Supplemental Information

Producing green steel locally in renewables-rich developing regions enhances socioeconomic and climate benefits

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S1. Introduction

The goal of this study is to compare the climate impacts, costs, and local socioeconomic benefits of two possible scenarios: 1) producing green steel in Ceará (Brazil) from green hydrogen produced in Ceará, followed by export to IJmuiden (the Netherlands) and of 2) producing green steel in IJmuiden (the Netherlands) from green hydrogen produced in Ceará. In short, we will call these cases the 'green hydrogen export' case and the 'green steel export' case, respectively (Table S1).

While emissions throughout the process account for climate change impacts, only the socio-economic impacts within the state of Ceará are calculated. Hence, from an environmental life-cycle assessment (LCA) perspective, the system boundaries are cradle-to-gate, covering the climate change impacts of green hydrogen production including for renewable electricity production and battery production, as well as iron ore mining, transport of the iron ore, and green steel production using direct reduction of iron ore (DRI) which uses hydrogen as the reductant, followed by further processing in the electric arc furnace (EAF) to produce steel with specific qualities- including energy and material consumption during these processes. The construction of the electrolyzer and steel production facility is included, as well as transport: either for transporting green steel by ship from Ceará to the Netherlands, or for shipping liquified green hydrogen and iron ore from Brazil to the Netherlands (Table S1). The use phase of the steel is not included in this LCA. The cost for the steel user is based on the levelized cost of steel production (LCOS) and on transport costs (Sections S2.2, S4).

From a socioeconomic perspective, however, only the construction and operational expenditures taking place within Ceará are taken into account. For example, when steel production happens in the Netherlands, the construction and operation of the steel plant are not included in the applied shock, and hence are not directly contributing to economic growth and employment in Ceará (even though there are indirect effects from green hydrogen exports, which are always taken into account).

85 *Table S1- Characteristics of the green hydrogen export case and the green steel export case*

1. Green hydrogen export	2. Green steel export
• Green hydrogen is produced in Ceará, liquified, and shipped to IJmuiden. • Iron ore is mined in the Carajás mine in Brazil, transported by rail to the nearest port and shipped to IJmuiden. • Through DRI-EAF and casting, steel is produced in IJmuiden.	• Green hydrogen is produced in Ceará. • Iron ore is mined in the Carajás mine in Brazil and transported by rail to Port of Pecém. • Through DRI-EAF and casting, steel is produced in the Port of Pecém, and shipped to IJmuiden.

86

87 In order to capture only the effects on the local economy, the shares of each investment component that
88 is spent in Ceará is calculated via local content scenarios. Assumptions for local content scenarios are
89 based on a literature review, a field visit to the Port of Pecém in May 2022, and expert consultations. A
90 detailed analysis of the qualitative data is available in an earlier publication[1] . Key experts were consulted
91 again in September 2024 to revalidate assumptions and confirm their ongoing relevance. Ceará is home
92 to two wind turbine assembly factories: one from Vestas and one from Aeris. The Brazilian electrolyzer
93 manufacturer Hytron has a memorandum of understanding (MoU) with the government of Ceará to
94 construct an electrolyzer assembly plant in the state. However, no companies currently manufacture
95 solar panels, batteries, steel furnaces, or hydrogen liquefaction equipment, nor have any with plans to
96 do so in the coming years been identified. Hence, it is assumed that only wind turbines and electrolyzers
97 could be supplied by local factories in the high local content scenario. More information about the local
98 content scenarios is available in Section S2.3.

99 While the two export scenarios reflect the differences in the connection between the green hydrogen
100 production and its use further in the value chain (i.e., forward linkages), these new economic activities
101 could present different levels of connections with local suppliers backwards in the value chain,
102 depending on whether they source their inputs locally or import them (i.e., backward linkages). To
103 capture the difference in indirect effects resulting from these linkages backwards in the value chain, we
104 use two local content scenarios: plant equipment is assumed to be either locally supplied (high local
105 content scenario) or imported (low local content scenario) (Figure S1).

Backward linkages

		Low	**High**
Forward linkages	**High**	All equipment imported, Green steel exports	Local equipment where possible, Green steel exports
	Low	All equipment imported, Green hydrogen exports	Local equipment where possible, Green hydrogen exports

106 *Figure S1 - Linkages with the local economy in different import and export scenarios*

107 Section S2 explains the assumptions related to the system configuration and technology costs. Section
108 S3 explains the life-cycle assessment methodology conducted to evaluate the climate change impacts.
109 Section S4 explains the input-output modelling methodology used to estimate impacts on output, value
110 added, employment (disaggregated by gender) and household income from salaries.

111 ## S2.   Assumptions

112 This section describes the main assumptions concerning system design, production processes,
113 technologies, and export scenarios that are common to both the life-cycle assessment and the input-
114 output modelling.

115 Figure S2 summarizes the main assumptions regarding the physical quantities from the production
116 required for the new production plants (electricity, electrolysis, liquefaction, green steel). These are
117 explained in detail in Section S2.1. Assumptions on capital and operational costs of these technologies
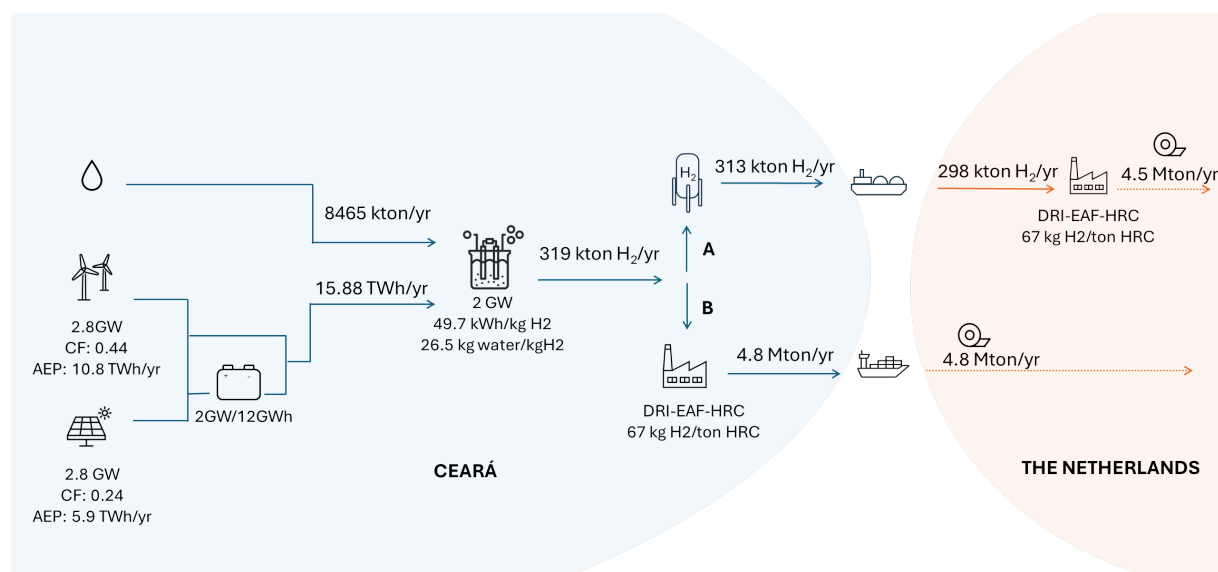118 are described in Section S2.2. Assumptions on local content are described in Section S2.3.

119

120 *Figure S2 - Overview of the main physical input-output quantities and assumptions linking the different value chain*
121 *steps*

S2.1.   Core assumptions on system design and physical input and output quantities

S2.1.1.   Green hydrogen production

124 The study assumes an electrolysis capacity of 2 GW in the Brazilian State of Ceará, in the Port of
125 Pecém. This is based on plans announced in over 20 MoUs signed between investors and the
126 government of Ceará. Individual MoUs announce plans for the short term (i.e., 2025-2030) and for the
127 long term (i.e., 2030 onwards). Announcements for short-term comprise individual plants on the range
128 of 20-500 MW, with a median size of 100 MW. All short-term announcements together add to
129 approximately 2 giga-watts of installed electrolysis capacity. Announcements for the long term (i.e., after
130 2030) are mostly for plants in the giga-watt scale and add up to over 9GW of planned installed capacity[1].
131 We do not take long term announcements into account given uncertainties regarding both the
132 technology progress and the structure of the economy by then.

133 Green hydrogen production is assumed to use alkaline electrolysis cells (AEC), as detailed in Table S2.
134 In the electrolyzer, water is split into hydrogen and oxygen using renewable electricity, with the co-
135 produced oxygen being vented (Figure S3). The water requirement includes both feed water and cooling
136 water, which we assume to be deionized tap water. Additionally, a potassium oxide (KOH) electrolyte is
137 used. The electrolyzer has a lifetime of 20 years[2] We assume two days of maintenance outage and a
138 two percent forced outage rate[3], resulting in a maximum possible operating time of 8538h/year,
139 contingent on the availability of renewable electricity.

140 *Table S2 - Overview of parameters for green hydrogen production using alkaline electrolysis cells*

Process	Operating data per kg H_2	References
Electricity input (kWh)	49.7	[4]
Potassium oxide electrolyte (g)	3.7	[5]
Feed water (kg)	8.9	[6]
Cooling water (5 circulation cycles) (kg)	17.6	[6,7]

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142

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Figure S3 -Representation of an electrolysis plant components. Based on IRENA (2020)
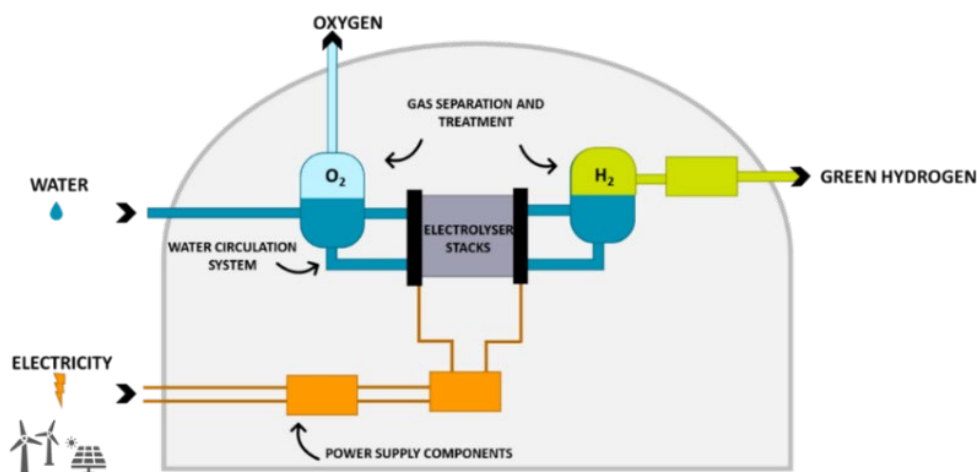
144 *Figure S3 -Representation of an electrolysis plant components. Based on IRENA (2020)*

145 The electrolyzers are assumed to operate independently of the grid, relying exclusively on electricity
146 from solar and wind sources, complemented by a battery system. This is based on the findings from
147 Caiafa et al.[1], which reflect the expectations of stakeholders for the future design of the green hydrogen
148 hub in Ceará. For green hydrogen exports to qualify for green certificates required for imports in the
149 European Union, the renewable electricity generation must be "additional" to what is already connected
150 to the grid[8]. Given the complexities of demonstrating temporal correlation between electrolysis and
151 renewable electricity from the grid, project developers focusing on exports to the EU are opting for
152 isolated systems with dedicated generation from new solar and wind-based power sources[1] These
153 developers prioritize solar and wind systems, complemented by batteries, over other renewable sources
154 such as hydropower. This preference is due to the fact that the North-East of Brazil has a high
155 abundance of solar and wind resources, and, being located on the equator, the relatively limited day-to-
156 day variation in solar irradiance and wind speed, making these two sources largely complementary to
157 each other on a daily basis[1].

158 The local capacity factor for solar photovoltaics (PV) is 24% ($CFsolar$) and 44% for onshore
159 wind ($CFonshore\ wind$) (Table S3). The capacity factors represent the ratio of the actual energy output
160 to the maximum possible energy output that a wind turbine or solar panel could generate. Wind capacity
161 factors based on Ceará Solar and Wind Atlas[9]. Solar capacity factors are calculated using data from the
162 Danish Energy Agency for technology factors and Ceará's GHI as provided in the Ceará Solar and Wind
163 Atlas[3,9]. Assuming solar and wind are fully complementary and consistent, the maximum combined
164 capacity factor ($CFsolar + CFonshorewind$) would be 68%, or 16.3 hours per day.

165 To maximize the operational hours of the electrolyzers, the solar and wind electricity facilities can be
166 oversized and complemented with a battery that allows the electrolyzer to operate with a time lag from
167 when the renewable electricity is produced. We assume the use of a mainstream lithium nickel
168 manganese cobalt oxide battery, which stores enough electricity to run the electrolyzer for 6 hours.
169 Beyond this capacity, a battery is no longer a cost-effective storage solution[10]. The resulting nameplate
170 capacity of the battery is 12 GWh given the 2GW of electrolysis capacity. By effectively adding 6 hours
171 of operation per day, the operational capacity factor of the electrolyzer ($CFelectrolyser$) can reach up to
172 93%, or 22.3 hours per day. Considering 8538 as the maximum yearly operating hours (excluding
173 planned and forced outages for maintenance), this would result in 7940 hours of yearly operating time.

