using the levelised cost of water ($LCOW_s$) method. Additionally, it is assumed that these plants are at the same location as the electrolyser plant, so no transport is generated between these two echelons.

This method shows the cost per m^3 of water delivered and is determined by Eq. 5.

$$LCOW_s = \frac{\left(CAPEX_{desal} * CRF_{desal} + OPEX_{desal}\right)*24}{FLH_{desal}} + \left(LCOE_s * SEC_{desal}\right)\left[\frac{U\$}{m^3}\right] \quad (5)$$

Eqs. 6 and 7 correspond to the variable costs of operating the electrolyser as a function of the amount of water and electricity used:

$$OPEX_{elecs} = LCOE_s * \frac{LHV_{H2}}{\eta_{elec\_to\_H2}} \left[\frac{U\$}{kg_{H2}}\right] \quad (6)$$

$$OPEX_{waters} = LCOW_s * SWC_{elec} \left[\frac{U\$}{kg_{H2}}\right] \quad (7)$$

Where SWC_{elec} corresponds to the amount of water consumed (m^3) to obtain one kg of H_2, which is expressed in terms of a theoretical minimum consumption SWC_{min} $\left(0.009\frac{m^3}{kg_{H2}}\right)$ Roos (2021), Newborough and Cooley (2021); multiplied by a factor obtained by dividing the amount of water entering the electrolyser (FW) over the amount of electrolysed water (EW). Following the example of Roos (2021), 25% of excess water is assumed.

$$SWC_{elec} = SWC_{min} * \frac{FW}{EW} \left[\frac{m^3_{water}}{kg_{H2}}\right] \quad (8)$$

From the above, the levelised cost per kg of H_2 produced ($LCOH_{2s}$) is calculated, and a value will be obtained for each source of electricity (*s*) and each H_2 form (*f*). The equation to obtain these costs is as follows:

$$LCOH_{2sf} = \left(OPEX_{elecs} + OPEX_{waters}\right) + \frac{\left(CAPEX_{H2} * CRF_{H2} + OPEX_{H2Fix}\right) * LHV_{H2}}{FLH_{H2} * \eta_{elec\_to\_H2}} \left[\frac{U\$}{kg_{H2}}\right] \quad (9)$$

2.4. Hydrogen Conversion Cost

The following equation is used to determine the levelised cost of conversion ($LCOC_s$) per kg of H_2 converted to LOHC and LH2:

$$LCOC_{sf} = \frac{\left(CAPEX_{convs} * CRF_{convs} + OPEX_{fixed\,s}\right)}{FLH_{convS}} + OPEX_{var_{conv}\,s} \left[\frac{U\$}{Kg_{h2}}\right] \quad (10)$$

$$\forall s, \forall f = LOHC, LH2$$

To obtain the LCOC of GH2, the adiabatic compression work W_{comp} is first calculated for each required pressure (t). According to previous works, a five-stage compressor (n = 5) is chosen,

Table 3: CAPEX costs for RE tech

Type	2030			2040			2050		
	Opt	Mod	Cons	Opt	Mod	Cons	Opt	Mod	Cons
LB Wind [U$/KW]	700	950	1000	612,5	855	950	525	760	900
Utility PV [U$/KW]	637.63	775.91	1182.37	559.20	706.77	979.14	480.787	637.63	775.91

NREL (2021a, 2021b)

Table 4: Annual fixed OPEX for RE tech

Type	2030			2040			2050		
	Opt	Mod	Cons	Opt	Mod	Cons	Opt	Mod	Cons
LB Wind [U$/KW-y]	34.38	38.95	43	29.22	36.03	42.03	24.07	33.11	41.05
LB Wind [%CAPEX]	4.9%	4.1%	4.3%	4.8%	4.2%	4.4%	4.6%	4.4%	4.6%
Utility PV [U$/KW-y]	14.99	16.64	20.93	13.69	15.80	18.78	12.45	14.99	16.64
Utility PV [%CAPEX]	2.4%	2.1%	1.8%	2.4%	2.2%	1.9%	2.6%	2.4%	2.1%

NREL (2021a, 2021b)

which allows compression of H2 up to 720 bar with lower energy consumption (Lahnaoui et al., 2018, 2019).

