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Techno-economic analysis of in-situ production by electrolysis, biomass gasification and delivery systems for Hydrogen Refuelling Stations: Rome case study

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Abstract

Starting from the Rome Hydrogen Refuelling Station demand of 65 kg/day, techno-economics of production systems and balance of plant for small scale stations have been analysed. A sensitivity analysis has been done on Levelised Cost of Hydrogen (LCOH) in the range of 0 to 400 kg/day, varying capacity factor and availability hours or travel distance for alkaline electrolysers, biomass gasification and hydrogen delivery. As expected, minimum LCOH for electrolyser and gasifier is found at 400 kg/day and 24 h/day, equal to 12.71 €/kg and 5.99 €/kg however, for operating hours over 12 and 10 h/day the differential cost reaches a plateau (below 5%), for electrolyser and gasifier respectively. For the Rome station design, 160 kW_e of electrolysers 24 h/day and 100 kW_{th} gasifier at 8 h/day, LCOH (11.85 €/kg) was calculated considering the modification of the cost structure due to the existing equipment, which is convenient respect the use of a single technology, except for 24 h/day gasification.

Keywords: hydrogen; hydrogen production systems; hydrogen refuelling station

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1. Introduction

In order to reduce greenhouse gas emissions and pollutions, Hydrogen Refuelling Stations "HRS" are developed worldwide. Hydrogen can store energy for long time and its combustion produces only water without causing environmental pollution [1]: moreover, increases in the price of oil have also added impetus to the movement

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towards H_2, and other alternative fuels. That is why the use of hydrogen as transport fuel can be helpful to solve storage and environmental problems. Although both hydrogen vehicles (fuel cell and internal combustion engine) and the related infrastructure have been (and are being) developed and some are commercially available, cost is seen as a major barrier. Given the current state of technology, H_2 could only be competitive with petrol and diesel when produced in sufficiently large quantities, but at the same time a sufficiently large fleet of vehicles to create the necessary levels of demand is needed [2]. Although HRS infrastructure standard size is growing towards 400 kg/day [3–7] a small scale HRS is justifiable for geographical areas where the demand in hydrogen is small in order to provide a minor node [8]. Furthermore in low demand scenarios Simonnet [9] suggests that a small scale approach is more effective, thanks to the modularity of the electrolysers and for financial risk mitigation [9–11]. Furthermore the predictability of the demand (e.g. public transport fleets) is an additional risk mitigation factor [7,12], being able to control demand. The key aim of this paper is to compare and discuss the relative costs of H_2 associated with various production–delivery pathways based on small scale H_2 infrastructure in Rome as a case study, where an existing HRS must be upgraded and integrated to meet the demand of five 12 meters hydrogen buses.

2. System boundary and assumptions

The Rome HRS is designed to produce H_2 from alkaline electrolysis and a biomass gasification, in alternative to delivered compressed hydrogen. Plant auxiliaries are accounted for at a global level. The lifetime of the station is set to 10 years. The system boundary is limited to the production system, the compression system, the storage system and the distribution system as represented in Fig. 1. The inputs are electricity, water and biomass. The only considered output is hydrogen for standard bus refuelling at 350 bar [10,12–14]. Each production method is evaluated through a system efficiency (%) which defined as the ratio between the HHV_{H2} and the required energy input to produce it [15][1].

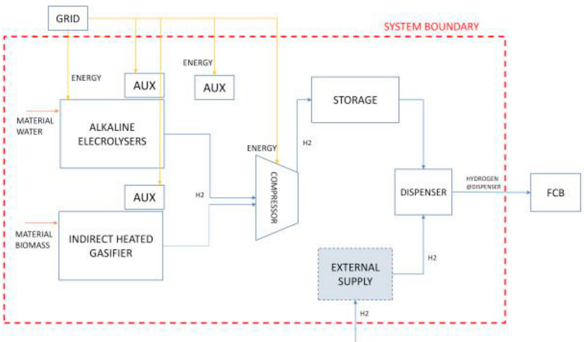


Figure 1 - system boundary

Table 1. Hydrogen Properties and HRS demand

Hydrogen Properties used	
ρ_{H2} density [kg/Nm^3]	0.0898
HHV_{H2} [kWh/kg]	39.39
HRS demand calculation [2,13,14,16]	
Bus route distance [km/(day*bus)]	130
Daily refuelings [units]	1
H_2 consumption [km/kg$_{H2}$]	10
Daily HRS hydrogen demand Q_d [kg/day]	65

