Supplementary material to *"Quantifying global costs of reliable green hydrogen."*

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Contents

Appendix A Methods

A.1. PEMEL investment costs

This economic analysis is based on the production of *PEMEL*s having a capacity of 1 MW (400 kg H_2/d), according to the inventories reported by Bareiß *et al.* [1] and the National Renewable Energy Laboratory (*NREL*) [2]. According to this, the demand for H_2 will be satisfied by increasing the number of electrolysers up to the desired production rate. The stack is manufactured in-house, while the elements of the *BOP* are outsourced. The system specifications considered for the stack are presented in Table A-1.

Table A-1. System specifications for the PEM electrolysis system analysed.

Specification	Quantity
Stack power (kW)	1,000
Cell voltage (V)	1.7
Current density (A/cm^2)	1.7
Power density (W/cm^2)	2.9
Cell efficiency (%)	86
Anode loading (mg/cm^2)	Ir: 2
Cathode loading (mg/cm^2)	Pt: 0.75
Membrane thickness (µm)	200
Single-cell format area (cm^2)	957
Active cell format area (cm^2)	748
Total active area (m^2)	34.7
Number of cells per system	510
Stacks per system	2
Cells per stack	255
H_2 production (kg/d)	400

The cost per electrolyser of 1 MW capacity was calculated using the material costs reported in Table A-2. Economies of scale are applied, including learning curve rates from 0 to a maximum of 18% for the stack, 8% for anode and cathode catalysts, 12% for the power supplies, 7% for the gas conditioning, and 10% for the remaining elements of the *BOP* [3,4]. The manufacturing costs of the stack were calculated following the procedure reported by the *NREL*, which serves as a proxy to estimate the manufacturing costs [2]. Regarding markup and installation, we applied the factors for stationary *PEM* fuel cell systems proposed by James and DeSantis [5]. Their report concludes that a markup rate of 50% is a representative value with no account for recurring engineering or equipment warranty. This value also correlates to a 33% gross margin and represents a mature, established business. To include variations of this element in the cost of the electrolyser, we consider a range between 20 and 70% of the *CAPEX* of the electrolyser. Similarly, the installation factor is considered from 1.33 to 1.83 [5].

The cost of the electrolyser is finally determined by sampling the learning curves of the corresponding elements according to the ranges described assuming a normal distribution with a standard deviation (*SD*) being one-sixth of the corresponding ranges. A total of 3,000 independent samples were considered for each component of the electrolyser.

Table A-2. Reference cost for raw materials and outsourced equipment

Element	Cost (USD/unit)	Reference
Platinum (g)	24.9	[6]
Iridium (g)	34.2	[6]
Gold (g)	41	[6]
Titanium (kg)	35	[6]
Steel (978 cm^2 pc)	5	[2]
Aluminium (kg)	15.4	[6]
Nafion® membrane (30x30cm pc)	200	[7]
Power Supplies (per electrolyser 1 MW)	198,565	[2]
Deionised H_2O Circulation (per electrolyser 1 MW)	87,082	[2]
H_2 Processing (per electrolyser 1 MW)	83,880	[2]
Cooling (per electrolyser 1 MW)	28,678	[2]
Miscellaneous (per electrolyser 1 MW)	6,000	[2]