Eq. (11) is based on the derivation obtained by Lahnaoui et al. (2019) from the equations of Jensen et al. (2007).

$$W_{compt} = 0.3229 N * \frac{\gamma}{\gamma - 1} * P_0 \left[\left(\frac{P_t}{P_0} \right)^{\frac{\gamma - 1}{N * \gamma}} - 1 \right] \left[\frac{kWh}{kg_{H2}} \right] \quad (11)$$

Then, the annual energy costs to operate the compressor (Eq. 12) and the capital costs (Eq. 13) are calculated.

$$EC_t = W_{compt} * Ce * \frac{CF}{\eta} \left[\frac{U\$}{kg_{H2}} \right] \quad (12)$$

Following the methods of Drennen and Rosthal (2007), Yang and Ogden (2007) and Lahnaoui et al. (2018, 2019), the first term (Eq. 13) uses a sizing factor of 0.8 to adjust from the baseline size of 4000 kW and cost of 1313 U$/kW determined by the energy and cooling water requirements.

$$CC_t = C_b * S_b \left(\frac{W_{compt} * APH_2}{\eta_c * S_b * CF * TH} \right)^{0.8} \left(\frac{P_t}{P_b} \right)^{0.18} [U\$] \quad (13)$$

The sum of the latter two corresponds to the LCOC for GH_2 (Eq. 14). Table 5 shows the definitions and the values of the different parameters used for the calculation:

$$LCOC_{sf} = \frac{CC_t (CRF_{conv} + OM_{conv})}{APH_2} + EC_t \left[\frac{U\$}{kg_{H2}} \right] \forall f = GH_2 \quad (14)$$

2.5. Hydrogen Storage Cost

The following equation is used to determine the levelised cost of storage (LCOS) per kilogram of LOHC stored:

$$LCOS_{sf} = \frac{CAPEX_{store} * (CRF_{store} + OPEX_{store})}{APH_2} + \frac{+LOHC_{cap} * LOHC_{price} * CRF_{LOHC}}{APH_2} + \frac{LOHC_{deg} * LOHC_{price} * USD}{1 - USD} \left[\frac{U\$}{Kg_{H2}} \right] \forall s, \forall f = LOHC \quad (15)$$

Table 5: Compression related data and assumptions

Parameter	Value	Units
Nconv	Depending on scenario	y
Base compressor cost (Cb)	1,313	U$/KW
Base compressor size (Sb)	4,000	KW
	Depending on scenario	%
hydrogen specific heat ratio (γ)	1.41	
Number of compression stages (N)	5	
Annual delivered useable hydrogen (Cp)	Depending on scenario	Kg/y
P0	1	bar
Pt	Depending on scenario	bar
Pb	200	bar
Cost electrical energy (Ce)	Depending on *LCOEs*	U$/KWh
Capacity Factor (CF)	90	%

Drennen and Rosthal (2007), Yang and Ogden (2007), Lahnaoui et al. (2018) and Lahnaoui et al. (2019)

In this case, two stationary storage tanks are required for both the hydrogen source and utilisation sites (one for the hydrogen rich LOHC and one for the hydrogen lean LOHC) (Hurskainen and Ihonen, 2020). For the other forms (LH2, GH200 and GH350), it is assumed that the number of trailers is three times the number of trucks: one trailer is being transported, one trailer is being filled up at the hydrogen source and one trailer is being emptied at the hydrogen consumer site. The trailers act as storage, and thus, no additional storage is needed.

2.6. Hydrogen Transport Cost

In this case, the truck is assumed to be the same for each delivery method, but four different trailers are considered:

1. A trailer carrying two 200 bar steel bottle containers
2. A trailer carrying a 350 bar glass fibre composite cylinder
3. Container
4. A LOHC tanker trailer
5. A cryogenic liquid tanker trailer.

The following equation is used to determine the levelised cost of transport (LCOT) per kilogram of H2 transported:

$$LCOT_f = \frac{CAPEX_{trucking\, f}}{APH_2} + OM_f + CFuel_f + CPers_f \left[\frac{U\$}{Kg_{h2}} \right] \quad (16)$$

Following the method of Hurskainen and Ihonen (2020), the $LCOT_f$ consists of annual capital expenditure for trucks and trailers ($CAPEX_{trucking}$), operation and maintenance costs (OM_f), fuel costs ($CFuel_f$) and personnel costs ($Cpers_f$) (Eq. 16). The equations used to calculate each part of Eq. 16 are written based on Hurskainen and Ihonen (2020) and given in the supplementary material.

The truck-and trailer-related assumptions are listed in Table 6.

2.7. Other Site Costs

In addition to the costs of production, conversion, and transportation, additional costs were assumed, e.g., from piping, buildings, and engineering ($OTHER_f$).

$$OTHER_f = \frac{CAPEX_{other\,f} * CRF_{other\,f}}{APH_2}\left[\frac{U\$}{Kg_{h2}}\right] \tag{17}$$

The value of $CAPEX_{otherf}$ was estimated based on the data given by (Hurskainen and Ihonen, 2020) assuming that cost growth remains at the same magnitude for higher demand values. Eq. 18 and Eq. 19 show the calculation of $CAPEX_{otherf}$ for each form f, where APH_2 corresponds to the delivered hydrogen per year. For the LOHC and LH2 cases, smaller values were used due to the added complexity caused by the utilisation of steam and low temperatures, respectively.

$$CAPEX_{other\,f} = 139.9 * \frac{APH_2}{350} + 500{,}000\left[\frac{U\$}{Kg_{h2}}\right] \forall f = LOHC, LH2 \tag{18}$$

$$CAPEX_{other\,f} = 92.6 * \frac{APH_2}{350} + 333{,}333\left[\frac{U\$}{Kg_{h2}}\right] \forall f = GH2 \tag{19}$$

2.8. Electrolysis on Site Cost

For on-site production, Eq. 9 considers the electricity and water grid as the supplier of these resources. In this study, it was assumed that neither oxygen nor low-temperature heat from water electrolysis has any additional value.