The cost assessment is performed via Levelised Cost of Hydrogen “LCOH” (€/kg) [2,12,17–19] calculated as the sum of annualized equipment CAPEX (interest rate i=7% [20,21]) and OPEX (per hydrogen production [2]), according to the actual component’s working hours over the lifetime, divided by the total hydrogen produced (kg). Integration costs (Tab. 8) have been considered as a fixed percentage of the total CAPEX costs.

3. Production systems

3.1. Water electrolysis

In this study we considered alkaline electrolyser, to match the existing one. An electrical substation is assumed to be available close to the HRS in order to provide suitable voltage and current.

[1] In Appendix B of the HHV justification is detailed for electrolysis, and is extended to biomass gasification, since the input is liquid water.

Table 2. Electrolyser data verified with [2,16,18,22–24]

Parameter	value
Ce Electrical Consumption[2] [kWh/ Nm^3]	5.2
C_{aux} auxiliary consumption [kWh/ Nm^3]	10% Ce
Water stoichiometric consumption [l / Nm^3 H_2]	0.85

Table 3. Electrolyser energy parameters [4,6,10,14–16,22–26]

Parameter	Equation	(n°)
Efficiency (%)	$\eta_e = \frac{\rho_{H2} * HHV_{H2}}{C_e}$	(1)
Installed Power (kW_e)	$P_e = (Q_h * c.f._e) * C_e * \left(\frac{24}{h_e}\right)^3$	(2)

Where Q_h is the volumetric hourly demand of hydrogen [Nm^3/h], c.f.$_e$ is the electrolyser capacity factor (%) as the percent of daily demand met, C_e is the specific electrical consumption (kWh/ Nm^3) and h_e the daily availability (h/day).

$\eta_{e,}$ as defined above, is constant and equal to 68% and 61.7%, excluding and including auxiliary consumption. This is aligned with literature values for small scale alkaline electrolyser plants, referenced in Tab 3.

The electrolyser system specific CAPEX is around 4 k€/kW, derived from quotations and aligned with reference small scale figures (referenced in Tab 4). We have not considered scaling factors on electrolyser CAPEX which usually starts for sizes over 1.5 MW, not generally suitable for small scale locally producing HRS. Additional costs for auxiliary and cooling systems are quite marginal for system analysis and are included in the electrolyser CAPEX. LV grid connection costs[4] are 70 €/kW.

Table 4. Electrolyser OPEX (ARERA 2018; ACEA 2018; quotations) [1,7,12,19,24,26,27]

item	type	[h/week]	Cost [€/kWh]; [€/l]; [%]
Grid Electricity (Italy)[5]	T1 (peak)	55	0.08255
	T2 (intermediate)	41	0.08014
	T3(off-peak)	72	0.06739
Tap Water	Fixed	168	0.00526
O&M Alkaline electrolyser	% over CAPEX	Depending on electrolyser operation hours	(5% CAPEX)/year

Only energy quota has been considered in order to compare results with other studies [10,14,26,28]. Water consumption is quite marginal respect to the electricity input for the electrolysis. O&M costs are considered over the actual availability hours of the electrolysers, where in the calculations a "maintenance year" corresponds to 8760 hours of continuous operation. The O&M percentage results higher than the gasifier since it includes cell replacement at the end of its lifetime.

3.2. Biomass gasification

We considered an indirect fluidized bed (steam in gasifier, air in the combustor) gasifier coupled with a Water Gas Shift (WGS) reactor and Pressure Swing Adsorbtion (PSA) system, and electrical auxiliaries [22,29]. The system is available for the HRS from the European project UNIFY.