From this analysis, current costs of 1,750 ± 350 USD/kW (for 100 electrolyser units per year) and future costs of 1,000 ± 350 USD/kW (assuming 50,000 electrolyser units per year) were obtained, as shown in Figure A-1. At this last level of production, learning seems to be steady without significant improvements beyond this point. The manufacturing costs of the stack reach 180 ± 50 USD/kW, with materials being the main contributors. The *CCM* is the most expensive stack component, representing 78% of the cost. Within the *CCM*, the Nafion® membrane represents 63% of the cost, iridium coating 28%, and platinum coating 8%. The *BOP* shows a contribution of 260 ± 70 USD/kW, representing 63% of the total capital costs. From the elements of the *BOP*, the power supplies represent 43% of the costs, H_2O circulation 24%, and H_2 processing 23%. The markup installation factor accounted for 200 ± 110 USD/kW, resulting in total uninstalled costs of 640 ± 200 USD/kW. This value agrees with [3], 550 USD/kW for the same relative cumulative production. The installation factor represented an additional 360 ± 180 USD/kW. These costs represent a minimum obtained when cumulative installed capacity increases 500-fold. Assuming an existing installed capacity of 1 GW [8], these costs would be attained when 500 GW of *PEMEL*s are installed. Coincidentally, this value would represent a value close to the current H_2 production level if operating at full load (73 Mt H_2). If we now consider the projected plan of the *EU* to produce 10 Mt H_2 by 2030 (≈70 GW at full load) [9], installed costs would reach 1,250 ± 350 USD/kW, while uninstalled costs would represent 780 ± 180 USD/kW. These costs agree with those reported by [10], who reported uninstalled values of 920 USD/kW by 2030.

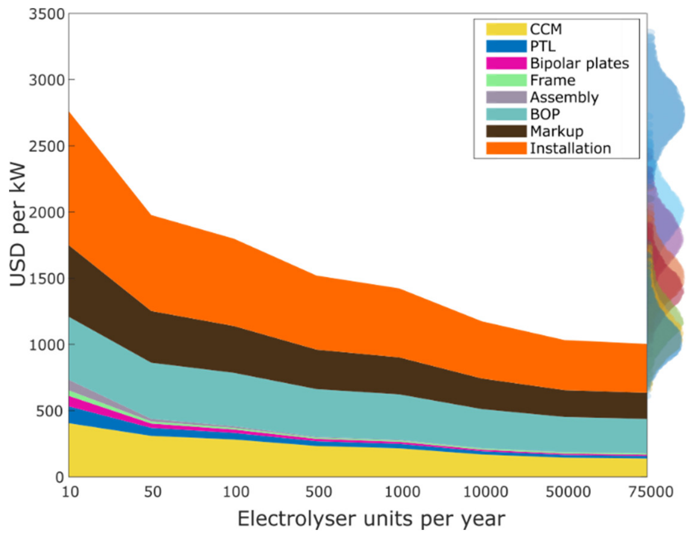

Figure A-1. Installation costs for 1 MW *PEMEL*. *CCM*: Catalyst-coated membrane; *PTL*: Porous transport layer; *BOP*: Balance of plant. Stack is produced in-house, while *BOP* is outsourced. Individual learning rates ranges are considered for the stack (0-18%), catalyst (0-8%), power supplies (0-12%), gas conditioning (0-7%), and remaining elements of the *BOP* (0-10%). Markup represents 20-70% of the production cost, and installation factors 33-83% of the total cost of the electrolyser. 3,000 independent samples were considered following a normal distribution.

A.2. Hydrogen net production cost (NPC)

The *NPC* of green H_2 is calculated as follows:

A.2.1. Scenario 1: Excluding the potential savings from the sale of surplus electricity

The *NPC* of green H_2 is computed using the capital expenditure (*CAPEX*) and the design capacity of the processes (solar *PV*, wind, *PEMEL*) and energy storage (H_2 or electricity) units determined by the γ–*AW:E* model for each location. The operational expenditure (*OPEX*) is not included in the *NPC* calculation as it is deemed negligible-raw materials (H_2O, sunlight and wind) are abundant, utilities (electricity) are explicitly modelled and fixed *OPEX*, such as labour costs, are minor compared to the *CAPEX*. The fixed capital investment (*FCI*) is then calculated as the sum of all *CAPEX*. Working capital (*WC*), which has no depreciation, is estimated to be 10% of total capital investment (*TCI*) [11]. The *TCI*, which is the sum of the *FCI* and *WC*, is then annualised using the following equation:

$$\mathrm{ACC}_{\mathrm{H_2,\ excluding\ savings}} = \mathrm{FCI}_{\mathrm{H_2}} \cdot \left(\frac{\mathrm{ROE} \cdot (1+\mathrm{ROE})^t}{(1+\mathrm{ROE})^t - 1} + \frac{\mathrm{ROE}}{9} \right) \tag{1}$$

Where *ACC* denotes the annualised capital cost, *ROE*, the return on equity and *t*, the plant lifetime. The *WC* is represented in the equation's second term.