The following equation is used to determine the levelised cost per kilogram of on-site hydrogen produced:

$$ELEC = OPEX_{grid\_elec} + OPEX_{grid\_water} + \frac{(CAPEX_{site} * CRF_{site} + OPEX_{site}) * LHV_{site}}{FLH_{site} * \eta_{elec\_to\_H2}}\left[\frac{U\$}{kg_{H_2}}\right] \tag{20}$$

3. RESULTS BASE CASE

The base case was defined using the moderate scenario data for 2030 and a one-way distance of 100 km between the production site and the customer. The results of this scenario are presented in Figure 4. When analysing the results presented and the same results for the years 2040 and 2050, for all sources and all transportation alternatives considered, in all scenarios (optimistic, moderate, and conservative), a lower total cost per kg H2 is obtained when using the AEC electrolyser. This is mainly because the production cost ($LCOH_2$) in most cases is the most important cost component, representing a share superior at 55% of the total cost per kgH_2 for all the scenarios.

Table 7 shows the summary of the results for the base case, where, in addition to showing that a lower cost is obtained by using an AEC-type electrolyser in all cases, a lower cost is obtained by using wind energy in most cases. Therefore, it was decided to perform the sensitivity analysis using an AEC electrolyser powered by wind energy for all forms of transport and storage of RH2, with a one-way distance of 100 km and data from the moderate scenario in 2030.

4. SENSITIVITY ANALYSIS

After observing the impact in previous studies of the variation of some parameters on the total cost per kg H2, it was decided to evaluate the effect of varying the parameters of *WACC*, *daily demand* and *one-way distance* between the production site and customer. Additionally, it was decided to vary the *price of electricity* obtained from the grid to determine for which range of electricity prices the on-site production of RH2 is competitive. The results from the variation of these parameters are described below:

4.1. WACC

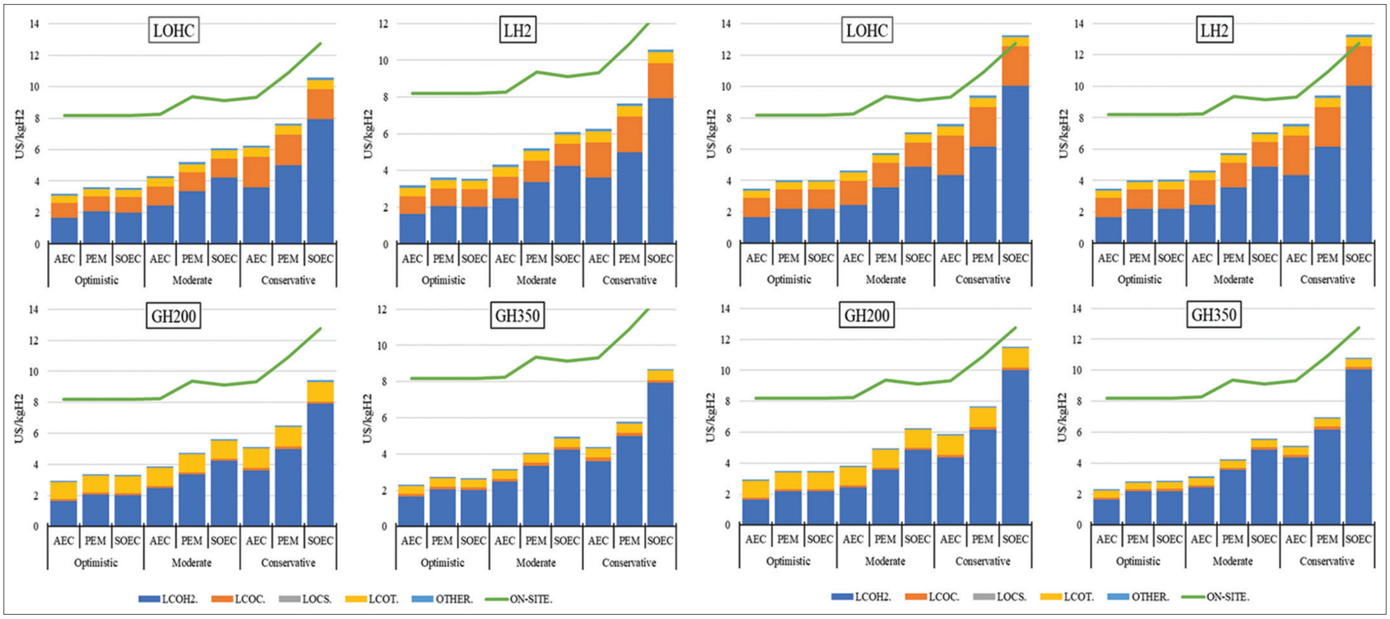
For this parameter, a variation range between 3% and 12% was defined. The results (Figure 5) show that as this parameter increases, the cost per kg H_2 of the alternatives that require higher capital