174 The same assumptions regarding solar and wind capacity factors and battery capacity are applied to all
175 export and local content scenarios.

176 *Table S3 - Renewable energy capacity factors in Ceará.*

Renewable Energy Technology	Conditions	TechPotential	Capacity factor
Solar PV	Global horizontal irradiance (GHI) of 2075 kWh/m²/year	642 GW	24%
Onshore wind	Wind speed >7m/s at 150m height	94 GW	44%

177 Based on the assumptions detailed above, it is possible to calculate the annual hydrogen production
178 rate (M_{H_2}, in kt H$_2$/year; Equation 1), and the total hydrogen production over the lifetime of the
179 electrolyzer (Q_{H_2}, in kt H$_2$; Equation 2).

$$M_{H_2} = \frac{cap_{electrolyser} \cdot CF_{electrolyser} \cdot hours/year}{P_{electrolyser}} \qquad \text{Equation 1}$$

180

181 For an electrolyzer capacity ($cap_{electrolyser}$) of 2 GW, an operational capacity factor of the electrolyzer
182 ($CF electrolyser$) of 93%, 7940 hours of yearly operating time, and an electrolyzer electricity requirement
183 ($P_{electrolyser}$) of 49.7 kWh per kg H$_2$, M_{H_2} is calculated to be 319 kt H$_2$/year.

$$Q_{H_2} = M_{H_2} \cdot lifetime_{electrolyser} \qquad \text{Equation 2}$$

184

185 Based on a lifetime of the electrolyzer ($lifetime_{electrolyser}$) of 20 years [2], Q_{H_2} is calculated to be 6391
186 kton H$_2$.

S2.1.2. Electricity production

188 The required installed capacity of the renewable energy technology ($cap_{facility,ren}$ in GW), where ren is
189 solar PV and onshore wind, is determined by Equation 3, accounting for electricity losses from using a
190 battery.

Equation 3

$$cap_{facility,ren} = cap_{electrolyser} \cdot \frac{CF_{onshore\,wind} + CF_{solar} + f_{battery}}{CF_{onshore\,wind} + CF_{solar}} \cdot (1 + f_{battery} \cdot (\frac{1}{e_{battery}} - 1))$$

191

192 Where $cap_{electrolyser}$ is the electrolyzer capacity (GW), $CF solar$ and $CF onshore\,wind$ the capacity
193 factors of solar and wind solar power, $e_{battery}$ the roundtrip efficiency of the battery, and $f_{battery}$ the
194 share of electricity passing through the battery before being used in the electrolyzer. We use a roundtrip
195 efficiency of 90% for a lithium nickel manganese cobalt oxide battery[5,11] and assume that up to 25% of
196 electricity passes through the battery, consistent with a battery capacity of 6 hours.

197 Based on Equation 3, we find that to generate enough electricity to power the battery and compensate
198 for battery losses, the renewable energy capacity needs to be increased by 41% compared to the
199 electrolyzer capacity. Therefore, for an electrolyzer capacity of 2 GW, a solar PV facility of 2.8 GW and
200 an onshore wind facility of 2.8 GW are required.

S2.1.3. Hydrogen liquefaction and shipping

202 In the green hydrogen export case, hydrogen is transported in its liquified form, requiring cooling to -253
203 °C. The life-cycle inventory for hydrogen liquefaction and shipping is based on our previous study on
204 green hydrogen production and transport[12]. Since a continuous source of electricity is needed for
205 hydrogen liquefaction, grid electricity is used for this.

206 For shipping, a 160,000 m^3 liquid hydrogen tanker is assumed[13]. With a volumetric density of liquid
207 hydrogen of 71.1 kg per m^3, each tanker can carry 11.376 kton of hydrogen, equivalent to approximately
208 13 days of production. The distance between the Port of Pecém and IJmuiden is 7500 km, and at a
209 shipping speed of 16 knots[14], the journey would take 10.5 days.

210 Storing a liquid energy carrier under cryogenic conditions results in boil-off gas, which can be
211 recirculated and reliquefied during storage on land but leads to mass loss during shipping and
212 loading/unloading. The mass loss of 0.3% per day from boil-off gas during shipping[15] is assumed to
213 contribute to global warming, based on a 100-year global warming potential of 11.6 kgCO$_2$-eq/kg H$_2$[16].

214 The tanker is expected to be fueled by heavy fuel oil in the near future (2025), pending technological
215 developments that would allow boil-off gas to be used as shipping fuel[14]. Electricity for liquefaction, re-
216 liquefaction of hydrogen during land storage, and loading liquid hydrogen into the tanker is assumed to

217 be supplied by the North-East Brazilian grid mix. Electricity use for unloading liquid hydrogen is assumed
218 to be supplied by the Dutch grid mix.

S2.1.4. Iron ore mining and transport

220 We assume iron ore is mined in the Carajás mine, the largest iron ore mine in the world, located in
221 northern Brazil. This assumption applies to both the green hydrogen export case and green steel export
222 case, given the high quality of the iron ore and the fact that the Netherlands already imports iron ore
223 from Brazil[17].

224 The location of iron ore pelletizing depends on both the export scenario and the local content scenario.
225 In the green hydrogen export scenario, all iron ore pelletizing is assumed to occur near the Carajás
226 mine, with the pellets transported to IJmuiden by rail and ship, regardless of the local content
227 configuration. In the green steel export scenario, iron ore is either fully processed near the Carajás mine
228 and transported by rail to Pecém (low local content) or approximately half of the iron ore is transported
229 to be processed locally in Ceará, with the remaining pellets sourced from Carajás (high local content).

230 In both scenarios, transport within Brazil is done by rail, using a conventional diesel train[18]. For the
231 green hydrogen export case, the transport distance by rail is approximately 1000 km to the port of Ponta
232 de Madeira[18], from where it is shipped to IJmuiden by a dry bulk carrier, covering an additional distance
233 of 7600 km. In the green steel export case, steel production takes place in the Port of Pecém, to which
234 transport is fully undertaken by rail, covering a distance of approximately 2000 km.

235 In the sensitivity analysis we evaluate a scenario where instead of a diesel train, an electric train powered
236 by the North-East Brazil grid mix is used.

S2.1.5. Steel production and transport

238 Direct reduction of iron ore (DRI) is carried out using hydrogen as the reductant. In the DRI shaft furnace,
239 sponge iron is produced and subsequently processed in the electric arc furnace (EAF) to achieve
240 specific steel qualities[19] (Figure S4). In the base case, hydrogen is used for iron ore reduction in the
241 shaft furnace, while natural gas is used for hydrogen pre-heating, EAF heating and ladle heating (H2-
242 NG-DRI;Table S4). In the sensitivity analysis, we evaluate a scenario where hydrogen is used for both
243 iron ore reduction and heating, replacing natural gas from the initial configuration (H2-DRI; Table S4).

244 The electricity requirements for the EAF are supplied by the North-East Brazilian grid mix in the green
245 steel export case, and by the Dutch grid mix in the green hydrogen export case.

246 Assuming all produced hydrogen is used, 4,768,912 t/year of steel can be produced in Ceará,
247 considering a hydrogen requirement of 67kg of hydrogen per ton of Hot Rolled Coil (HRC) and an annual
248 production of 319 kton H2/year. A smaller amount of steel can be produced for the same annual green
249 hydrogen production when green hydrogen is liquefied and transported by ship (4.5Mt/year, see Figure
250 S4 and Section S3.4) due to conversion and transport losses.

251 *Table S4 - Inventory for the production of 1 ton of steel through DRI-EAF, casting and hot rolling for the configuration*
252 *using hydrogen only for reduction, and natural gas for heating (H2-NG-DRI), or using hydrogen for reduction and*
253 *heating (H2-DRI). Based on Rosner et al (2023)*

	H2-NG-DRI	H2-DRI
Process	**Input per ton of steel**	**Input per ton of steel**
Iron ore pellets (ton)	1.63	1.63
Hydrogen (kg)	67	76
Natural gas (GJ)	1.06	0
Electricity (kWh)	550	550
Carbon (kg)	34	34
Lime (kg)	51	51
Raw water withdrawal(ton)	1.2	1.2
Anode (kg)	3.5	3.5
Refractory lining (kg)	15.5	15.5
Process	**Output per ton of steel**	**Output per ton of steel**
Slag (ton)	0.17	0.17
Surface water discharge (ton)	0.44	0.44
Direct CO_2 emissions (ton)	0.16	0.10

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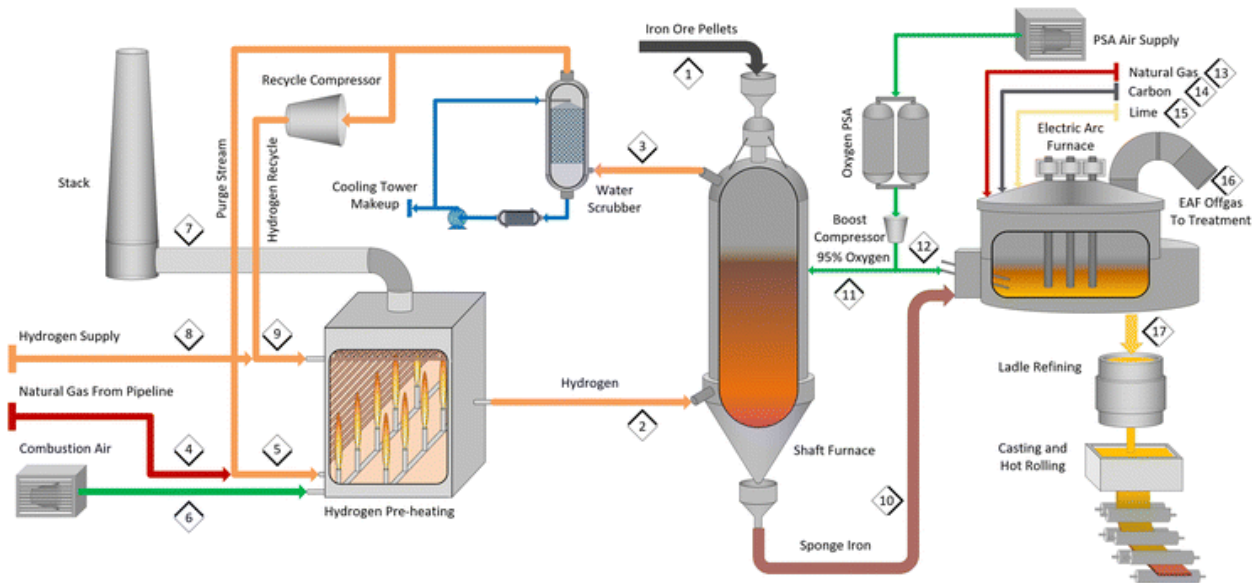
255

256 *Figure S4 - Flowsheet of the integrated hydrogen-based DRI steel mill, using hydrogen for iron ore reduction in the*
257 *shaft furnace, and using natural gas for hydrogen pre-heating, EAF heating and ladle heating (H2-NG-DRI) (Rosner*
258 *et al., 2023a).*

259 In the sensitivity analysis, we assess the scenario in which sponge iron is produced in Ceará and
260 shipped to IJmuiden, for steel production in the EAF. Inputs from the base case (H2-NG-DRI) for DRI-
261 EAF steelmaking are divided between DRI in Ceará and EAF in IJmuiden, based on the flowsheets in
262 Rosner et al[19] (Table S5).

263 *Table S5 - Inventory for the production of 1 ton of steel in the H2-NG-DRI configuration, based on Rosner et al*
264 *(2023) for the sponge iron export scenario in the sensitivity analysis. The last two columns indicate the share of*
265 *inputs used in the DRI phase producing sponge iron in Ceará, and in the EAF phase producing steel in IJmuiden.*

Process	H_2-NG-DRI Input per ton of steel	DRI in Ceará Input per ton of steel (% of H_2-NG-DRI total)	EAF in IJmuiden Input per ton of steel (% of H_2-NG-DRI total)
Iron ore pellets (ton)	1.63	100	0
Hydrogen (kg)	67	100	0
Natural gas (GJ)	1.06	88	12
Electricity (kWh)	550	17	83
Carbon (kg)	34	0	100
Lime (kg)	51	0	100
Raw water withdrawal(ton)	1.2	100	0
Anode (kg)	3.5	0	100
Refractory lining (kg)	15.5	0	100
Process	**Output per ton of steel**	**Output per ton of steel (% of H_2-NG-DRI total)**	**Output per ton of steel (%of H_2-NG-DRI total)**
Slag (ton)	0.17	0	100
Surface water discharge (ton)	0.44	100	0
Direct CO_2 emissions (ton)	0.16	22	78

266 ## S2.2.   Cost assumptions

267 Cost assumptions for electricity and green hydrogen in this study are based on the most recent studies
268 found, which usually account for the period 2018-2021. The most recent sub-national supply and use
269 tables (SUTs) available for Ceará were published by the Brazilian Institute of Geography and Statistics
270 (IBGE) in 2022 and refer to the economic year of 2018[20] (see Section S4 for more details about the
271 tables). The table is the first published by the institute for the sub-national level and has a high sectoral
272 aggregation, making any effort to update the table virtually impossible. Since the cost data covers a
273 similar period of the SUTs and this was a period of relatively low inflation, no price correction was carried
274 out to arrive to 2018 prices. The only occasion where cost assumptions were deflated was for steel

275 production costs, since the main reference used is from 2023[19] and the authors report inflating cost
276 assumptions to match 2022 prices due to the high inflation period between 2021-2022.