Finally, the *NPC* of green H_2 (expressed in USD/kg) is computed by dividing the *ACC* by the annual production (*AP*), as shown below:

$$\mathrm{NPC}_{\mathrm{H_2,\ excluding\ savings}} = \frac{\mathrm{ACC}_{\mathrm{H_2,\ excluding\ savings}}}{\mathrm{AP}_{\mathrm{H_2}}} \tag{2}$$

The model's cost input data can be found in Appendix B.

A.2.2. Scenario 2: Including the potential savings from the sale of surplus electricity

To assess the potential savings from the sale of surplus electricity over the *NPC* of green H_2, we first calculate the *NPC* of the total electricity being generated from the installed solar *PV* and wind systems by the procedure described below:

i) The total electricity produced from the hybrid system is calculated as follows:

$$\text{Electricity produced} = \text{Installed capacity}_{\text{solar}} \times \text{CF}_{\text{solar}} + \text{Installed capacity}_{\text{wind}} \times \text{CF}_{\text{wind}} \tag{3}$$

ii) The surplus electricity available for sale is obtained as shown below:

$$\text{Surplus electricity} = \text{Electricity produced} - \text{Electricity used for } \mathrm{H_2} \text{ production} \tag{4}$$

iii) The *FCI* of the hybrid electricity system and the *NPC* of the electricity generated are calculated according to the equations below:

$$\text{FCI}_{\text{electricity}} = \text{Installed capacity}_{\text{solar}} \times \text{CAPEX}_{\text{solar}} + \text{Installed capacity}_{\text{wind}} \times \text{CAPEX}_{\text{wind}} \tag{5}$$

$$\mathrm{NPC}_{\mathrm{electricity}} = \frac{\mathrm{ACC}_{\mathrm{electricity}}}{\mathrm{AP}_{\mathrm{electricity}}} \tag{6}$$

Finally, the *NPC* of green H_2, including the potential savings from the sale of surplus electricity (expressed in USD/kg), is calculated as follows:

$$\text{Revenue from the sale of surplus electricity} = \text{Surplus electricity} \times \mathrm{NPC}_{\mathrm{electricity}} \tag{7}$$

$$\mathrm{NPC}_{\mathrm{H_2,\ including\ savings}} = \frac{\left(\mathrm{ACC}_{\mathrm{H_2,\ excluding\ savings}} - \text{Revenue from the sale of surplus electricity}\right)}{\mathrm{AP}_{\mathrm{H_2}}} \tag{8}$$

A.3. Cost of intermittency

A.3.1. System capacities

The annual availability of wind electricity ($\mathrm{kWh_{produced}/kW_{installed}}$) is calculated as follows:

$$\text{total wind} = \sum \left(\mathrm{CF}_{\text{in one year}}\right) \tag{9}$$

The annual wind electricity demand of the baseline system is calculated as shown below:

$$\text{total wind}_{\text{baseline}} = \text{Annual production of green } H_2 \times \text{Electrolyser's electricity demand} \tag{10}$$

The capacity of the (wind) baseline system is obtained as follows:

$$\text{Wind capacity}_{\text{baseline}} = \frac{\text{total wind}_{\text{baseline}}}{\text{total wind}} \tag{11}$$

Where:

$\mathrm{CF}_{\text{in one year}}$ is expressed in $\mathrm{kWh_{produced}/kW_{installed}}$; the annual production of green H_2 in $\mathrm{kg_{H2,g}}$/yr; the electrolyser's electricity demand in $\mathrm{kWh_{electricity}/kg_{H2,g}}$ and, the wind $\mathrm{capacity_{baseline}}$ in kW.