The gasification data used in this analysis are taken from Pallozzi [30] and are shown in table 5.

Table 5 Operating conditions of gasifier (UNIFHY project) [30]

Parameter	Value	Electrical consumptions	kWe in 1MWth plant	kWe in 100kWth plant
Steam to Biomass (S/B) ratio	1 $kg_{steam}/kg_{biomass}$	Water pump	Negligible	Negligible
Hydrogen yield	67 $g/kg_{biomass\ dry}$	PSA compressor	44	4.4
Hydrogen pressure out PSA	3 bar			
Biomass $HHV_{biomass,dry}$	5.42 kWh/kg	Total	70	7

Parameter	Equation	(n°)
Gasifier Efficiency (%)	$\eta_g = \frac{Q_g * \rho_{H2} * HHV_{H2}}{\dot{M}_{biomass} * HHV_{biomass,dry}}$	(3)
Total gasifier specific energy consumption (kWh/$Nm^3{}_{H2}$)	$C_g = \frac{\dot{M}_{biomass} * HHV_{biomass}}{Q_g} + \frac{P_{aux}}{\eta_{aux} * Q_g} = C_{g_b} + C_{g_e}$	(4)
Installed power gasifier (kWth)	$P_g = \dot{M}_{biomass} * HHV_{biomass}$	(5)

2 Real electrolyser consumption has been considered for PIEL model Quindicimila, courtesy of A.G.T. Considering fixed output pressure and electrolyte temperature (3 bar and 75°C) and proportional auxiliary consumption the thermodynamic and system efficiency can be considered constant with flow rate.
3 We note that without electrolyte cooling systems, $Q_{h,max}$ can be limited respect to $Q_{h,nom}$ if continuous operation is required.
4 ARERA "Non-domestic clients for installed power >16,5 kW" tables 2018
5 All systems are considered able to prioritize the electricity consumptions time windows, in case of discontinuous operation.

Where $HHV_{biomass}$ is in (kWh/kg) of the chosen biomass, in this case nutshell, $M_{biomass}$ the biomass flow rate (kg/h) and Q_g (Nm^3/h) is given by the capacity factor $c.f._g$ (%) and availability (h/day) of the gasifier by the hydrogen yield. Each set of parameters corresponds to a gasifier nominal power (kW_{th}) calculated with (5) on $M_{biomass}$. The hydrogen efficiency, equal to 48.7% and 45.5% excluding and including auxiliaries respectively, is comparable to state of art figures [16,31–34].

Cost analysis for the biomass gasification plant components is taken from [21] which provides an extensive techno-economic analysis and scaling factors for different configurations:

$$SC = RC * \left(\frac{SP}{RP}\right)^{exp}; \quad (6)$$

- SC: Scaled cost for each component
- exp: Exponent [35]
- RC: Reference costs [21]
- SP: Scaling parameter (kW_{th} considered)
- RP: Reference Parameter (kW_{th} reference)

Item	Cost
Biomass cost	60 €/ton [6]
Tap Water	0.00481 €/litre
O&M Gasifier	(2% over CAPEX)/ year

Table 6. Gasifier OPEX [20,21]

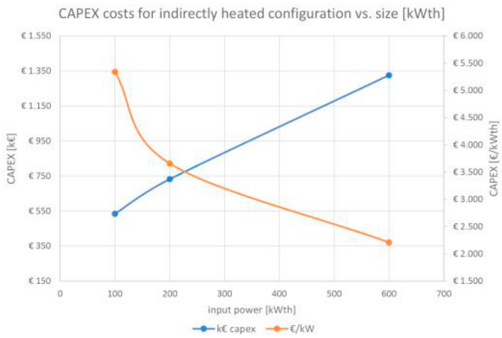


Figure 2 - gasifier CAPEX costs vs. size (kW_{th})

In Fig. 2 biomass gasification plant CAPEX (mainly composed by gasifier, WGS and PSA) and specific CAPEX are reported in function of input size from 100 to 600 kW_{th}. A different slope in specific CAPEX is observed for different sizes. The obtained costs are lower respect to small scale biomass plants - between 5÷10 k€/kWth quoted in [36] – but are higher respect to the costs reported by [37], considering differences in scale.