277 Costs are not available by origin of equipment. This implies that this study is unable to differentiate
278 between costs in a high and in a low content scenario for equipment sourcing.

279 *S2.2.1.   Green hydrogen production*

280 Cost assumptions for hydrogen production are as following. Total installation costs include direct,
281 indirect, and owner costs. Direct costs cover the investment required for purchasing the electrolyzer
282 system and constructing the facility[21,22]. These costs include the electrolyzer stack as well as the balance
283 of plant components such as the drier, cooling system, de-oxygenation unit, water de-ionization
284 equipment, and the power supply[21,23]. Some estimates for direct costs also include installation on-site,
285 interconnecting piping and other materials, and services from contractors and suppliers[22]. Indirect costs
286 involve expenses related to engineering, project management, construction supervision, and
287 commissioning. Owner costs cover project management by the owner, land leases during construction,
288 insurance, grid fees, and electricity consumption. In many studies, contingency costs are added to cover
289 risks due to uncertainties[22,24]. Estimates for costs can be found in the Table S6 below.

290 *Table S6 - Comparison of low and high estimates for electrolysis systems CAPEX costs*

Study	Direct costs		Indirect costs		Owner costs	
	Definition	Value	Definition	Value	Definition	Value
International Renewable Energy (IRENA)[21]	Electrolyzer system	500-1000 USD/kW	n.a	n.a.	n.a.	n.a
United Kingdom BE&IS Department [23]	Electrolyzer system and civil works	720-960 USD/kW	n.a	n.a	n.a	n.a
Danish Energy Agency (DEA)[3]	Electrolyzer system plus 10% installation costs	440-880 USD/kW	n.a	n.a	n.a	n.a
Institute for Sustainable Process Technology (ISPT)[22]	Electrolyzer system plus 3% of civil works	600-1160 USD/kW	Expenses for engineering, project management, construction supervision and management, and commissioning costs (no cost break-down) (90-218 USD/kw) and Contingency (184 USD/kw)	90-218 USD/kW	Owner project management, electricity consumption and land lease during construction, as well as insurances and grid fees (no cost break-down)	36-70 USD/kW
Lazard[25]	Electrolyzer system	310-920 USD/kW	n.a	n.a	n.a	n.a
National Renewable Energy Laboratory (NREL)[24]	Electrolyzer system (460 USD/kW) plus 9.3 USD/kW for	470 USD/kW	Up-front permitting costs (70USD/kW), Engineering	116-186 USD/kW	5 acres of land for 131MW electrolysis at USD	1.90 USD/kW

construction (site preparation) (2%)	and design (46USD/kW) Contingency (70USD/kW)	50,000.00 the acre

Note: Based on conversion of 1GBP = 1.2 USD and 1EUR = 1.10USD.

In this study, an average value of 736 USD/kW is derived from Table S6, with 714 USD/kW allocated to system costs and 22 USD/kW (or 3% of direct costs) attributed to construction. A value of 168 USD/kW is assumed for indirect and owner costs. While the ISPT[22] study estimates 23% for contingency costs (184 USD/kW), the NREL[24] study presents a lower estimate (70 USD/kW), likely because the NREL model is based on a 131MW plant, whereas the ISPT study looks at a much larger 1GW plant, which involves greater uncertainties due to the absence of operational giga-scale plants. Given that this study considers the first large-scale green hydrogen hub in Brazil, which carries significant first-of-a-kind project risks but focuses on projects in the 100-500MW range, an average contingency cost of 120 USD/kW is used. This leads to a total installation cost of 1023 USD/kW.

Different assumptions for electrolysis plant OPEX were found in the literature (see Table S7). We assume fixed operational expenditures to consist of insurance and direct labor. The NREL (2018) H2A model assumes 2% of initial capital expenditures (CAPEX) to go to taxes and insurances and Lazard[25] assumes 1% of insurance, so our assumption is 1% of initial CAPEX, or 10.24 USD/kW/year. Assumptions for direct labor in the electrolysis plant are based on expert consultations[1]. Experts indicated that a 20-100 MW electrolysis plant in Ceará would employ between 5-10 people working full-time (full-time equivalent (FTE)) in the operation phase. This would lead to an employment factor of 0.25-0.5 FTE/MW for a 20 MW plant and 0.05-0.1 FTE/MW for a 100MW plant. The H2A model from NREL[24] assumes 10 FTE for a 131 MW plant, hence 0.076 FTE/MW. Therefore, we assume a value of 0.07 FTE/MW of electrolysis capacity. The average salary is taken from salary data from the Brazilian Ministry of Employment[26] for workers in the energy sector in Ceará, and is 35,510 USD/year for 1 FTE, leading to direct labor costs of 2.485 USD/kW/year. Annuitized stack replacements are assumed to be 2% of initial CAPEX, that is, 20.48 USD/kW/year.

Table S7 - Operational expenditures for green hydrogen production found in the literature review

Study	OPEX definition
UK BE&IS[23]	Variable OPEX as annuitized stack replacement costs, as well as costs for water and electricity inputs. Fixed OPEX including direct labor, administration/general overheads, insurance/local taxes, but excluding cost of hydrogen compression equipment.
Lazard[25]	OPEX includes water costs, electricity costs, warranty and insurance (1% of initial CAPEX/year) and "other O&M"(1.5% of initial Capex/year).
Gallardo et al[27]	OPEX costs including electricity cost and O&M cost (2% of initial CAPEX/ year)
IRENA[28]	Includes OPEX as 2% of initial CAPEX/year. No definition of OPEX cost items provided.
Eichman et al[29]	Estimates fixed O&M at 42$/kW/yr. In addition, estimates storage costs 623–1000 $/kg of hydrogen. Also add an installation cost multiplier of 1.2.
NREL[24]	NREL hydrogen production model (H2A) for central electrolysis (version 3.2018) provides OPEX costs for a ~110 MW PEM electrolysis plant. They estimate OPEX fixed at 5.5% of initial CAPEX, that can be disaggregated by: 2% for taxes and insurances, 2% for material costs for maintenance and repairs,1.5% for labor cost and General& Administrative (G&A) costs, assuming 10FTE employees with an 50$ hourly wage and a 20% rate for G&A over labor costs. They also recognize cost components for which they do not have values, for instance for licensing, permits and fees. In addition to these fixed inputs they include energy and water costs in the OPEX.
DEA[3]	Includes only Fixed O&M costs as 2% of CAPEX.

Variable costs are calculated assuming the yearly production of hydrogen (see Section S2.1). For an annual production of 319.5kton of hydrogen, 8467 kton/year of water would be required. We assume water cost of 0.002 USD/kg of water based on Lazard[25]. This leads to water costs of 8.47 USD/year per kilo-watt of electrolysis capacity. Electricity costs are based on the electricity consumption of 15.88

319   TWh/year and the levelized cost of electricity according to the electricity production cost assumptions,
320   calculated to be 64.17 USD/MWh, as will be described in Section S2.2.2).

321   The sales of price of green hydrogen is assumed to be the levelized cost of hydrogen (LCOH), since
322   this is the minimum sales price required for a zero profit condition. In the green hydrogen exports case,
323   the LCOH includes liquefaction and storage costs in Pecém, while in the green steel exports case the
324   LCOH includes the investment and operational costs of the electrolysis plant only. A weighted average
325   cost of capital of 10% is assumed, as in the report from IRENA[30]. The LCOH obtained in this study is
326   4.17 USD/kgH$_2$, excluding any liquefaction, storage, or shipping costs. This somewhat higher LCOH
327   when compared to IRENA's estimates can be explained by the need to oversize the renewable energy
328   facilities and to add a battery considering the assumption of dedicated generation (see Section S4.1).
329   When liquefaction, storage, and ship loading costs are included (see Section S2.2.3), the sales price of
330   hydrogen becomes 6.65 USD/kgH$_2$.

S2.2.2.   Electricity production

332   Total installation costs of 849 USD/kW for solar photovoltaics and 1237 USD/kW for onshore wind are
333   assumed in this study, which can be translated into 1189USD and 1732USD per kW of electrolysis
334   installed capacity(kWH$_2$), respectively, given a scaling factor of 1.4. IRENA[31] has total installed costs for
335   onshore wind and solar photovoltaics in Brazil for the year of 2021. Both the EIM-ES[32] and NREL JEDI[33]
336   models were also consulted. Given that IRENA[31] offers more recent and country-specific data, this study
337   primarily uses the IRENA figures when available, while incorporating EIM-ES estimates for land and
338   contingency costs, missing in the IRENA[31] data. For onshore wind, only total installation costs are
339   available in the IRENA report[31]. Costs by component are hence calculated by taking the cost
340   disaggregation from previous studies[32–34] and the country-specific total installed costs for Brazil from
341   IRENA[31]. IRENA reports total installed costs for onshore wind in Brazil to be 1150 USD/kW in 2021. To
342   this, we add 49 USD/kW for contingency and 49 USD/kW for transport of the turbines, as reported by
343   Fearnehough & Skribbe[32]. The disaggregation of CAPEX by cost item is available on Table S8.

344   Regarding the operational expenditures, we assume total operation and maintenance (O&M) costs for
345   onshore wind of 55 USD/kW/year. This includes 18 USD/kW/year for maintenance and 12 USD/kW/year
346   for operation, as well as 2.5 USD/kW/year for land lease, as reported by Fearnehough and Skribbe[32].
347   Regarding employment factors, the literature has reported values between 0.1-10.7 FTE/MW of installed
348   capacity, with a median of 0.64 FTE/MW and an average of 2.13 FTE/MW[35–39]. We take the median
349   value for this study, which leads to an annual direct labor expenditure of 23 USD/kW/year. These costs
350   are in line with the IRENA[31] study that reports a total O&M cost of 49-53 USD/kW/year for onshore wind
351   in Denmark and Germany and with the work from Vasconcellos & Caiado Couto[34] that assume a total of
352   45 USD/kW/year for onshore wind in Brazil, but do not include labor costs.

353   For Solar PV, we assume 60 USD/kW/year for total O&M expenditures. The EIM-ES reports 9.5
354   USD/kW/year for operation and 11.5 USD/kW/year for maintenance, comprising materials only[32].
355   IRENA[31] does not provide O&M data for Solar PV. Regarding employment factors, the literature reports
356   values between 0.12-4.8 FTE/MW, with a median of 1.1 FTE/MW and an average of 1.4 FTE/MW[35–38].
357   Assuming the median value of 1.1 FTE/MW and salaries for the energy sector in Ceará, salary
358   expenditures for solar PV are assumed to be 39 USD/kW/year.

359   For the battery system, we assume 1410 USD/kW and 35 USD/kW/year for installation and operational
360   costs, respectively, for a 1kW-6kWh battery[40].

361   *Table S8 - Cost assumptions for electricity production*

Technology	CAPEX item	USD/kW	OPEX item	USD/kW/year
Solar PV	Modules	369	Maintenance	11.5
	Inverters	36	Operation	9.5
	BoS hardware	129	Direct labor	39
	Installation	155		
	Design and engineering	9		
	Other (PR, permitting, customer)	51		
	Contingency and fees	97		
	Land	3		

	Total CAPEX	849	Total OPEX	60
Onshore Wind	Nacelle	444	Maintenance	18
	Blades	180	Operation	12
	Tower	155	Land lease	2.5
	Construction (Civil works + Installation)	189	Direct labor	23
	Electrical balance of plants	133		
	Project planning and management	38		
	Contingency and finance	49		
	Transport	49		
	Total CAPEX	1237	Total OPEX	55
Battery	Battery system (1kW/6kWh)	1410	Maintenance	35
	Total CAPEX	1410	Total OPEX	35

362

363 Hence, for an scaling factor of 1.4 and a battery system of 6h storage duration, annual O&M costs for
364 the electricity supply of the electrolysis plant would be 196 USD/kWH$_2$/year: 77.5 USD/kWH$_2$/year
365 coming from the onshore wind farm, 84 USD/kWH$_2$/year from the solar PV plant, and 35 USD/ kWH2
366 from the battery maintenance. Assuming an real weighted average cost of capital (WACC) of 6%[30], the
367 calculated levelized cost of electricity (LCOE) for the entire system (including energy storage) is 64.17
368 USD/MWh.