A.3.2. System costs

Once the *CAPEX* and the design capacity of the processes ($CAPEX_{\mathrm{solar}}$, $CAPEX_{\mathrm{wind}}$, $CAPEX_{PEMEL}$ and C_{solar}, C_{wind}, C_{PEMEL}, respectively) and energy storage units ($CAPEX_{\mathrm{H2}}$, $CAPEX_{\mathrm{electricity}}$ and T_{H2}, $T_{\mathrm{electricity}}$, respectively) are determined by the γ–*AW:E* model for each location, the optimal fixed capital investment for the baseline system (FCI_{baseline}), *i.e.*, the system where the capacity factor is constant at the annual average, is calculated as follows:

$$\text{CAPEX wind}_{\text{baseline}} = \frac{\text{CAPEX}_{\text{wind}} \times \text{Wind capacity}_{\text{baseline}}}{C_{\text{wind}}} \tag{12}$$

$$\text{CAPEX PEMEL}_{\text{baseline}} = \frac{\text{CAPEX}_{\text{PEMEL}} \times \text{Hourly production of green } H_2}{C_{\text{PEMEL}}} \tag{13}$$

$$\text{FCI}_{\text{baseline}} = \text{CAPEX wind}_{\text{baseline}} + \text{CAPEX PEMEL}_{\text{baseline}} \tag{14}$$

Finally, the fixed capital investment associated with the intermittency is calculated according to the equation below:

$$FCI_{intermittency} = FCI_{optimal\ system} - FCI_{baseline} \quad (15)$$

The $FCI_{intermittency}$ is then annualised and converted to USD/$kg_{H2,g}$ (from Eq.1 and Eq. 2), which value represents the cost of intermittency of the system.

Appendix B Input data for γ–*AW:E* model

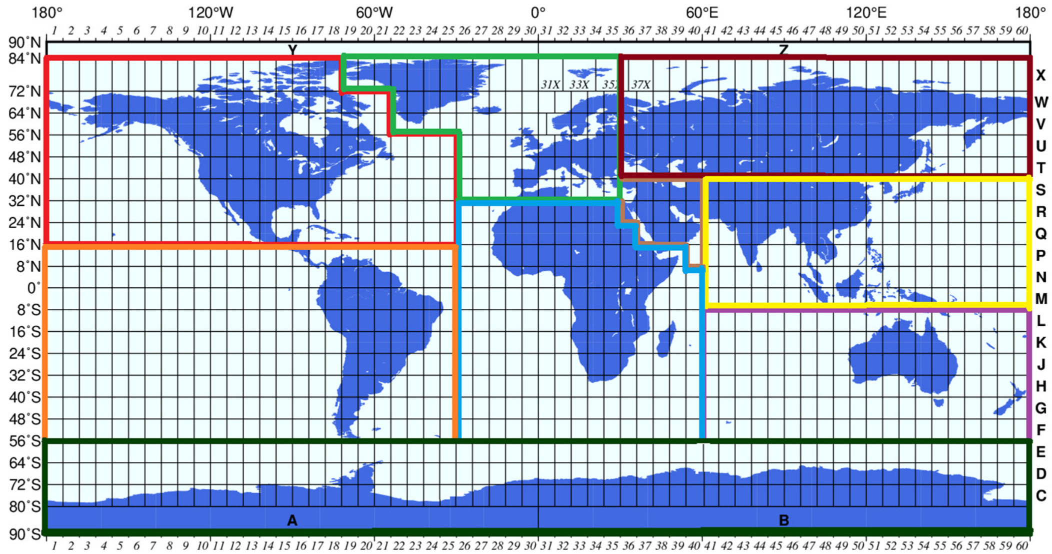

Figure B-2. Delimitation of zones for the economic analysis. 1,140 locations are classified in 9 different regions based on the renewables *CAPEX* reported by the IEA's World Energy Outlook (*WEO*) and *IRENA* **[12,13]**. The return on equity (*ROE*) **[14],** along with the *CAPEX* of renewable systems for each region, are shown in the table below.

Table B-1. Economic data per region.