Auto-production of electricity by burning syngas in an ICE, considering 100 kWth gasifier parameters, leads to an electricity price OPEX of approximately 85÷90 €/MWh_e (ICE η_{el}=25.3% [38]), which is comparable to electricity from the grid. Therefore, does not introduce a relevant advantage. In addition, adding the ICE CAPEX and increasing the overall complexity of the HRS (3 systems are present at the same time) is generally less convenient. Auto-production can become a favourable option in case of expensive electricity and/or cheap biomass.

3.3. Delivery

Compressed hydrogen is supplied by trucks or tube trailer at 200 bar – standard pressure for hydrogen delivery [7,10,39,40]. An average flow rate way is defined over the period of deliveries. The recompression up to 400 bar is included in the compressor consumption described below[7].

Table 7. Hydrogen delivery parameters and costs

Parameters for a single delivery @200 bar [quotations]	Trucks	Tube Trailer [24]
Configuration	90 x 50 litre	20.000 litre
Stored quantity (Nm^3; kg)	900; 80.9	4000; 359.2
CAPEX [7,12,41] – fixed with delivery frequency		
HRS modifications (civil works) [14,28]	10,000 €	100,000 €
Gas connection system	5,000 €	10,000 €
OPEX [24,42]		
H_2 retail cost	10 €/kg	7,50 €/kg
Vehicle leasing cost for availability	800 €/(month*vehicle)	2,150 €/(month*vehicle)
Transport reference cost[8]	0,296 €/km + 20% profit	0,423 €/km + 20% profit

[6] biomass cost is considered constant in time and not suffering seasonal variability. In fact, a variation of 300% the biomass cost is less relevant respect to the variation of the CAPEX, increasing the final cost only by 10÷20% according to availability hours. Transport cost is shadowed into the biomass cost.
[7] This is a conservative approach since delivered hydrogen could be directly used for cascade refueling at low initial vehicle refueling pressures, leading to energy and cost savings.
[8] Cost calculated for by Italian Ministry of Infrastructure and Transport with diesel cost (2011) in Italy based on 15t and 40t trucks respectively.

4. Balance of plant

Downstream the hydrogen production and auxiliary systems, the HRS Balance of Plant (BOP) is composed of the compressor, the storage and the dispenser systems and the integration components:

Table 8. Balance of plant parameters

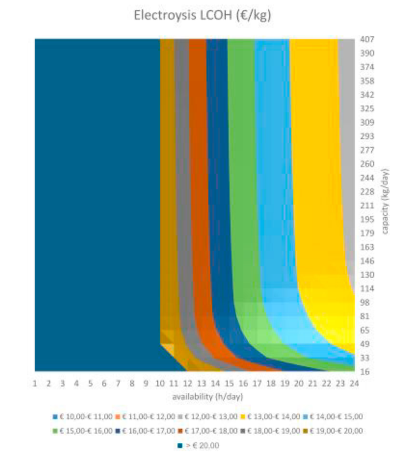
		Compressor Reciprocating up to 400 bar	Storage @400 bar	Dispenser x1 Fast filling – 350 bar in FCB	Integration (pipeline; electrical and civil works; permitting; financial)	Plant auxiliary 24h/24 (blowers, safety systems, lighting, etc.)
Sizing criteria		Maximum production flow rate	1 day of storage [2,14,28,43,44]	Demand (kg/day)	-	P=5% P_{tot} (kWe or kWth); minimum 20kWe
Energy		Isoentropic transformation[9] $\eta_{compression/motor}$=0.56 [7] 20% of C_c intercooling	-	-	-	η_{aux}=0.97
Cost [7,12,19,24,27,42]; quotations and estimates						
CAPEX (purchase and installation)		7 k€/kW$_e$ incl. cooling system + grid connection cost	1,000 €/kg$_{H2}$ stored	500 €/(kg/day)	20% sum of total CAPEX	200 €/kW$_e$ + grid connection cost
OPEX	electricity	T1, T2, T3 reported in Tab.4	-	-	-	T1, T2, T3 reported in Tab.4
	O&M	5 %CAPEX/year	1%CAPEX/year	10%CAPEX/year	-	20%CAPEX/year[10]