Table 6: Truck and trailer related data and assumptions

	Truck	LOHC tanker trailer	LH2 cryogenic tanker trailer	GH2 200 bar trailer	GH2 350 bar trailer
CAPEX [kU$]	204	158	650	598	474
Lifetime [years]	8	15	20	15	15
Fix O&M [% of CAPEX]		4%	5%	2%	2%
Var O&M [U$/km]	0.11				
Net H2 payload [kg]		2000	4000	400	900
Unloading & loading time		1h+1h			
Drop-off & pick-up time			1h+1h	1h+1h	1h+1h
Fuel consumption [l/km]	0.45				
Fuel price [U$/l]	0.6				
Average speed [km/h]	65				
Hourly salary [U$/h]	2.6				
Truck availability	80%				

Yang and Ogden (2007), Hurskainen and Ihonen (2020), Minenergía (2021b) and Roos (2021)

Figure 4: Total cost per KgH2 using wind energy (left) and solar energy (right) in 2030



Source: The authors

Table 7: Summary of results base case

Year	Scenery	Electrolyzer	Solar				Wind			
			GH200	GH350	LH2	LOHC	GH200	GH350	LH2	LOHC
2030	Cons	AEC	5.9	5.1	7.6	6.1	5.1	4.4	6.3	5.3
		PEM	7.7	7.0	9.4	7.9	6.5	5.8	7.7	6.7
		SOEC	11.5	10.8	13.3	11.8	9.4	8.7	10.6	9.6
	Mod	AEC	3.8	3.1	4.6	4.2	3.9	3.2	4.3	4.1
		PEM	4.9	4.3	5.8	5.3	4.8	4.1	5.2	5.0
		SOEC	6.3	5.6	7.1	6.6	5.6	5.0	6.1	5.9
	Opti	AEC	2.9	2.3	3.5	3.3	2.9	2.3	3.2	3.3
		PEM	3.5	2.8	4.0	3.9	3.4	2.7	3.6	3.7
		SOEC	3.5	2.9	4.0	3.9	3.3	2.7	3.6	3.6
2040	Cons	AEC	8.6	4.9	6.5	5.5	8.1	4.5	5.5	5.0
		PEM	9.8	6.1	7.7	6.7	9.1	5.5	6.4	6.0
		SOEC	10.5	6.9	8.4	7.4	9.6	5.9	6.9	6.5
	Mod	AEC	7.4	3.4	3.9	3.9	7.4	3.4	3.6	3.9
		PEM	8.1	4.1	4.6	4.6	7.9	4.0	4.1	4.4
		SOEC	8.6	4.6	5.2	5.2	8.3	4.3	4.5	4.7
	Opti	AEC	7.0	2.7	2.8	3.1	7.0	2.7	2.6	3.0
		PEM	7.3	3.0	3.1	3.4	7.3	2.9	2.8	3.3
		SOEC	7.5	3.2	3.3	3.6	7.4	3.0	2.9	3.4
2050	Cons	AEC	16.5	6.0	6.0	5.4	16.4	5.9	5.3	5.3
		PEM	17.1	6.6	6.6	6.0	16.9	6.4	5.8	5.8
		SOEC	16.8	6.3	6.4	5.8	16.6	6.1	5.6	5.5
	Mod	AEC	16.6	4.9	3.8	4.1	16.6	4.9	3.4	4.1
		PEM	16.9	5.2	4.1	4.4	16.8	5.2	3.7	4.3
		SOEC	17.1	5.4	4.3	4.6	16.9	5.3	3.8	4.4
	Opti	AEC	17.1	4.4	2.7	3.3	17.1	4.4	2.4	3.2
		PEM	17.2	4.5	2.8	3.3	17.2	4.5	2.5	3.3
		SOEC	17.6	4.8	3.2	3.7	17.4	4.7	2.7	3.5

Source: The authors

investments, such as LH2 in its conversion process (Figure 5) and GH200 in its transportation (Figure 6), is more affected.