				Return on equity, *ROE* (%)						*CAPEX* (USD per kW installed)					
				2019			2050			2019	2050	2019	2050	2019	2050
Zone	**Colour**	***WEO* reference**	**Zone**	**Onshore**	**Offshore**	**Deep offshore**	**Onshore**	**Offshore**	**Deep offshore**	**Solar *PV* – Large scale**		**Wind onshore**		**Wind offshore**	
1	Red	United States	North America	10.7	12.2	15.2	10.7	10.7	13.7	1220	543	1560	1413	4260	1519
2	Orange	Brazil	Central and South America	16.6	18.1	21.1	16.6	16.6	19.6	1250	511	1560	1432	4620	1786
3	Green	European Union	Europe	9.6	11.1	14.1	9.6	9.6	12.6	840	400	1560	1392	3800	1561
4	Blue	Africa	Africa	22.1	23.6	26.6	22.1	22.1	25.1	1600	623	1950	1789	4440	1715
5	Dark red	Russia	Russia	16.8	18.3	21.3	16.8	16.8	19.8	2120	813	1630	1495	4800	1865
6	Brown	Middle East	Middle East	16.9	18.4	21.4	16.9	16.9	19.9	1000	394	1800	1626	4580	1754
7	Yellow	India/China/Japan	Asia	12.1	13.6	16.6	12.1	12.1	15.1	1157	502	1513	1392	3413	1404
8	Purple	Australia/Oceania	Oceania	9.1	10.6	13.6	9.1	9.1	12.1	1236	505	1555	1427	4613	1784
9	Dark green	Antarctica	Antarctica	22.1	23.6	26.6	22.1	22.1	25.1	2120	813	1950	1789	4800	1865

Table B-2. Cost data of additional equipment units.

		2019 (today)	2050 (future)	
Equipment	**Sizing based on:**	**USD per size unit**	**USD per size unit**	**Reference**
PEMEL	1 kg/h H_2	98525*	46900*	Section A.1.
Electrical energy storage: Lithium-ion batteries	1 kWh electricity	381	149	[15]
H_2 storage: Type I tanks	1 kg H_2	727	675	[16]

* For 2019, the electricity demand to produce 1 kg of H_2 was set at 56.3 kWh, assuming an average electrolyser efficiency of 59% [17]. For 2050, an electrical energy demand of 46.9 kWh/$kg_{H2,g}$ was assumed, which is equivalent to an average efficiency of the electrolyser of 71% [18].

Table B-3. Plant data.