369 ### S2.2.3. Hydrogen liquefaction and shipping

370 Capital costs for liquefaction and storage are assumed to be USD 2000/kWH$_2$ and USD 87/kWH$_2$,
371 respectively, based on a liquefaction unit of 50tH$_2$/day[41] and costs of USD 15/kgH2[41] for a storage
372 capacity greater than 100 000m3. Capital costs for liquefaction plants[41].

373 *Table S9 - Cost assumptions hydrogen liquefaction and storage*

CAPEX item	USD/kWH2	OPEX item	USD/kgH2/year
Liquefaction plant	2000	Electricity	0.977
Storage	87	Direct labor	0.028
Total	2087		1.004

374

375 Operational costs are assumed to be a total of USD 1.004/year per kilogram of hydrogen (kgH2)
376 produced, the equivalent of USD 160/year per kW of installed capacity of hydrogen (kWH2) given our
377 hydrogen production assumptions. This comprises of USD 156/year of electricity costs and USD
378 4.43/year for direct labor costs. This reflects an electricity cost of USD 0.977/kgH2, based on the
379 calculated total electricity requirement of 12.5213 kWh/kgH2, including re-liquefaction of BOG during
380 storage, and electricity prices for industrial consumers in Brazil[42] of USD 78/MWh. Regarding direct
381 employment, we assume a total of 30 full-time equivalent direct jobs for a 50t/d liquefaction capacity,
382 based on a recently inaugurated Air Liquide liquefaction plant in Nevada, United States, with 30t/d
383 capacity and 25 FTE expected[43] (i.e. we assume employment factors do not increase linearly with scale,
384 as with most technologies in the green hydrogen value chain[1]). Considering 18 liquefaction units would
385 be required, this leads to a total of 525 FTE directly employed. Assuming the average salary for the
386 industrial gases sector in Ceará (USD 16882/FTE/year[26]), this leads to salary expenditures of USD
387 0.028 /kgH2/year. The levelized cost of liquefaction and storage (LCOLS) is then calculated assuming
388 a similar WACC as for the green hydrogen electrolysis (i.e., 10%). We find a LCOLS of 2.49 USD, which
389 is in the mid-range of the costs reported by IRENA[41] given the relatively small scale of the plant.

390 Regarding the loading of the liquid hydrogen into ships, we assume the existing LNG terminal in the Port
391 of Pecém would be repurposed for hydrogen terminalling, since activities around the Ports for the
392 international trade of hydrogen would resemble those of liquified natural gas (LNG)[41]. Hence, we base
393 the cost assumptions for liquid hydrogen on the costs for LNG. Fluxys, the Belgian transmission system
394 operator (TSO) that also operates in Brazil, reports a price of 1.17€/MWh of LNG loaded. If we assume
395 similar prices for green hydrogen, this would lead to a 0.04588 USD/kgH2.

396 The building of new ships and the sea transport of hydrogen are not taken into account in the economic
397 impact analysis since it is assumed that these activities would be carried out by firms outside of Ceará.

398 The sales price of exported liquid hydrogen at the Ceará's border (i.e., FOB) is calculated to be USD
399 6.7/kgH2, and includes liquefaction, storage, and terminalling (ship loading) at the Port of Pecém
400 (Equation 4).

<div align="right">*Equation 4*</div>

$$H2price_{FOB} = LCOH + LCOLS + H2cost_{terminalling}$$

401 This refers to USD 4.17/kgH2 from production, 2.49 USD/kgH2 from liquefaction and storage, and USD
402 0.05/kgH2 from ship loading.

S2.2.4.   Iron ore mining and transport

404 Iron mining is considered to take place outside of Ceará and is an existing sector, so no investment and
405 operational expenditures are exogenously specified in this study for this economic activity. We simply
406 assume that the new steel plant would be purchasing iron ore pellets from existing producers at current
407 market prices and transport margins, as explained below in Section S2.3, which will lead to economic
408 impacts in the sector due to increased demand. The location of iron ore pelletizing depends on both the
409 export scenario and the local content scenario. In the green hydrogen export scenario, all iron ore
410 pelletizing is assumed to occur near the Carajás mine, with the pellets transported to IJmuiden by rail
411 and ship, regardless of the local content configuration. In the green steel export scenario, iron ore is
412 either fully processed near the Carajás mine and transported by rail to Pecém (low local content) or
413 approximately half of the iron ore is transported to be processed locally in Ceará, with the remaining
414 pellets sourced from Carajás (high local content) (Section S2.3).

S2.2.5.   Steel production and transport

416 Capital and operational expenditures are based on the same study used to derive the life-cycle inventory
417 to ensure consistency of the production technology[19], with some adjustments. Capital expenditures are
418 deflated where needed to reflect US dollars in the year of 2018, since the authors report inflating prices
419 to match 2022 US dollars. Prices for raw material inputs are adjusted based on additional sources
420 reporting prices for 2018 as needed[44,45].

421 In the green steel exports scenario, the steel plant is located in the same industrial complex as the
422 electrolysis plant, avoiding the need for the liquefaction and shipping steps. As they would be located
423 spatially together, transport costs are considered to be minimal and are hence left out of the analysis
424 (since transport within the Port complex in IJmuiden is also not taken into account). It is assumed that
425 the local sales price of hydrogen within the industrial complex at the Port of Pecém would be equal to
426 the levelized cost of hydrogen (LCOH).

<div align="right">*Equation 5*</div>

$$H2price_{PECÉM} = LCOH$$

427 Moreover, the green steel exports scenario, prices for electricity[42] and natural gas[46] are assumed to be
428 the prices for industrial consumers in Brazil in the year of 2018. Labor costs are calculated taking the
429 Rosner et al study[19] employment factors and adjusting salaries to reflect the average salaries in the Iron
430 and Steel sector in Ceará in 2018, based on data from the Brazilian Ministry of Employment[26].

431 When steel is produced in Ceará, we consider an additional transport cost of steel of 5 USD/t[47] to bring
432 the steel to the port in IJmuiden.

433 In the green steel exports scenario, the export price of steel is assumed to be the levelized cost of steel
434 production (LCOS).

435 In the green hydrogen export scenario, the steel plant in IJmuiden would pay a price for green hydrogen
436 that would be equivalent to the FOB green hydrogen price, plus the transport by ship to IJmuiden and
437 regasification costs at destination. It is assumed that costs associated with the loss of hydrogen due to
438 boil-off gas during transportation are already priced into shipping costs from techno-economic studies.
439 Transport within the Port complex in IJmuiden is also not taken into account. Costs for shipping green
440 hydrogen from Pecém to IJmuiden and for regasification of liquefied hydrogen in IJmuiden are based
441 on the average estimates by IRENA[41], with shipping costs being adjusted to the distance between
442 Pecém and IJmuiden (approximately 7500 km). The green hydrogen price in IJmuiden adds up to
443 9.18USD/kgH2, consisting of the 6.7 USD/kgH2 FOB price, plus 1.73 USD/kgH2 of shipping and 0.75
444 USD/kgH2 of regasification.

445 Additionally, the prices for electricity[48] and natural gas[49] are assumed to be the prices for industrial
446 consumers in the Netherlands in the year of 2018. These prices are taken from EUROSTAT, using
447 average exchange rate of 1 EUR = 1.1810 USD for 2019[50]. Labor costs are also calculated taking the
448 Rosner et al study[19] employment factors and adjusting salaries to reflect the average salaries paid by
449 Tata Steel IJmuiden[45], the single largest steel producer in the Netherlands.

Equation 6

$$H2price_{IJMUIDEN} = H2price_{FOB} + H2cost_{shipping} + H2cost_{regasification}$$

450 The year of 2018 is chosen to match the input-output tables for Ceará. For the cost analysis, a sensitivity
451 analysis is carried out to also assess the difference in costs after 2022, given the energy crisis in Europe.

452 The CAPEX and OPEX are summarized in Table S10, and Table S11, respectively.

453 Finally, we assume the same WACC as liquefaction and storage (i.e., 10%). While Rosner et al.[19] use a
454 much lower rate (5%), their rate is based exclusively on debt, while Damodaran[51] [47]and the IEA[52] show
455 capital costs for the steel industry as being much higher, around 6-9%. Additionally, Damodaran[51]
456 estimates for capital costs for the chemical industry (to which hydrogen and liquefaction belong) are
457 around 7.5%, which is relatively similar than the estimates for steel (6.85%). Assuming a 10% WACC
458 for "green steel" allows incorporating a higher risk than for traditional steel given the low maturity of the
459 technology and market while ensuring it has a similar rate as for the other "green" immature industries.
460 A similar rate avoids that results on the share of value added going to operating surplus are different
461 solely due to different WACCs. Given these assumptions, we find a levelized cost of steel (LCOS) of
462 652 USD/t when green steel is produced in Ceará (see Section S4.3). Since the levelized cost is higher
463 than the operational expenditures, the difference is allocated to gross operating surplus (see Section
464 S5.2.3). A sensitivity analysis is performed to assess the impact of different assumptions on the cost of
465 capital on the results (see Section S6.2).

466 *Table S10 - Capital expenditures for a H-DRI-EAF steel plant of 4.77Mt production capacity*

CAPEX item	USD/t
Shaft furnace	100
Pre-Heater	3
Recycle compressor	6
EAF & Casting	205
Cooling tower	18
Buildings, storage, water service	66
Electrical & instrumentation	32
Other plant equipment	92
Preproduction costs	72
Inventory	38
Other owner costs	93
Total CAPEX	725

467

Table S11 - Operational expenditures for a 4.77Mt H-DRI-EAF steel plant in Ceará, Brazil. *Inputs where prices differ between export scenarios

Export scenario	Input	Input per ton of HRC	Unit price	USD per ton of steel
Green steel exports	Iron ore pellets (ton)	1.6	117.8	192
	Hydrogen (kg)*	67	4.17	279
	Natural gas (GJ)*	1.06	15.2	16
	Electricity (kWh)*	550	0.078	43
	Carbon (kg)	35.8	0.179	6
	Lime (kg)	51	0.100	5
	Raw water withdrawal(ton)	1.20	2.0	2
	Labor (FTE)*	0.0013	12142.4	15
	Steel transport	1	5	5
	Total OPEX/year			565
Green hydrogen exports	Iron ore pellets (ton)	1.6	117.8	192
	Hydrogen (kg)*	67	9.18	615
	Natural gas (GJ)*	1.06	7.43	8
	Electricity (kWh)*	550	0.073	40
	Carbon (kg)	35.8	0.179	6
	Lime (kg)	51	0.100	5
	Raw water withdrawal(ton)	1.20	2.0	2
	Labor (FTE)*	0.0013	94019	120
	Total OPEX/year			989

S2.3. Local content assumptions

Table S12 summarizes the assumptions on local content for the main inputs into green hydrogen production, renewable electricity generation, hydrogen liquefaction and storage, and green steel production. Assumptions for local content scenarios are based on a literature review, a field visit to the Port of Pecém in May 2022, and expert consultations. A detailed analysis of the qualitative data is available in an earlier publication[1] . Key experts were consulted again in September 2024 to revalidate assumptions and confirm their ongoing relevance.

Plant equipment is assumed to be either locally supplied whenever local capabilities exist ('high local content scenario') or imported ('low local content scenario'). Ceará is home to two wind turbine assembly factories: one from Vestas and one from Aeris. The Brazilian electrolyzer manufacturer Hytron has a memorandum of understanding (MoU) with the government of Ceará to construct an electrolyzer assembly plant in the state. However, no companies that manufacture solar panels, batteries, steel furnaces, or hydrogen liquefaction equipment, nor have any with plans to do so in the coming years could be identified. Hence, it is assumed that only wind turbines and electrolyzers could be supplied by local factories in the high local content scenario, while other equipment is always imported.

Iron ore is assumed to be mined in the Carajás mine, the largest in the world, located in the Brazilian state of Pará. The location for processing iron ore into iron pellets depends on both exports and local content scenarios. In the green steel exports scenario, it is either assumed that that iron ore is processed into iron ore pellets close to the Carajás mine and then transported to Pecém via rail (LowLC) or that approximately half of the iron ore pellets come from a local pelletizing plant (HighLC), with the remaining iron ore pellets coming from the pelletizing plant close to the Carajás mine. In the green hydrogen exports scenario, iron ore is assumed to be processed into iron ore pellets close to the Carajás mine

492 and then transported to IJmuiden (via rail followed by shipping), independently of local content
493 scenarios. Natural gas and coal are assumed to be always imported, as Ceará does not produce any
494 natural gas[53] or coal[54].

495 In addition, electricity is always assumed to be sourced locally, be it from the dedicated renewable
496 electricity generation facility (for the case of green hydrogen) or from the electricity grid (for the case of
497 liquefaction and storage and green steel).

498 Moreover, financial services and project management and engineering services can be local or
499 imported. Labor is always assumed to be sourced locally at the production location. When maintenance
500 services are outsourced, it is assumed that it takes the average import share of the economy. Real state
501 and in-land transport services are assumed to be sourced according to average import shares in the
502 economy.