From an energy point of view the only active components are the compressor and the plant auxiliaries, since storage, dispenser and integration are passive components or in any case assumed to be included in the plant auxiliaries.

5. Sensitivity analysis. Results and discussion.

Sensitivity analysis has been performed on the LCOH (€/kg) varying two parameters for each technology separately. For electrolyser and gasifier, c.f. and availability (h/day) have been varied, from 0% to 625% respect to the defined demand (65 kg/day) – meaning from 0 to approximately 400 kg/day and from 0 to 24 (h/day); the gasifier option is more subject to sensitivity due to the scaling factors [21,45] respect to electrolysis. For trucks and tube trailer travel distance and delivery frequency have been varied from 25 to 500 km and from 25 to 400 kg/day, respectively. The sensitivity analysis considers the relationships between the production systems and the balance of plant. LCOH contour maps and the intersection of the sensitivity for 65 kg/day and differential cost curves ($\Delta LCOH_{i-1 \rightarrow i}/LCOH_{i-1}$ in orange) are represented for electrolysis and gasification in Fig. 3, while only contour maps are reported for delivery:

a)



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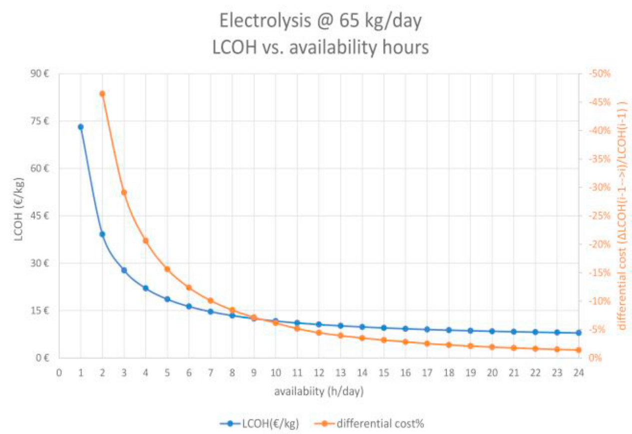
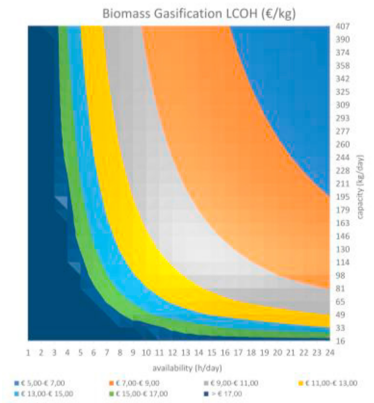


[9] Calculating adiabatic transformation is conservative since it is usually multi-staged with intercooling, following a more isothermal path whose compression work required is reduced. An equivalent p_{1eq} is calculated to account for the decrease of pressure of the vessels with its' discharge.
[10] 24h/24 is another conservative assumption since some auxiliary systems operate in limited amounts of time [42].

c)