Parameter	Value
Plant lifetime, t (yr) [19–21]	20
Target production, t/h H_2	30

Appendix C Green H_2 best production locations and cost breakdowns

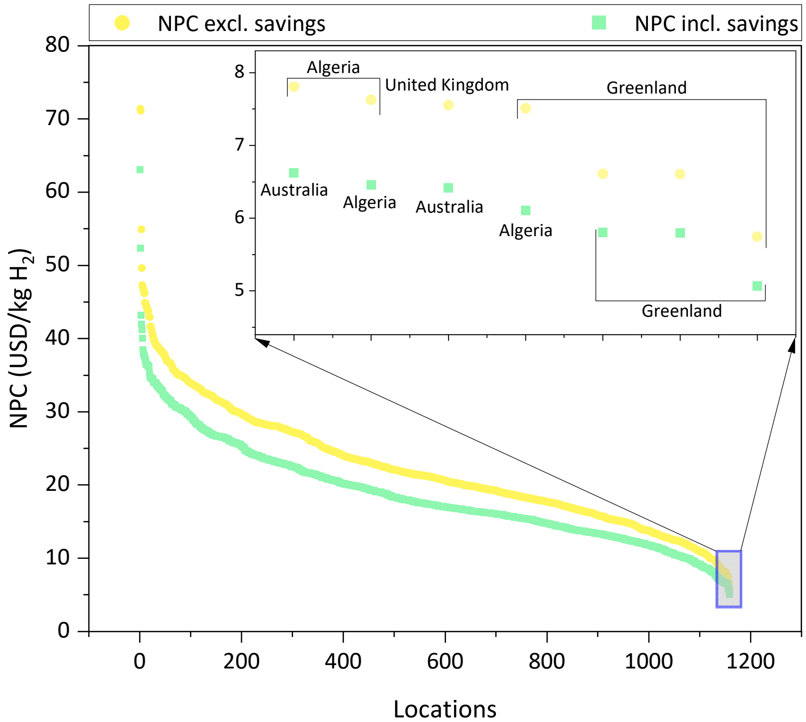

Figure C-1. Green H_2 best production locations "today". The graph presents the cost distribution curves obtained by ordering the *NPC*s from highest to lowest for the scenarios in which the sale of surplus electricity is included (green) and excluded (yellow) in the calculation of the *NPC*. As can be observed, "cheap" H_2 can be produced in very limited locations.