503 These assumptions are operationalized as follows. In the LCA, the Ecoinvent datasets used to quantify
504 emissions for manufacturing wind turbines and electrolyzers have a global scope, limiting differentiation
505 between local content scenarios. For modelling wind turbine manufacturing, electricity is assumed to be
506 sourced locally in the high local content scenario (North-East Brazil grid mix), while in the low local
507 content scenario the global grid mix is used. Emissions from electrolyzer manufacturing, primarily from
508 the production of steel and other metals[55], were modelled using the same global market activities in both
509 local content scenarios, with no difference in emissions as a result. For iron ore pelletizing, the Ecoinvent
510 dataset for Quebec was adapted to make it applicable to the North-East of Brazil. Since both the Carajás
511 mine and Ceará fall within this region, it was not possible to distinguish between pelletizing close to the
512 Carajás mine (low local content) or in Ceará (high local content), with no difference in emissions as a
513 result.

514 In the cost analysis, data on equipment costs is not available according to the origin. Hence, a
515 quantitative analysis of the cost difference between different local content scenarios was not possible.
516 While there is some qualitative evidence indicating that Brazilian equipment could be more expensive[1],
517 this could not be translated into quantitative cost differences. Commodity inputs such as iron pellets and
518 coke are assumed to have a single global price as they are internationally traded. While services are
519 not internationally traded, local price data was not available, so prices from international studies are
520 taken instead. Prices for natural gas, electricity, and labor, are adjusted to reflect prices at the production
521 location (see Sections S2.2 and S4).

522 In the input-output modelling, this is operationalized by assigning local content shares to the investment
523 shock (construction phase) and to the expenditures of industries (operation phase) (see Section S5).

524 As explained before, for the LCA and the cost analysis, all steps are modelled up to when the green
525 steel is available to the steel user at the Port of IJmuiden, Netherlands. However, for the IO impact
526 analysis, only the economic activities taking place in Ceará are modelled. Depending on the exports
527 scenario, either the liquefaction and storage or the production of green steel in Ceará is modelled.

Table S12 - Local content assumptions

Production activity	Production location	Export scenarios	Input	Assumption	Operationalization		
					LCA	Cost analysis	IO
Green hydrogen	Pecém (Ceará)	Both	Equipment (electrolyzers, compressors, etc)	Local or imported from outside Ceará	Based on Krishnan et al.[56], using global Ecoinvent datasets	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share equals either 1 (HighLC) or 0 (LowLC)
			Renewable electricity	Always local (dedicated RE)	See below	Electricity price equals LCOE of dedicated system	Local content share always equals 1 (allocated to new RE sector)
			Water	Sourced from local market	Brazil-specific Ecoinvent dataset adapted for locally sourced electricity (SSP2-RCP2.6 2025 North-East Brazil grid)	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share from Ceará SUT
Renewable electricity	Pecém (Ceará)	Both	Wind turbines	Local or imported from outside Ceará	Global Ecoinvent dataset adapted for locally sourced electricity (HighLC) and global electricity mix (LowLC)	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share equals either 1 (HighLC) or 0 (LowLC)
			Solar panels	Always imported from outside Ceará	Global Ecoinvent dataset adapted to the Brazilian scope	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share always equals 0
			Battery system	Always imported from outside Ceará	Based on Bauer et al.[57], using global Ecoinvent datasets	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share always equals 0
Liquefaction and storage	Pecém (Ceará)	Both	Equipment	Always imported from outside Ceará	Based on Stolzenburg and Mubala[58]	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share always equals 0

			Electricity	Always local (from the grid)	SSP2-RCP2.6 2025 North-East Brazil grid	Grid electricity prices for industrial consumers in Ceará	Local content share equals share from Ceará SUT
Green steel	Pecém (Ceará)	Green steel exports	Equipment	Always imported from outside Ceará	Ecoinvent dataset for 'Rest of the World'	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share always equals 0
			Iron ore pellets	Assumed to be purchased from an external company processing iron ore into iron pellets located near the Carajás mine	Ecoinvent dataset for Quebec adapted to North-East Brazil geography	Global market price	Local content shares always equals 0
			Carbon	Assumed to come from coal (95% carbon content) mined outside of Ceará	Ecoinvent market process for coal in 'Latin America and the Caribbean'	Global market price	Local content shares always equals 0
			Natural gas	Assumed to be purchased in the Brazilian market	Ecoinvent market process for high pressure natural gas in Brazil	Natural gas prices in Brazil	Local content shares always equals 0
			Water	Always sourced from the local market	Ecoinvent dataset for water in North-East Brazil	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Local content share from Ceará SUT when produced in Pecém
			Electricity	Always local (from the grid)	SSP2-RCP2.6 2025 North-East Brazil grid	Grid electricity prices in the Netherlands and in Brazil	Local content share from Ceará SUT when produced in Pecém
	IJmuiden (Netherlands)	Green hydrogen exports	Equipment	Always imported from outside Ceará	Ecoinvent dataset for Europe	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Not modelled when steel is produced in IJmuiden

Iron ore pellets	Assumed to be purchased from an external company processing iron ore into iron pellets located near the Carajás mine	Ecoinvent dataset for Quebec adapted to North-East Brazil geography	Global market price	Not modelled when steel is produced in IJmuiden
Carbon	Assumed to come from coal (95% carbon content) mined outside of Ceará	Ecoinvent market process for coal in 'Europe, without Russia and Turkey'	Global market price	Not modelled when steel is produced in IJmuiden Not modelled when steel is produced in IJmuiden
Natural gas	Assumed to be purchased in the Dutch market	Ecoinvent market process for high pressure natural gas in the Netherlands	Natural gas prices in the Netherlands and in Brazil	Not modelled when steel is produced in IJmuiden Not modelled when steel is produced in IJmuiden
Water	Always sourced from the local market	Ecoinvent dataset for water in the Netherlands	Techno-economic studies (no data on cost difference for HighLC and LowLC available)	Not modelled when produced in IJmuiden
Electricity	Always local (from the grid)	SSP2-RCP2.6 2025 grid in the Netherlands	Grid electricity prices in the Netherlands	Not modelled when produced in IJmuiden

529

S3. Methodology: environmental life-cycle assessment

Environmental life-cycle assessment (LCA) is a methodology used to quantify the environmental impacts associated with a product or process. In this study, we specifically focus on greenhouse gas emissions or climate change impacts. The functional unit, which measures all inputs and outputs to the process, is defined as 1 kg of green steel (hot rolled coil) in IJmuiden.

Life-Cycle Inventory. To construct the life-cycle inventory, we use data previously published studies in combination with the Ecoinvent database v3.10.

Life-Cycle Impact Assessment. We employ the ReCiPe2016 method (H) v1.1 at midpoint level, using the climate change impact indicator to quantify the GHG emissions of the green hydrogen export and green steel export cases, as summarized in Table S1, and for a high local content and low local content scenario for green hydrogen production. This analysis is conducted using SimaPro v9.6 software in combination with R.

Interpretation. The GHG emissions for the green hydrogen export and green steel export cases are quantified for different steps in the supply chain, to identify the processes with the largest contribution to total GHG emissions. In the base case, we assume that the power input required in the DRI-EAF process is supplied by the local grid mix in the Netherlands (hydrogen export case) and in Brazil (steel export case), with the heat requirement met by natural gas (H2-NG-DRI). In the sensitivity analysis, we assess the impact of 1. using projected electricity grid mixes for 2030 and 2050 instead of 2025, 2. using hydrogen instead of natural gas for the heat requirement in steel production (H2-DRI), and 3. using electric freight trains instead of diesel-powered trains for iron ore transport.

S3.1. Green hydrogen production emissions

The total green hydrogen production emissions, $E_{production,H_2}$ (kgCO2-eq/kg H2), are calculated using Equation 7:

$$E_{production,H_2} = E_{electricity,H_2} + E_{water,H_2} + E_{KOH,H_2} + E_{electrolyser,H_2} + E_{battery,H_2} \qquad \text{Equation 7}$$

Where: $E_{electricity,H_2}$, E_{water,H_2}, E_{KOH,H_2}, $E_{electrolyser,H_2}$, and $E_{battery,H_2}$ are the emissions in kgCO2-eq/kg H2 associated with the manufacturing of the electricity plant, water supply, potassium oxide (KOH) supply, and the manufacturing of the electrolyzer and battery, respectively.

S3.1.1. Modelling GHG emissions of dedicated renewable electricity

The emissions from manufacturing the electricity plant that powers the electrolyzer are determined by the size of the solar PV and wind power plants needed to provide continuous electricity, in combination with the battery. These emissions ($E_{electricity,H_2}$, in kgCO2-eq/kg H2), are calculated by dividing the total emissions from wind turbine and solar panel manufacturing by the total hydrogen production over the electrolyzer's lifetime (Q_{H_2}, in kt H2), as shown in Equation 8:

$$E_{electricity,H_2} = \frac{\frac{cap_{facility,ren}}{cap_{unit,solar}} \cdot EF_{unit,solar} + \frac{cap_{facility,ren}}{cap_{unit,wind}} \cdot EF_{unit,wind}}{Q_{H_2} \cdot 10^6} \qquad \text{Equation 8}$$

Where: $cap_{unit,solar}$ and $cap_{unit,wind}$ are the capacities (GW) of a single wind or solar PV unit, respectively, and $EF_{unit,solar}$ (kgCO2-eq) and $EF_{unit,wind}$ (kgCO2-eq) are the manufacturing emissions of these single units, respectively.

S3.1.1.1. Modelling GHG emissions of the solar PV facility

We use Ecoinvent data for a 570 kWp ground-mounted PV plant, which has lower manufacturing emissions than residential solar PV panels. The Ecoinvent process includes the manufacture of inverters, wafers, mounting system, and electrical installation. The electricity source used in manufacturing is assumed to be the global grid mix. The electricity requirements are as follows: 4577.8 kWh per 500 kW inverter manufacture (requiring 3.13 inverters per 570 kWp installation), 4.7 kWh per m² wafer (requiring 4401.7 m²), and 36 kWh for the erection of the installation. For the erection of the

574 installation, the grid mix in North-East Brazil is used. The emissions of the 570 kWp installation are
575 scaled to the required installed capacity, calculated using Equation 3.

S3.1.1.2. Modelling GHG emissions of the onshore wind facility

577 We model the emissions associated with onshore wind turbines based on the Ecoinvent entry for the
578 construction and connection of a 4.5 MW onshore wind turbine with a lifetime of 20 years. The electricity
579 requirement for the construction of the wind turbine is 445,000 kWh, with the electricity source adjusted
580 based on the local content scenario: in the high local content scenario turbines are manufactured locally
581 and the grid mix of North-East Brazil is used, while in the low local content scenario the turbines are
582 imported from elsewhere, so the global grid mix is used. The emissions of the 4.5 MW installation are
583 scaled to the required installed capacity, calculated using Equation 3.

S3.1.2. Modelling GHG emissions of water use

585 We assume that water supply is deionized tap water. The emissions associated with water use in green
586 hydrogen production, E_{water,H_2} (kgCO2-eq/kg H2), are calculated using Equation 9:

$$E_{water,H_2} = (N_{water,feed} + N_{water,cooling}) \cdot (E_{tap} + E_{deionisation})$$

Equation 9

587

588 Where: $N_{water,feed}$ and $N_{water,cooling}$ are the required feed water and cooling water, respectively (kg
589 H2O/kg H2) (Table S2), E_{tap} the emissions associated with tap water (kgCO2-eq/kg H2O), and
590 $E_{deionisation}$ the emissions associated with deionisation (kgCO2-eq/kg H2O). We use the Brazil-specific
591 process in Ecoinvent for tap water, and adapt the general Ecoinvent process for water deionization by
592 excluding the water input and adjusting the electricity source for the $2.6 \cdot 10\text{-}5$ kWh/kg H2O electricity
593 requirement to the grid mix of North-East Brazil.

S3.1.3. Modelling GHG emissions of the potassium oxide electrolyte

595 The emissions associated with the production of the potassium oxide (KOH) electrolyte used in the
596 electrolyzer, E_{KOH,H_2} (kgCO2-eq/kg H2), are calculated using Equation 10:

$$E_{KOH,H_2} = \frac{cap_{electrolyser}}{M_{H_2}} \cdot N_{KOH} \cdot EI_{KOH}$$

Equation 10

597

598 Where: N_{KOH} is the annual KOH demand per MW of electrolyzer (kg KOH per year per MW) and EI_{KOH}
599 the emissions of KOH production (kgCO2-eq/kg KOH).