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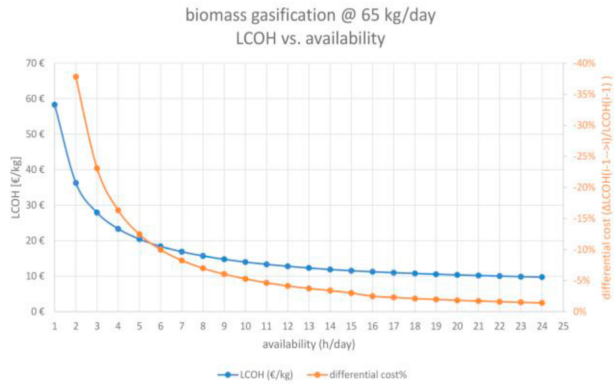
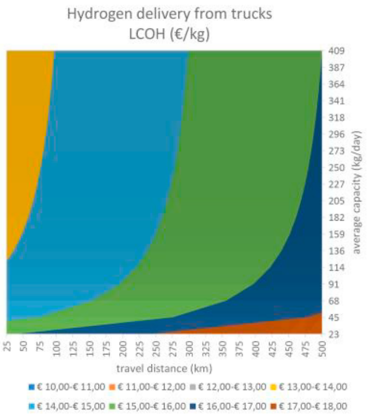


e)



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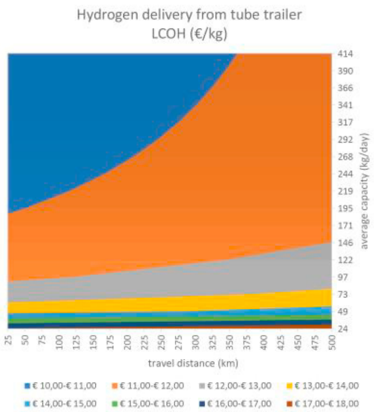

Figure 3 – LCOH (€/kg) for a) electrolysis map; b) electrolysis 65 kg/day; c) gasifier map; d) gasifier 65 kg/day; e-f) delivery maps

For electrolysis, LCOH is greatly influenced (up to 46% by increasing availability hours from 8 to 24 h/day) by the availability hours (Fig. 3b) benefiting the decrease of CAPEX cost for smaller electrolysers which is not balanced by electricity cost reduction in off-peak hours. The minimum LCOH is found for maximum c.f.$_e$ and 24 h/day (12.71 €/kg) corresponding to a size of 981 kW$_e$. However, a plateau region – where the differential cost becomes less than 5% - is already reached over 12 h/day, corresponding to 314 kW$_e$. Inconvenience of oversizing electrolysers in small scale HRSs is also mentioned also by [11,12,19].

For gasification, fig. 3c-d, both c.f.$_g$ and availability hours impact relevantly the LCOH, up to 68% and 40% respectively. The minimum LCOH is found for maximum c.f.$_g$ and 24 h/day, equals to 5.99 €/kg corresponding to the size of 1370 kWth. However, from the analysis of the differential cost the plateau regions, are reached for c.f.$_g$ over 175% corresponding to 384 kWth (24 h/day) and for over 10÷11 h/day in case of discontinuous operation.

The delivery sensitivity, fig. 3e-f, shows that LCOH dependence on travel distance always favours shorter travel distances but is quite limited in impact, 15% and 7%, while scale affects LCOH up to 14% and 41%, for the trucks and trailer cases respectively. Minimum LCOH is found at 400 kg/day and 25 km for both delivery options. LCOH of trucks overcome that of trailers for a capacity of approximately 34 kg/day considering 100 and 250 km, respectively. In table 9 are reported the costs for each configuration at 65 and 400 kg/day.

Table 9. LCOH results for 65 and 400 kg/day

Item	65 kg/day LCOH (€/kg$_{H2}$)	400 kg/day LCOH (€/kg$_{H2}$)
Electrolysis (24h/day)	13.32	12.71
Biomass gasification (8 h/day)	15.70	9.93
Biomass gasification (24 h/day)	9.72	5.99
Delivery trucks (100 km) *	14.73	14.02
Delivery trailer (250 km) *	13.05	10.83

*the trucks refill in smaller production plants which are closer to the HRS respect to trailers' refilling plants

6. The Rome case study

The analysis was applied to the Rome station considering refurbishment costs for 120 kW_e electrolysers and 100 kW_{th} gasifier instead of purchase cost as in [14]. The gap with the demand is completed by a new 40 kW_e alkaline electrolyser (for reliability issue) operating 24 h/day. The gasifier is foreseen to operate 8 h/day to reduce the OPEX.