4.2. Demand

For this parameter, a variation range between 1000 and 78,000 kg H2/d was defined. The results (Figure 7) show that the increase in the daily demand of RH2 mostly affects the cost per kgH2 of compressed H2, which is more evident for the GH200. For this reason, from a demand of 52,300 kgH2/d, the GH350 is no longer the best alternative. This is due to the low volumetric density of compressed H2, which requires a greater investment in vessels for its transportation, which, at the same time, generates the need for more vehicles and resulting in an important increase in transportation costs of these forms of RH2 (Figure 10).

Figure 5: Total cost (left) and conversion cost (right) per KgH2 depending on WACC value

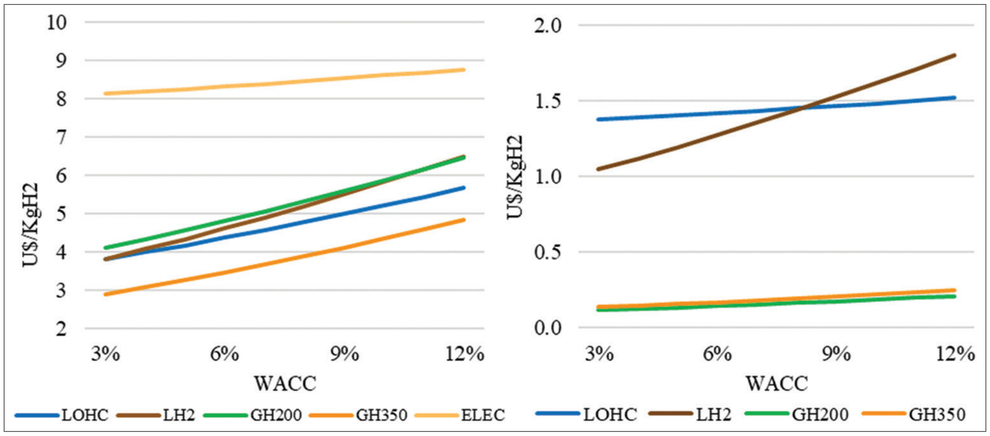
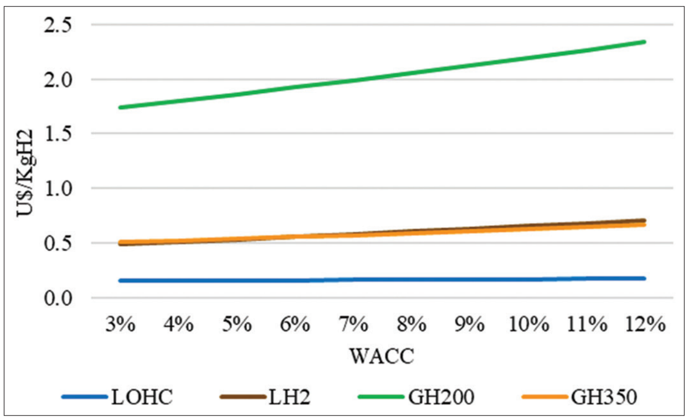


Figure 6: Transportation cost per KgH2 depending on WACC value



Source: The authors

4.3. One-way Distance

A variation range between 50 and 500 km was defined for this parameter. The results (Figure 8) show that similar to what happens with the increase in demand, the alternatives whose cost per kg H2 is most affected are those in which RH2 is compressed, mainly in GH200. Additionally, this alternative, as the distance to be travelled increases, the need for vessels and trucks increases, pushing up transportation costs (Figure 8). It is important to note that from 387 km, LOHCs become the best alternative.

For this parameter, a variation range was defined between 0.025U$/KWh (100 COP/KWh) and 0.200U$/KWh (800 COP/KWh). The results (Figure 9) show that RH2 on-site production is the best alternative with electricity prices below 0.047 U$/KWh (188 COP/KWh) and is competitive with at least one of the other alternatives with prices up to 0.074 U$/KWh (298 COP/KWh).

5. VALUE AT RISK AND CONDITIONAL VALUE AT RISK ESTIMATION

According to Ruíz et al. (2022) VaR is a risk measure that quantifies the market risk of a portfolio of assets and can also be extended to the field of project valuation. It is defined as the maximum expected loss given a confidence level (α) in a specific period. CVaR is a more pessimistic measure than VaR, as it focuses on losses found in the tails of the distributions, i.e., it is estimated as the average of the values that exceed VaR. In this study, the application of this statistic indicates the maximum total cost if an unexpected event occurs. This analysis was carried out using @ Risk in Excel and 10,000 scenarios based on a Monte Carlo simulation, an AEC electrolyser powered by wind energy for all forms of transport and storage of RH2 and data from the moderate scenario in 2030 varying the demand and one-way distance parameters, as shown in Table 8. These parameters are taken as model variables due to the behaviour shown by the total cost per kgH2 in the sensitivity analysis performed with these parameters in the indicated ranges.