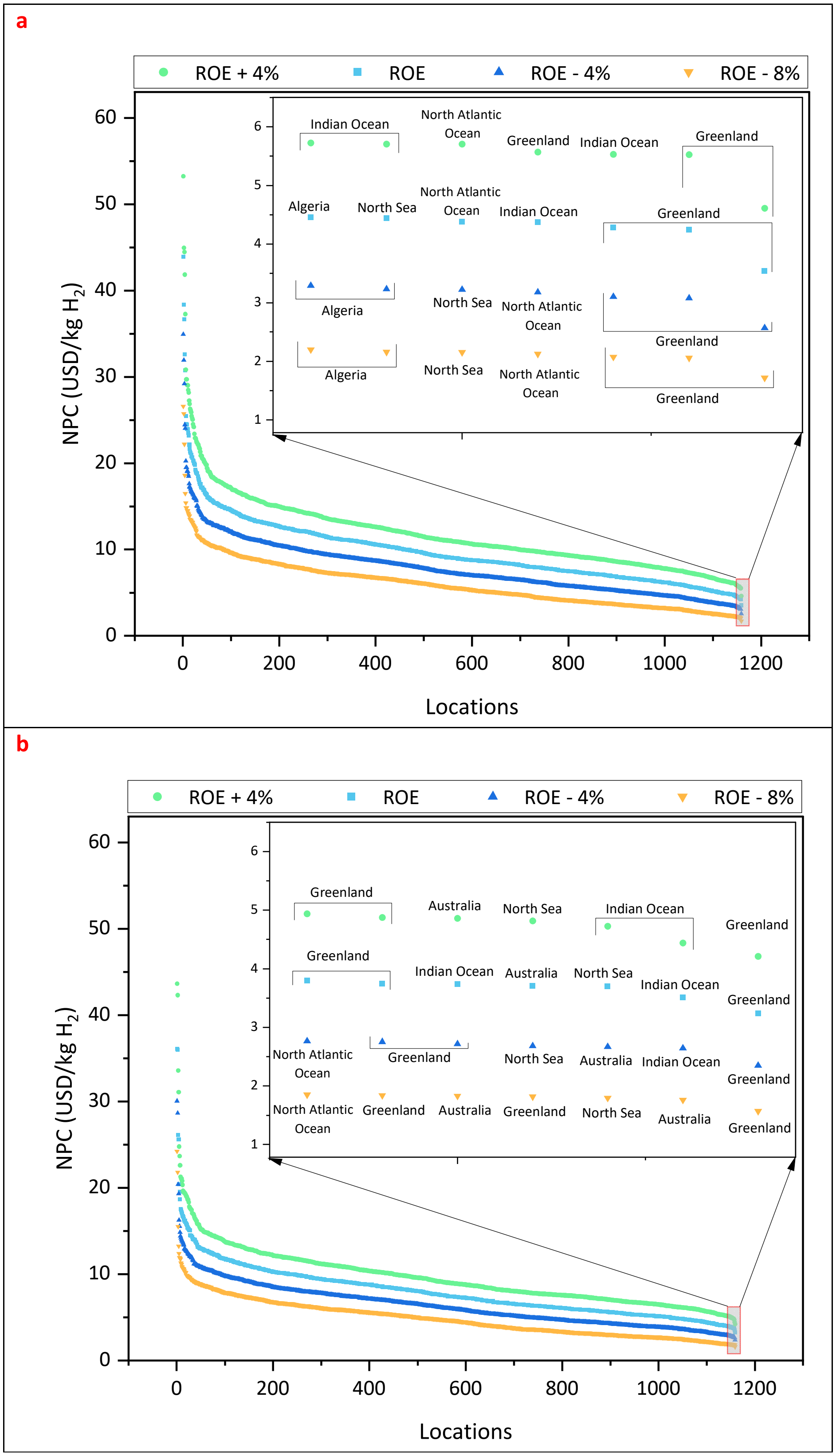

Figure C-2. Green H_2 best production locations "in the future". Subplot *a* and Subplot *b* show the cost distribution curves for the base case scenario (*ROE*) and the scenarios evaluated in the sensitivity analysis, *i.e.*, i) *ROE* - 8%, ii) *ROE* - 4%, and iii) *ROE* + 4%, when revenues from the potential sale of surplus electricity are excluded (*a*) and included (*b*) in the *NPC* of H_2.

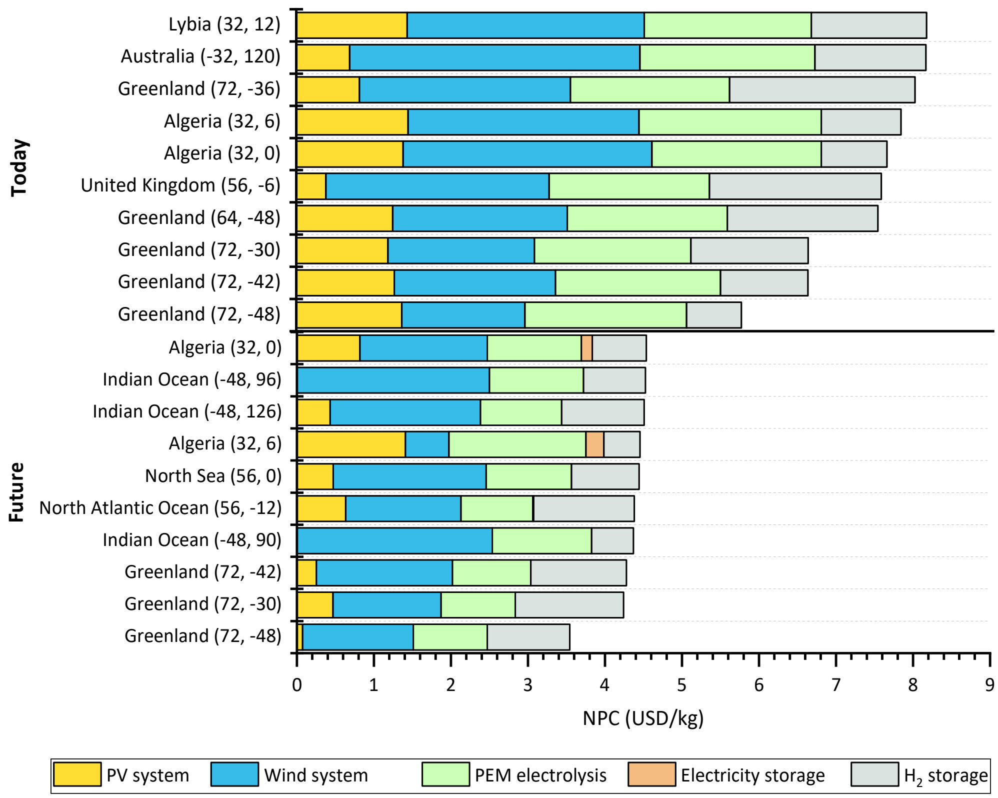

Figure C-3. Breakdown of the *NPC* of green H_2. This figure depicts the breakdown of the *NPC* of H_2 for the ten best production locations (latitude, longitude) resulting from the analysis for "today" and the "future", excluding the revenues from the sale of surplus electricity. In both cases, it is shown that the cost of renewable systems contributes the most to the *NPC* of green H_2, followed by the cost of *PEM* electrolysis and energy storage systems.

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