The LCOH sums to 11.85 €/kg, which is convenient respect to other options presented in Tab. 9, except for gasification 24 h/day, even considering a slight 15% oversizing for contingency issues as shown in figure 4.

a)

Technology	c.f.	CAPEX	OPEX	LCOH
	[%]	[€/kg H2]	[€/kg H2]	[€/kg H2]
Electrolysis	100%	€ 1.30	€ 7.50	€ 8.80
Gasification	15%	€ 0.00	€ 0.24	€ 0.25
Delivery	0%	€ 0.06	€ 0.00	€ 0.06
BoP	100.00%	€ 1.62	€ 1.13	€ 2.75
TOT	115%	€ 2.97	€ 8.88	€ 11.85

b)

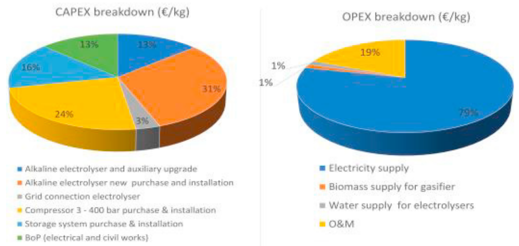

Figure 4 – Rome HRS a) hydrogen cost repartition and b) breakdown

The following charts show the breakdown of the CAPEX and OPEX costs, where the most relevant costs are electricity cost (6.97 €/kg) and O&M (1.65 €/kg). Electrolyser CAPEX (1.30 €/kg) is relevantly lower than OPEX (7.50 €/kg) due to the extensive utilization of refurbished equipment. Importance of electricity cost and availability hours (size) is easily seen.

7. Conclusions and perspectives

The costs of small scale HRS (from around 65 kg/day), which implement locally producing systems – such as electrolysis and biomass gasification – are comparable to those for delivery solutions, therefore it makes sense to investigate real case consumptions and costs.

1) With electricity cost ranging between 82.55 €/MWh and 67.39 €/MWh it is more convenient to increase operating hours of electrolysers rather than size. The opposite behaviour can be appreciated for electricity cost reduction over 50% between peak and off-peak hours, considering the same time windows (e.g. 0.18 c€/kWh peak and 0.08 c€/kWh off-peak). The minimum LCOH – for continuous operation and 400 kg/day– is 12.71 €/kg for around 1 MW_e, but already at 12 h/day the differential cost plateau is reached.

2) Although biomass gasification presents a lower energy efficiency (48.72 % vs. 68.02% of electrolysis, calculated on HHV excluding auxiliaries) the analysed technology is promising due to lower biomass costs, which is sensibly lower than electricity cost. The lowest LCOH is obtained at 1370 kW_{th} for 400 kg/day and for 24 h/day (5.99 €/kg). Operating conditions at 10 h/day reach differential cost plateau.

3) Delivery hydrogen is more convenient for smaller scales than the considered one with the considered retail price. Costs for 65 kg/day HRS capacity are comparable with locally producing ones. In case of tube trailers small scale cases suffer more than trucks from the higher CAPEX costs related to vehicle leasing and HRS civil works modifications. Trailers can potentially reach more convenient LCOH, up to 10.5 €/kg at 400 kg/day respect to trucks, which can only reach 13.67 €/kg. Trucks are more convenient respect to trailers below 34 kg/day for the considered travel distances.

The Rome case study LCOH is 11.85 €/kg, thanks to the use of in kind. The use of electrolysers at 100% $c.f._e$ and the implementation of the gasifier for 8 h/day are due to reliability issues, although 24 h/day gasification has the possibility to reduce further the LCOH.

Large scale implementation of HRS and increase in the hydrogen demand for mobility would increase the capacity factor for HRSs at larger produced volumes, allowing to install more optimal sizes, reduce specific costs and reach competitive LCOH values. If the delivery hydrogen costs do not decrease sufficiently this will favour local production.

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