Due to the nature of the total cost (cost distribution), the important analyses for its risk evaluation were performed at 10, 5, 2.5% and 1% confidence levels since the unfavourable scenarios are on the right-hand side of the distribution.

5.1. Demand Analysis

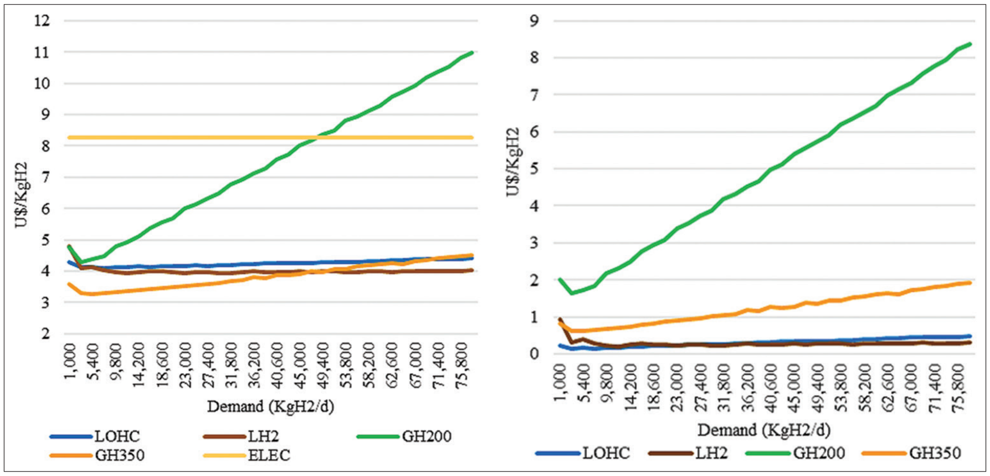
The results obtained by varying the demand values by applying VaR and CVaR risk measures to the total cost indicator are shown in Table 9 for each form of transport and storage RH2. Figures 14 and 15 show the probability histogram of the total cost using LH2 and GH350 as transport and storage forms, respectively.

According to the results in Table 9, the risk assessment with the VaR measure shows that for all the considered confidence levels, the lowest total cost per kgH2 is achieved using the LH2 form for transport and storage RH2.

Focusing on the extreme values of the right side of the distribution (which exceed the VaR), the maximum expected total cost per kgH2 is 8.8677 U$/kgH2. This was the most catastrophic scenario, with 1% confidence using GH200 as a form for transport and storage RH2.

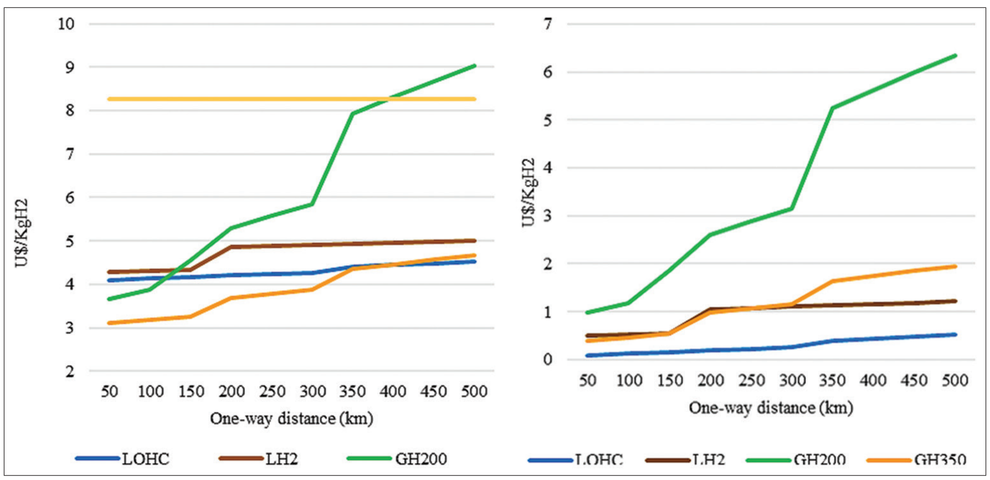
In addition, Figure 16 shows the average share of each cost component according to the simulation results, where the production cost ($LCOH_2$) is the most important cost, except when RH_2 is converted to GH200, in which case the transportation cost (LCOT) is the component that contributes the most to the total cost.