S3.1.4. Modelling GHG emissions of electrolyzer manufacturing

601 We use an average of alkaline electrolyzers based on the manufacture of a baseline (2020) and a more
602 advanced (2030) design(Krishnan et al., 2024). This includes the manufacturing of the electrolyzer
603 stacks, which have a lifetime of 8 years ($lifetime_{stacks}$), and the balance of plant (BOP), which has a
604 lifetime of 20 years ($lifetime_{electrolyser}$). Emissions from electrolyzer manufacturing ($E_{electrolyser,H_2}$ in
605 kgCO2-eq/kg H2) are calculated by scaling the emissions found by Krishnan et al.[2] based on 4161
606 operating hours per year to the 7940 hours in our system (Equation 11). This adjustment is necessary
607 because manufacturing emissions are divided over the total hydrogen produced over the electrolyzer's
608 lifetime, and more hydrogen is produced if operational hours are increased.

$$E_{electrolyser,H_2} = (EF_{BOP} + EF_{stacks}) \cdot \frac{4161}{7940}$$

Equation 11

609

610 Where: EF_{BOP} are emissions from the 2025 average construction of the BOP based on 4161 operational
611 hours per year (kgCO2-eq/kg H2), and EF_{stacks} are the manufacturing emissions of the stacks in 2025
612 based on 4161 operational hours per year (kgCO2-eq/kg H2).

613 Emissions from electrolyzer manufacturing mainly come from producing steel and other metals.
614 Assuming conventional steel from a market mix is used, these emissions remain unchanged across
615 different local content scenarios.

S3.1.5.   Modelling GHG emissions of battery manufacturing

617 The lithium nickel manganese cobalt oxide battery system includes battery pack, battery management
618 system, energy management system, thermal management system, system container, inverter, and
619 transport. The battery's nameplate capacity (MWh) is calculated by multiplying the electrolyzer capacity
620 by the battery's storage duration ($hours_{battery}$ in hours), and is 12 GWh in our analysis (see Section
621 S2.1). To determine the battery manufacturing emissions ($E_{battery,H_2}$ in kgCO$_2$-eq/kg H$_2$), divide the
622 emission per storage capacity ($EF_{battery,MWh}$ in kgCO$_2$-eq/MWh) by the total hydrogen produced over
623 the electrolyzer's lifetime (Q_{H_2}, in kt H$_2$), adjusted for the relative lifetimes of the battery and electrolyzer.

$$E_{battery,H_2} = \frac{cap_{electrolyser} \cdot hours_{battery}}{Q_{H_2}} \cdot EF_{battery,MWh} \cdot \frac{lifetime_{electrolyser}}{lifetime_{battery}} \qquad \text{Equation 12}$$

624

625 The battery lifetime ($lifetime_{battery}$) is assumed to be 12 years[57]. $EF_{battery,MWh}$ depends on the
626 emissions intensity of electricity used in manufacturing. We use the mean GHG emissions for battery
627 manufacture in 2020 and 2030 (2°C scenario), as quantified by Bauer et al. [57], which is $87.0 \cdot 10^3$ kgCO$_2$-
628 eq/MWh storage capacity.

S3.2.   Hydrogen liquefaction and shipping emissions

630 Hydrogen liquefaction to prepare gaseous hydrogen for shipping in the green hydrogen export case is
631 assumed to take place in liquefaction facilities with a capacity of 50 tH$_2$/day, which include up to 21 days
632 of storage capacity[58]. Based on the average daily production, 18 of these units are needed. Section
633 S2.1.3 detailed the assumptions on liquefaction and shipping, and the life-cycle inventory used to
634 quantify the emissions can be found in Supplementary Table 8 in de Kleijne et al.[12].
635
636 The emissions of hydrogen liquefaction (E_{liqf,H_2} in kgCO$_2$-eq/kg H$_2$) are quantified following Equation
637 13:
638

$$E_{liqf,H_2} = \frac{1}{1 - L_{liqf}} \cdot \left(P_{liqf} \cdot EI_{grid,BR} + EF_{liqf\ plant} + L_{liqf} \cdot GWP_{H_2} \right) \qquad \text{Equation 13}$$

639 Where L_{liqf} is the loss of hydrogen (as a mass fraction) during liquefaction, GWP_{H_2} the global warming
640 potential of hydrogen (Section S3.6), P_{liqf} the liquefaction electricity requirement (in kWh/kg H$_2$),
641 $EI_{grid,BR}$ the emissions intensity of the North-East Brazilian grid mix (in kgCO$_2$-eq/kWh, see Section
642 S3.1.1), and $EF_{liqf\ plant}$ the manufacturing emissions of the liquefaction facility, scaled to emissions per
643 kg of hydrogen liquefied based on its lifespan and total hydrogen liquefied over the lifespan (kgCO$_2$-
644 eq/kg H$_2$).
645
646 During liquid hydrogen storage at land until a tanker can be filled (up to 13 days), all boil-off gas that is
647 formed is first compressed (Equation 14) and then (re-)liquefied (Equation 13).
648

$$E_{comp,H_2} = \frac{1}{1 - L_{comp}} \cdot \left(P_{comp} \cdot EI_{grid,BR} + EF_{comp\ plant} + L_{comp} \cdot GWP_{H_2} \right) \qquad \text{Equation 14}$$

649 Where E_{comp,H_2} are the emissions of hydrogen compression (in kgCO$_2$-eq/kg H$_2$), L_{comp} is the loss of
650 hydrogen (as a mass fraction) during compression, P_{comp} the compression electricity requirement (in
651 kWh/kg H$_2$), and $EF_{comp\ plant}$ the manufacturing emissions of the compression facility, scaled to
652 emissions per kg of hydrogen compressed based on its lifespan and total hydrogen compressed over
653 the lifespan (kgCO$_2$-eq/kg H$_2$).
654
655 The emissions of hydrogen loading into the tanker (E_{load,H_2} in kgCO$_2$-eq/kg H$_2$) are quantified following
656 Equation 15:

$$E_{load,H_2} = \frac{1}{1 - L_{load}} \cdot \left(P_{load} \cdot EI_{grid,BR} + L_{load} \cdot GWP_{H_2} \right) \qquad \text{Equation 15}$$

657   Where L_{load} is the loss of hydrogen (as a mass fraction) during loading, and P_{load} the loading electricity
658   requirement (in kWh/kg H₂).
659
660   The emissions of hydrogen shipping in the tanker (E_{ship,H_2} in kgCO₂-eq/kg H₂) are quantified following
661   Equation 16:

$$E_{ship,H_2} = \frac{1}{1 - L_{BOG,day} \cdot d_{journey,day}}$$
$$\cdot \left(d_{journey,km} \cdot EI_{ship} + L_{BOG,day} \cdot d_{journey,day} \cdot GWP_{H_2} \right)$$

Equation 16

662   Where $L_{BOG,day}$ is the rate of hydrogen loss through boil-off gas (as a mass fraction per day), $d_{journey,day}$
663   the length of the journey in days, $d_{journey,km}$ the length of the journey in km (one-way), and EI_{ship} the
664   emissions intensity of hydrogen shipping per km (voyage and ballast, including fuel and the
665   manufacturing of the tanker).
666
667   The emissions of hydrogen unloading from the tanker (E_{unload,H_2} in kgCO₂-eq/kg H₂) are quantified
668   following Equation 17:

$$E_{unload,H_2} = \frac{1}{1 - L_{unload}} \cdot \left(P_{unload} \cdot EI_{grid,NL} + L_{unload} \cdot GWP_{H_2} \right)$$

Equation 17

669   Where L_{unload} is the loss of hydrogen (as a mass fraction) during unloading, and P_{unload} the unloading
670   electricity requirement (in kWh/kg H₂).
671
672   The emissions of hydrogen regasification and storage ($E_{storage,H_2}$ in kgCO₂-eq/kg H₂) are quantified
673   following Equation 18:
674

$$E_{storage,H_2} = \frac{1}{1 - L_{comp}} \cdot \left(L_{comp} \cdot GWP_{H_2} \right) + EF_{storage,manufacture}$$

Equation 18

675   Where $EF_{storage,manufacture}$ are the manufacturing emissions of the storage facility on land with a
676   capacity of 3 days, scaled to emissions per kg of hydrogen stored based on the lifespan of the facility
677   and total hydrogen stored over the lifespan (kgCO₂-eq/kg H₂).
678
679   In general, as losses occur in several consecutive steps of hydrogen processing and transport, more
680   than 1 kg of hydrogen needs to be produced, processed and transported to arrive with 1 kg at the
681   destination. In addition to accounting for hydrogen losses to the environment in the relevant steps
682   through its global warming potential, the relative processing requirement (and associated emissions) in
683   each previous step is increased according to Equation 19:
684

$$E_{i,total} = \frac{1}{1 - L_{i+1}} \cdot E_i$$

Equation 19

685   Where E_i are the emissions of step i (e.g., liquefaction, loading, shipping) in kgCO₂-eq/kg H₂ processed,
686   L_{i+1} are the losses of hydrogen in step $i + 1$, as a fraction, and $E_{i,total}$ the total emissions of step i
687   accounting for the increased processing requirement to have 1 kg of hydrogen after step $i + 1$.
688

689   ## S3.3.   Iron ore mining, pelletizing and transport emissions
690   Iron ore pellets are used as input for the shaft furnace, where together with hydrogen, sponge iron is
691   produced (Table S4). The process of iron ore pellet production starts with iron ore mining (assumed to
692   take place in the Carajás mine, see Section S2.1.4), followed by iron ore pelletizing, land transport by
693   rail, and possibly shipping, depending on the export scenario. In the green steel export case, steel
694   production takes place in the Port of Pecém, to which the iron ore is transported by rail covering a
695   distance of approximately 2000 km (Table S13). In the green hydrogen export case, iron ore is
696   transported by rail to the nearest port, followed by shipping (Table S13).

697   The emissions associated with iron ore pellets ($E_{iron\ ore}$ in kgCO₂-eq/kg iron ore) are quantified following
698   Equation 20:

$$E_{iron\ ore} = E_{ore,mining} + E_{ore,pelletizing} + E_{rail,ore} \cdot d_{rail,ore,km} + E_{ship,ore} \cdot d_{ship,ore,km}$$

<div align="right">*Equation 20*</div>

699 Where $E_{ore,mining}$ are the emissions for iron ore mining (in kgCO$_2$-eq/kg iron ore), $E_{ore,pelletizing}$ are the
700 emissions for iron ore pellet production (in kgCO$_2$-eq/kg iron ore), $E_{rail,ore}$ the emissions for iron pellet
701 transport by rail including train manufacture and fuel (in kgCO$_2$-eq/kg iron ore/km), $E_{ship,ore}$ the emissions
702 of iron pellet transport by ship including ship manufacture and fuel (in kgCO$_2$-eq/kg iron ore/km),
703 $d_{rail,ore,km}$ the distance of iron pellet transport by rail in km, and $d_{ship,ore,km}$ the distance or iron pellet
704 transport by ship in km. Note that $E_{iron\ ore}$ is dependent on the export scenario.

705 Ecoinvent processes are used to calculate the emissions associated with these processes. The
706 Ecoinvent entry for iron ore pellet production in Quebec is adapted to the North-East Brazilian situation
707 by selecting location-specific input processes, such as electricity from the North-East Brazilian grid mix.
708 In the high local content scenario, pelletizing is assumed to take place close to the Carajás mine, outside
709 of Ceará, while in the low local content scenario, pelletizing is assumed to take place in Ceará. Since
710 both these locations fall within the region of North-East Brazil, this resulted in no difference in the
711 datasets used.

712 For rail transport and shipping, the Ecoinvent entry for a diesel-powered freight train and 'Transport,
713 freight, sea, bulk carrier for dry goods (global)' are used, respectively. In the sensitivity analysis, an
714 electric freight train is used instead of the diesel-powered freight train, again based on Ecoinvent,
715 powered by grid electricity.

716
717 *Table S13 - Overview of iron ore mining, pelletizing and transport processes in the green hydrogen export scenario*
718 *and green steel export scenario*

	Green hydrogen export	Green steel export
	Input per ton iron ore	Input per ton iron ore
Iron ore concentrate production (mining)	1 ton	1 ton
Iron ore pelletizing	1 ton	1 ton
Transport by freight train	1000 km	2000 km
Transport by ship	7600 km	-

719

S3.4. Steel production and transport emissions

721 To calculate the emissions of steel production, the life-cycle inventory from Rosner et al.[19] is used,
722 specifically, the 'H$_2$-DRI base case: H$_2$ use for shaft furnace. Natural gas (NG) use for H$_2$ pre-heating,
723 EAF heating, ladle heating'. To this, the construction of an electric arc furnace, refractory lining and
724 anode is added, based on the Ecoinvent entry for electric low-alloyed steel production (see Table S4;
725 H$_2$-NG-DRI case). For the sensitivity analysis, the 'H$_2$-DRI total case: H$_2$ use for shaft furnace, H$_2$ pre-
726 heating, EAF heating, ladle heating' is used as the basis, subject to the same additions based on the
727 Ecoinvent entry for electric low-alloyed steel production (Table S4; H$_2$-DRI case).

728 While steel is produced in IJmuiden in the green hydrogen export case, in the green steel export case
729 steel is shipped by a dry bulk carrier from the Port of Pecém to the Port of IJmuiden, covering a distance
730 of approximately 7500 km.