Figure 7: Total cost (left) and transportation cost (right) per KgH2 depending on daily demand value



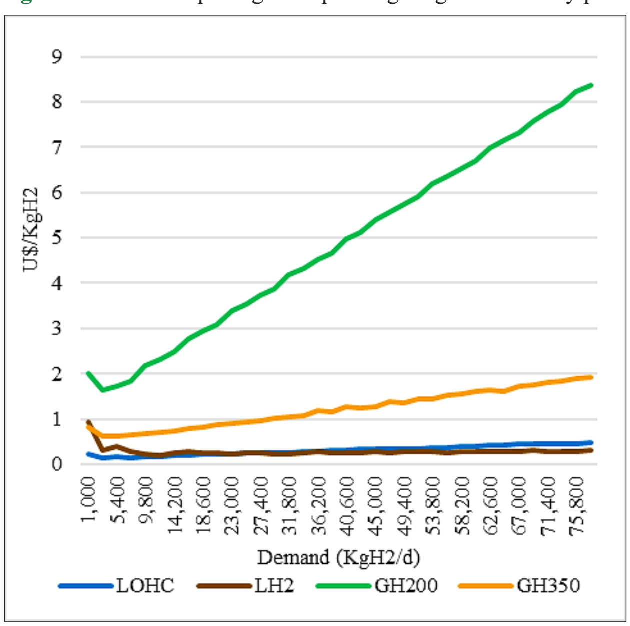
Source: The authors

Figure 8: Total cost (left) and transportation cost (right) per KgH2 depending on one-way distance



Source: The authors

Figure 9: Total cost per KgH2 depending on grid-electricity price



Source: The authors

Table 8: Input variables of the model, where triangular T (min; mode; max)

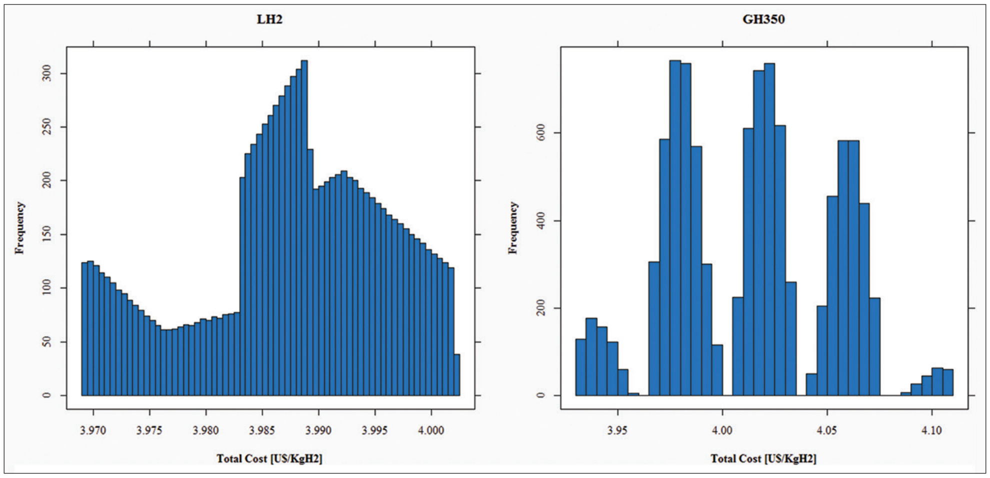
Variable	Units	Input arguments
Demand	kgH2/d	T (45,000; 50,000; 55,000)
One-way distance	km	T (350; 400; 450)

Table 9: VaR and CVaR risk measures of the total cost for demand analysis

Confidence level	VaR of total cost [U$/kgH2]			
	LOHC	LH2	GH200	GH350
10%	4.3047	3.9984	8.6399	4.0636
5%	4.3066	4.0002	8.7166	4.0686
2.5%	4.3074	4.0011	8.7926	4.0730
1%	4.3080	4.0017	8.8112	4.1020
Confidence level	**CVaR of total cost [U$/kgH2]**			
	LOHC	**LH2**	**GH200**	**GH350**
10%	4.3066	4.0002	8.7438	4.0746
5%	4.3074	4.0011	8.7922	4.0832
2.5%	4.3079	4.0016	8.8285	4.0954
1%	4.3082	4.0019	8.8677	4.1056

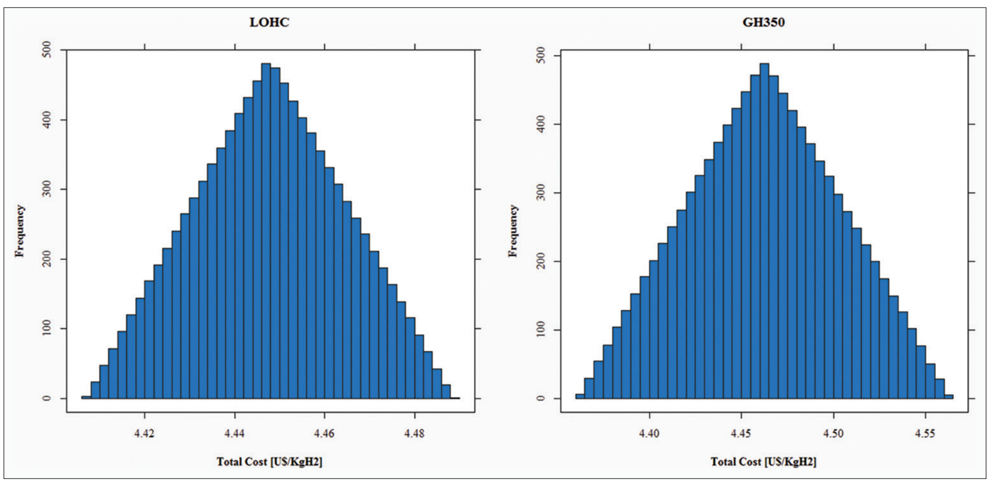
Source: The authors

Figure 10: Probability histogram of the total cost per kgH2 using LH2 (left) and GH350 (right)



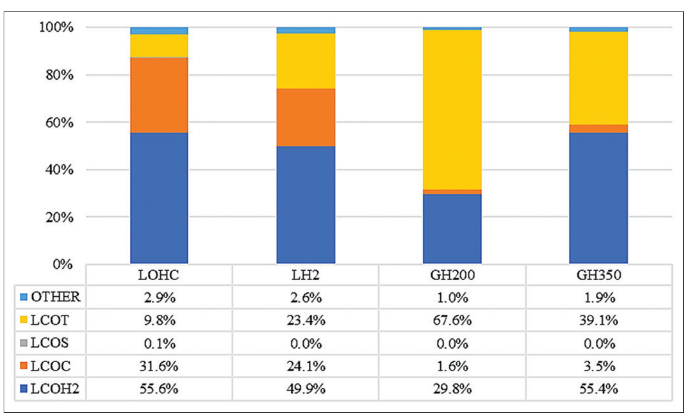
Source: The authors

Figure 11: Probability histogram of the total cost per kgH2 using LOHC (left) and GH350 (right)



Source: The authors

Figure 12: Average share by cost component



Source: The authors

5.2. One-Way Distance Analysis

The results obtained by varying the one-way distance values by applying the risk measures VaR and CVaR to the total cost indicator are shown in Table 10 for each form of transport and storage RH2, and Figures 17 and 18 show the probability histogram of the total cost used as transport and storage from LOHC and GH350, respectively.

Table 10: VaR and CVaR risk measures of the total cost for one-way distance analysis

Confidence level	VaR of total cost [U$/kgH2]			
	LOHC	LH2	GH200	GH350
10%	4.4704	4.9724	8.5082	4.5180
5%	4.4757	4.9760	8.5562	4.5312
2.5%	4.4795	4.9785	8.5903	4.5406
1%	4.4828	4.9807	8.6204	4.5488
Confidence level	**CVaR of total cost [U$/kgH2]**			
	LOHC	**LH2**	**GH200**	**GH350**
10%	4.4764	4.9764	8.5630	4.5330
5%	4.4800	4.9788	8.5950	4.5418
2.5%	4.4825	4.9805	8.6177	4.5481
1%	4.4847	4.9819	8.6379	4.5536

According to the results in Table 9, the risk assessment with the VaR measure shows that for all the considered confidence levels, the lowest total cost per kgH2 is achieved using the LOHC form for transport and storage RH2.

Focusing on the extreme values of the right side of the distribution (which exceed the VaR), the maximum expected total cost per kgH2 is 8.6379 U$/kgH2, and it was the most catastrophic scenario with 1% confidence using GH200 as a form for transport and storage RH2.

In addition, Figure 19 shows the average share of each cost component according to the simulation results, where the production cost ($LCOH_2$) is the most important cost, except when RH2 is converted to GH200, in which case the transportation cost (LCOT) is the component that contributes the most to the total cost.

6. CONCLUSIONS

This paper economically compared different scenarios for the configuration of the renewable HSC. For a moderate scenario with projections to 2030, the best alternative HSC configuration is to produce RH2 using an AEC electrolyser (powered by wind energy) and then transport and store RH2 in the form of GH350. Based on the analysis of other scenarios, for larger WACC values, the LOHC and GH350 alternatives are favoured over LH2 and GH2, which required higher capital investment for their operations, increasing their total cost per kgH2. Additionally, for larger hydrogen demands and especially longer distances, LH2 and LOHC alternatives are favoured over compressed RH2. For grid-electricity price values below \$0.074U (298 COP), producing RH2 on site is competitive with at least one of the other alternatives. Additionally, it is observed that the total cost mainly comprises transportation costs, especially for larger demands and distances, while in the case of LOHC and LH2, it is the production and conversion costs.

For the latter, according to the risk analysis under scenarios of demand uncertainty, the risk of obtaining higher costs per kgH2 is lower if LH2 is used as the form in which RH2 should be transported and stored, and under scenarios of uncertainty in the one-way distance, LOHC should be used, since this form presents the lowest values for the maximum total cost per kgH2.

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