731 The emissions associated with steelmaking (E_{steel} in kgCO$_2$-eq/kg steel) are quantified following
732 Equation 21:
733

$$E_{steel} = N_{H_2} \cdot E_{H_2} + N_{iron\ ore} \cdot E_{iron\ ore} + E_{steel,ex.elec} + P_{EAF} \cdot EI_{grid} + E_{ship,steel} \\ \cdot d_{ship,steel,km}$$

<div align="right">*Equation 21*</div>

734

735 Where: N_{H_2} and $N_{iron\ ore}$ are the hydrogen and iron ore requirements in kg H$_2$ per kg steel, and kg iron
736 ore per kg steel, respectively; E_{H_2} and $E_{iron\ ore}$ the export-scenario dependent emissions for hydrogen
737 and iron ore inputs, in kgCO$_2$-eq/kg H$_2$ and kgCO$_2$-eq/kg iron ore, respectively; $E_{steel,ex.elec}$ are the

738 location-dependent emissions associated with DRI-EAF steelmaking, excluding electricity (kgCO₂-eq/kg
739 steel), P_{EAF} the electricity requirement of the EAF (kWh/kg steel), EI_{grid} the location-dependent
740 emissions intensity of the grid mix (kgCO₂-eq/kWh, see section S2.1.2), $E_{ship,steel}$ the emissions of steel
741 transport by ship including ship manufacture and fuel (in kgCO₂-eq/kg steel/km), and $d_{ship,steel,km}$ the
742 distance of steel shipping in km (zero in the green hydrogen export case). Note that E_{steel} depends on
743 the export scenario.

744 In the green hydrogen export case, hydrogen losses from liquification and shipping add up to an
745 approximate loss of 7%. Therefore, effectively more hydrogen production is required per kg of steel
746 produced (or, conversely, less steel can be manufactured per kg of hydrogen produced). This has been
747 accounted for in the analysis by including not only the emissions of hydrogen production (Equation 7),
748 and of hydrogen transport (Equation 13-Equation 18) in the total emissions of hydrogen inputs to the
749 steelmaking process (E_{H_2}, in kgCO₂-eq/kg H₂), but also correcting for losses following Equation 19.

750 In the sensitivity analysis where we assess sponge iron production in Ceará and shipping to IJmuiden
751 for EAF-steelmaking, the H₂-NG-DRI case is adapted according to Table S5. The relevant local
752 processes are used, such as the North-East Brazilian grid mix for DRI processes requiring electricity,
753 and the Dutch grid mix for EAF processes. Since sponge iron has a mass of 1.16 times that of finished
754 steel[19], shipping emissions are increased by a factor 1.16 compared to shipping steel from Ceará to
755 IJmuiden.

S3.5.   Modelling GHG emissions of grid electricity

757 Except for electrolysis, we assume grid electricity (high voltage) is used for component manufacturing,
758 hydrogen liquefaction, hydrogen compression, and the electric arc furnace, in the respective locations.

759 The life-cycle GHG emission intensity of grid electricity is projected using the Premise open-source
760 Python package (version 2.0.2) under an SSP2-RCP2.6 (2°C) scenario. The 2025 grid mix is used in
761 the main analysis, and values for 2030 and 2050 in the sensitivity analysis. As the grid mix decarbonizes,
762 the emission intensity is projected to decrease, potentially reaching negative values in 2050 for the
763 Netherlands and the global market mix (-11.9 and -7 gCO₂-eq/kWh, respectively). However, to avoid
764 skewing results by leading to lower emissions with increased electricity use, we assume an emission
765 intensity of 0 for these two cases for 2050 (Table S14).

766 *Table S14 - Emissions intensities used for grid electricity in North-East Brazil, the Netherlands and the global*
767 *average, projected for 2025, 2030 and 2050 under a 2°C scenario*

	2025	2030	2050
North-East Brazil (gCO₂-eq/kWh)	141.5	103.8	7.0
The Netherlands (gCO₂-eq/kWh)	303.2	258.5	0
Global market mix (gCO₂-eq/kWh)	683.1	496.0	0

768

S3.6.   Hydrogen as indirect greenhouse gas

770 Hydrogen is an indirect greenhouse gas, which means that when it reaches the atmosphere, it interacts
771 with other components in the atmosphere, resulting in a net warming effect. The global warming potential
772 of 1 kg of hydrogen, over a 100 year time horizon, is 11.6 kgCO₂-eq/kg H₂[16].

S4.   Methodology: Cost analysis

S4.1.   Levelized cost of green hydrogen (LCOH)

775 The sales price of green hydrogen at the electrolysis plant is considered to be the levelized cost of
776 hydrogen production. The LCOH is calculated as in Equation 22.

777

$$LCOH = \frac{\sum_{t=1}^{n} \dfrac{I_{H2_t} + OM_{H2_t} + LCOE * P_{electrolyser} * M_{H2_t}}{(1 + WACC_{H2})^t}}{\sum_{t=1}^{n} \dfrac{M_{H2_t}}{(1 + WACC_{H2})^t}}$$

<div align="right">*Equation 22*</div>

Where I_{H2_t} is the investment (CAPEX) expenditure for electrolysis in year t, $OM_{H2,t}$ is the operational expenditures for electrolysis excluding electricity inputs in year t, $WACC_{H2}$ is the weighted average cost of capital for electrolysis, $P_{electrolyser}$ is the electricity requirement for electrolysis per kilogram of hydrogen output, M_{H2_t} is the hydrogen output of the electrolysis plant at year t, and $LCOE$ is the levelized cost of electricity.

The levelized cost of electricity for electrolysis is calculated based on the system design and the cost assumptions from Section S2 and the following formula:

$$LCOE = \frac{\sum_{t=1}^{n} \dfrac{I_{wind_t} + OM_{wind_t} + I_{solar_t} + OM_{solar_t} + I_{battery_t} + OM_{battery_t}}{(1 + WACC_{RE})^t}}{\sum_{t=1}^{n} \dfrac{P_{electrolyser} * M_{H2_t}}{(1 + WACC_{RE})^t}}$$

<div align="right">*Equation 23*</div>

Based on the assumptions from Sections S2.1.1, S2.1.2, S2.2.1, and S2.2.2, the LCOH obtained in this study is 4.17 USD/kgH$_2$, excluding any hydrogen liquefaction, storage, or shipping costs. This somewhat higher LCOH when compared to IRENA's estimates can be explained by the need to oversize the renewable energy facilities and to add a battery considering the assumption of dedicated generation. This is based on the calculated levelized cost of electricity (LCOE) for the entire system (including energy storage) of 0.06417 USD/kWh.

S4.2. Levelized cost of liquefaction and storage (LCOLS)

The levelized cost of liquefaction and storage is calculated as in Equation 24. The quantity of hydrogen yearly sold by the liquefaction and storage step will be equal to the yearly production of the electrolysis plant M_{H2_t} minus the total losses in during liquefaction and storage L_{LS}. The total losses amount to 1.89% (see Section S3.2), meaning that of the 319kton/year of green hydrogen produced by electrolysis, only 313kton/year will be available to be loaded into the ship.

$$LCOLS = \frac{\sum_{t=1}^{n} \dfrac{I_{liquefaction_t} + OM_{liquefaction_t} + I_{storage_t} + OM_{storage_t}}{(1 + WACC_{LS})^t}}{\sum_{t=1}^{n} \dfrac{M_{H2_t} * (1 - L_{LS})}{(1 + WACC_{LS})^t}}$$

<div align="right">*Equation 24*</div>

We find a LCOLS of 2.49 USD/kgH2, which is in the mid-range of the costs reported by IRENA[41]. This can be explained by the relatively small scale of the plant.

S4.3. Levelized cost of green steel (LCOS)

The levelized cost of green steel (LCOS) is different in the two export scenarios. The costs for steel production are described in Section S2.2.5. We assume the steel plants in Ceará and in the Netherlands would pay different total prices for green hydrogen, with the difference referring to the additional steps necessary to liquefy, store, ship, and regasify the green hydrogen when transporting the green hydrogen from Pecém to IJmuiden. Additionally, prices for electricity and natural gas are different in the two locations, and so are labor costs. Hence, steel plants at the two locations will have different operation and management costs (OM). Also, they will have different physical output of green steel (GSP) for a given size of the electrolysis plant in Ceará, due to hydrogen losses in transport. Both locations are assumed to have the same investment costs per tonne of steel capacity and weighted average cost of capital.

$$LCOS_{IJmuiden} = \frac{\sum_{t=1}^{n} \dfrac{I_{GS_t} + OM_{IJmuiden_t}}{(1 + WACC_{GS})^t}}{\sum_{t=1}^{n} \dfrac{GSP_{IJmuiden_t}}{(1 + WACC_{GS})^t}}$$

Equation 25

$$LCOS_{Pecém} = \frac{\sum_{t=1}^{n} \dfrac{I_{GS_t} + OM_{Pecém_t}}{(1 + WACC_{GS})^t}}{\sum_{t=1}^{n} \dfrac{GSP_{Pecém_t}}{(1 + WACC_{GS})^t}}$$

Equation 26

811

S5.   Methodology: Input-output modelling

S5.1.   Model specification

In a input-output model with n industry sectors, z_{ij} is an element of the $n \times n$ inter-industry transactions matrix Z $[z_{ij}]$, representing the value of purchases of industry i output by industry j [59]. The n-element vector of total industry outputs is defined as x = $[x_i]$, where

$$x_i = z_{i1} + \cdots + z_{in} + f_i$$

Equation 27

and f_i is industry i's sales to final demand. The matrix of direct technical coefficients A = $[\alpha_{ij}]$ represents the value of dollars' worth of input from sector i per dollars' worth of output of sector j, where

$$\alpha_{ij} = z_{ij}/x_j \quad \forall\, i, j = 1, 2, \dots n$$

Equation 28

The total requirements matrix L = $[l_{ij}]$, also known as the Leontief inverse, is defined by, in matrix notation,

$$L = (I - A)^{-1}$$

Equation 29

where A is the matrix of direct technical coefficients and I is an identity matrix of $n \times n$ dimension [59]. In matrix notation:

$$A = Z\hat{x}^{-1}$$

Equation 30

$$x = Ax + f$$

Equation 31

$$x = (I - A)^{-1}f = Lf$$

Equation 32

The impact on output from industry sector j (Δx_j) given a change in final demand from sector i (Δf_i) will be given by:

$$\Delta x = L\Delta f$$

Equation 33

During the construction phase, the change in the final demand vector regards the additional inputs required for the construction of the plants. In the operation phase, it equals the exports of liquified green hydrogen (green hydrogen exports scenario) or the exports of green steel (green steel exports scenario). In both export cases, since these two products are not consumed by existing industries in Ceará, the total exports equal the total output of the sector (liquefaction of green hydrogen or green steel production).

The following sections summarize the input-output methodology in this study. Starting from the right side of the Equation 33, we first explain the model specification regarding the Leontief inverse (L) and the change in final demand (Δf) in Section S5.2. We then explain how the output, value-added, income and employment effects are determined in Section S5.3.

S5.2.   Model inputs

This study utilizes the Supply and Use tables (SUTs) for the state of Ceará from the year 2018 to derive the Leontief inverse for the region[20]. These tables are structured as 12x12 commodity-by-industry matrices (see Table S15). The procedure for converting the SUTs into an industry-by-industry IOT is based on Guilhoto and Sesso Filho [60,61] and Miller and Blair[59]. This is explained in Section S5.2.1.

The green industries had to be introduced into the table. The approach followed was based on Miller and Blair[59]. This is explained in Section S5.2.2 for the construction phase and in Section S5.2.3 for the operation phase.

In order to capture induced effects, households are endogenized, taking salary and employment data from the RAIS database from the Brazilian Ministry of Employment [26]. This is explained in Section S5.2.4.

Table S15 - Sectors in the SUTs

i	Sector
1	S01: Agriculture
2	S02: Extractive Industries
3	S03: Transformation industries
4	S04: Electricity, gas, water and other utilities
5	S05: Construction
6	S06: Commerce
7	S07: Transport, storage and post services
8	S08: Information and communication
9	S09: Financial activities, insurances and related fees
10	S10: Real estate activities
11	S11: Other activities and services
12	S12: Public administration, defence, healthcare, education and social security

S5.2.1.   Input output tables for the state of Ceará

The IBGE provides Use Tables in consumer prices and Supply Tables in producers prices. Moreover, in the Use Tables they show the total use of commodities by industries, not differentiating on whether the commodity is supplied domestically or imported. We follow Guilhoto and Sesso Filho [60,61] to obtain tables containing only the domestic (Ceará) supply at basic prices. We first remove the trade margins (MGC), transport margins (MGT) and taxes net of subsidies (IIL) from the Use Tables at consumer prices to obtain the use tables in basic prices.

$$TSBP = TSCP - MGC - MGT - IIL \qquad \text{Equation 34}$$

where:

TSBP = Total Supply at Basic Prices

TSCP = Total Supply at Consumers Prices

MGC = Trade margins

MGT = Transport margins

IIL = Taxes net of subsidies

Secondly, to obtain the domestic supply only, imports from rest of Brazil (IOB) and imports from rest of the world (IOW) are calculated and also removed from the Use table:

$$DSBP = TSBP - IOB - IOW \qquad \text{Equation 35}$$

where:

DSBP = Domestic Supply at Basic Prices

TSBP = Total Supply at Basic Prices

866   IOB = Imports from the rest of Brazil

867   IOW = Imports from the rest of the World

868

869   With the Use Table including only the domestically available supply at basic prices (U), the matrix of
870   containing the use structure of industries (B) can be obtained. As explained by Miller and Blair [59], the
871   vector of total industry output can be calculated by

$$x = (I - DB)^{-1}f$$

Equation 36

872   where:

873   x is the vector of total industry output;

874   B is the use structure matrix containing the use coefficients representing the value of inputs of
875   each commodity by dollars' worth of industry j's output, defined by $B = U\hat{x}^{-1}$;

876   D is the market shares matrix, defined by $D = S'\hat{q}^{-1}$, where q is the total commodity output and
877   S the supply matrix;

878   I is the identity matrix;

879   f is the vector of final demand for industries, defined by $f = De$, where e is the final demand for
880   commodities and D the market shares matrix.

881   The total requirements matrix $(I - DB)^{-1}$ becomes hence the equivalent of the Leontief's inverse (L),
882   where DB is the equivalent of the industry-by-industry technical coefficient matrix A[59].

$$A = DB$$

Equation 37

$$L = (I - DB)^{-1}$$

Equation 38

883   The impact on output can then be calculated using Equation 33.

884   *S5.2.2.   Modelling impacts from investments in the construction phase*

885   In the construction phase, the capital expenditures for each of the new plant *k* (renewable electricity,
886   green hydrogen, liquefaction and storage, and green steel) described in Section S2.2 are allocated to
887   the existing economic sectors in Ceará (see Table S16). For this, total expenditures need to first be
888   disaggregated into imported and domestic expenditures via local content shares.

$$f_{i,n+k}^{C^D} = f_{i,n+k}^{C^T} - f_{i,n+k}^{C^M}$$

Equation 39

889   where

890        $f_{i,n+k}^{C^T}$ is the total capital expenditure of the new industry k allocated to industry sector *i*

891        $f_{i,n+k}^{C^D}$ is the capital expenditure of the new industry k in the domestic industry sector *i*

892        $f_{i,n+k}^{C^M}$ is the capital expenditure of the new industry k allocated to industry sector *i* spent in
893   imports

894

895   Local content shares vary according to local content scenarios *s* (high and low), as previously explained.

$$f_{i,n+k}^{C^{D,s}} = f_{i,n+k}^{C^T} * lcs_{i,n+k}^{C^s} \ \forall \ i = 1,2, \dots n$$

Equation 40

896   Then, the vector of change in final demand for domestic industries is the vector obtained by summing
897   the capital expenditures for a given sector from all k new industries that will arise under export case t.
898   That is, while the renewable electricity and green hydrogen electrolysis plants will be built in both export
899   cases, a liquefaction and storage plant needs to be built in the case of green hydrogen exports, but not
900   in the case of green steel exports (and vice-versa).

$$f_i^{C^{D,s,t}} = \sum_{k=1}^{n_k} f_{i,n+k}^{C^{D,s,t}} \ \forall \ i = 1,2,..n \qquad \text{\textit{Equation 41}}$$

$$\Delta f_i^{C^{s,t}} = f_i^{C^{D,s,t}} \ \ \forall \ i = 1,2,..n \qquad \text{\textit{Equation 42}}$$

901 Then, the impact on output in the construction phase can be obtained by post-multiplying the equivalent
902 of the Leontief inverse by the change in final demand.

$$\Delta x^{C^{s,t}} = L \Delta f^{C^{s,t}} \qquad \text{\textit{Equation 43}}$$

903 *Table S16 - Sectoral allocation during construction phase*

Technology	Cost item	Sector	Value	Unit
Battery	Battery system	S03: Transformation industries	1410.0	USD/kW
Green Steel	Shaft furnace	S03: Transformation industries	99.8	USD/t
Green Steel	Pre-Heater	S03: Transformation industries	3.1	USD/t
Green Steel	Recycle compressor	S03: Transformation industries	6.3	USD/t
Green Steel	EAF & Casting	S03: Transformation industries	204.6	USD/t
Green Steel	Cooling tower	S03: Transformation industries	17.6	USD/t
Green Steel	Buidings, storage, water service	S05: Construction	66.4	USD/t
Green Steel	Electrical & instrumentation	S03: Transformation industries	32.3	USD/t
Green Steel	Other plant equipment	S03: Transformation industries	91.9	USD/t
Green Steel	Preproduction costs	S03: Transformation industries	71.8	USD/t
Green Steel	Inventory	S03: Transformation industries	38.0	USD/t
Green Steel	Other owner costs	S11: Other activities and services	93.2	USD/t
Green Hydrogen	Electrolyzer (Stack)	S03: Transformation industries	321.0	USD/kWH2
Green Hydrogen	Balance of plants (Gas separation, compression and gas treatment)	S03: Transformation industries	110.0	USD/kWH2
Green Hydrogen	Utilities and Process Automation (Water, piping, ICT)	S03: Transformation industries	86.0	USD/kWH2
Green Hydrogen	Power supply and electronics (Electrical installations)	S03: Transformation industries	196.0	USD/kWH2
Green Hydrogen	Civil, Structural & Architectural (Construction)	S05: Construction	22.0	USD/kWH2
Green Hydrogen	Contingency	S09: Financial activities insurances and related fees	120.0	USD/kWH2
Green Hydrogen	Developer cost	S11: Other activities and services	48.0	USD/kWH2
Green Hydrogen	Indirect costs	S11: Other activities and services	120.0	USD/kWH2
Liquefaction and storage	Storage	S03: Transformation industries	87.0	USD/kWH2
Liquefaction and storage	Equipment	S03: Transformation industries	489.4	USD/kWH2
Liquefaction and storage	Bulk materials	S03: Transformation industries	404.3	USD/kWH2
Liquefaction and storage	Construction	S05: Construction	383.0	USD/kWH2
Liquefaction and storage	Transport and freight of equipment	S07: Transport storage and post services	63.8	USD/kWH2
Liquefaction and storage	Contigency	S09: Financial activities insurances and related fees	361.7	USD/kWH2
Liquefaction and storage	Insurances	S09: Financial activities insurances and related fees	42.6	USD/kWH2
Liquefaction and storage	Owner Costs	S11: Other activities and services	191.5	USD/kWH2

Liquefaction and storage	Project management	S11: Other activities and services	63.8	USD/kWH2
Onshore wind	Nacelle	S03: Transformation industries	444.0	USD/kW
Onshore wind	Blades	S03: Transformation industries	180.0	USD/kW
Onshore wind	Tower	S03: Transformation industries	155.0	USD/kW
Onshore wind	Electrical balance of plants	S03: Transformation industries	133.0	USD/kW
Onshore wind	Construction (Civil works + Installation)	S05: Construction	189.0	USD/kW
Onshore wind	Transport	S07: Transport storage and post services	49.0	USD/kW
Onshore wind	Contingency and finance	S09: Financial activities insurances and related fees	49.0	USD/kW
Onshore wind	Project planning and management	S11: Other activities and services	38.0	USD/kW
Solar photovoltaics	Modules	S03: Transformation industries	369.0	USD/kW
Solar photovoltaics	Inverters	S03: Transformation industries	36.0	USD/kW
Solar photovoltaics	BoS hardware	S03: Transformation industries	129.0	USD/kW
Solar photovoltaics	Installation	S05: Construction	155.0	USD/kW
Solar photovoltaics	Contingency and fees	S09: Financial activities insurances and related fees	97.0	USD/kW
Solar photovoltaics	Land	S10: Real estate activities	3.0	USD/kW
Solar photovoltaics	Design and engineering	S11: Other activities and services	9.0	USD/kW
Solar photovoltaics	Other (PR, permitting, customer)	S11: Other activities and services	51.0	USD/kW

904

S5.2.3. *Impacts during the operation phase: introducing new industries*

906 Since green hydrogen production and liquefaction as well as green steel did not yet exist in the Ceará's
907 economy in 2018, these activities had to be inserted into the IOT. This is only needed for the operation
908 phase, since in the construction phase the change in final demand is limited to the existing sectors and
909 the new industries cannot start operation before construction being finalized.

910 As explained by Miller and Blair [59], this approach consists in introducing a new column and row for the
911 new sector in the technical coefficients matrix A, and hence, in the Leontief inverse L. This is done by
912 estimating the direct input coefficients of the new sector, that is, $\alpha_{i,n+k}$, where i = the existing sectors
913 in Ceará's economy and n+k is one of the k new sectors: renewable electricity for electrolysis (RE),
914 hydrogen production via alkaline electrolysis (GH2), hydrogen liquefaction and storage (LS), and green
915 steel production (GS). For instance, for $i=3$, $\alpha_{3,GH2}$ would represent the share of total expenditures from
916 the green hydrogen sector that are directed to sector 3, in this case the transformation industry.

917 Based on Equation 28, the direct technical coefficients are found by dividing the amount of domestic
918 sector i outputs required as inputs for the new sector ($z_{i,n+k}^D$) by the total outlay of the new sector (x_{n+k}).
919 This is done by allocating operational cost items (see Section S2.2) to specific economic sectors (see
920 Table S17). This ensures that the impact assessment is technology-specific.

921 Since not all inputs will be sourced from the local industry, total expenditures have to first be
922 disaggregated into domestic industry transactions and imports:

$$z_{i,n+k}^T = z_{i,n+k}^D + z_{i,n+k}^M \qquad\qquad\qquad \text{Equation 44}$$

923 where

924 $z_{i,n+k}^T$ is the total expenditure of the new industry k allocated to industry sector i

925 $z_{i,n+k}^D$ is the expenditure of the new industry k in the domestic industry sector i

926        $z_{i,n+k}^{M}$ is the expenditure of the new industry k allocated to industry sector *i* spent in imports

927 The shares of each investment component that is spent in Ceará is estimated via local content scenarios
928 (s). In these scenarios, local content shares (lcs_i) are used to separate total expenditures into domestic
929 expenditures and imports. The allocation of investment to each domestic industry sector *i* can be
930 calculated by

$$z_{i,n+k}^{D,s} = z_{i,n+k}^{T} * lcs_{i,n+k}^{S} \qquad \text{Equation 45}$$

931 where $lcs_{i,n+k}^{S}$ refers to the local content share for domestic sector *i*, according local content share
932 scenario *s*. Once $z_{i,n+k}^{D,s}$s determined, $a_{i,n+k}^{s}$ can be found by dividing $z_{i,n+k}^{D,s}$ for each productive sector *i*
933 by the total expenditure (x_{n+k}):

$$a_{i,n+k}^{s} = z_{i,n+k}^{D,s}/x_{n+k} \qquad \text{Equation 46}$$

934 Then the direct technical coefficients can be added to a new (*n+k*) x (*n+k*) technical coefficients matrix
935 $\bar{A}^s$, which will contain the *n* x *n* A matrix, $\alpha_{i,n+k}^{s}$ as the *n+k* column, and zeros as the *n+k* row block
936 representing sales the existing industries, since we assume no output of the new industries are used as
937 inputs for the existing domestic industry (i.e. export assumption):

$$\bar{A}^s = \begin{bmatrix} \alpha_{1,1} & \cdots & \alpha_{1,n} & \alpha_{1,n+1}^{s} & \cdots & \alpha_{1,n+k}^{s} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \alpha_{n,1} & \cdots & \alpha_{n,n} & \alpha_{n,n+1}^{s} & \cdots & \alpha_{n,n+k}^{s} \\ 0 & \cdots & 0 & \alpha_{n+1,n+1}^{s} & \cdots & \alpha_{n+1,n+k}^{s} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ 0 & \cdots & 0 & \alpha_{n+k,n+1}^{s} & \cdots & \alpha_{n+k,n+k}^{s} \end{bmatrix} \qquad \text{Equation 47}$$

938

939 The Leontief inverse for the operation phase for each local content scenario can be obtained through
940 Equation 48.

$$\bar{L}^{s} = (I - \bar{A}^s)^{-1} \qquad \text{Equation 48}$$

941 The total output of the new industries is sized to be the equivalent of their total sales, given the physical
942 input-output quantities required and the calculated levelized cost as the sales price, given assumptions
943 described in Section S2. Expenditures on intermediate inputs are allocated to (existing or new)
944 industries, expenditures on direct labor allocated to the salary income component of value added, and
945 the difference between the total sales and costs on intermediates and labor is allocated to gross
946 operating surplus (i.e., it is assumed to be capital remuneration). Balance for renewable electricity and
947 green hydrogen is ensured by assuming the entirety of the sales going to a single consuming industry:
948 renewable electricity only sells to green hydrogen industry and the green hydrogen industry only sells
949 to either the liquefaction and storage industry (in the green hydrogen exports scenario) or the green
950 steel industry (in the green steel exports scenario). This ensures that the total expenditures of these two
951 industries equal the expenditures necessary to produce the quantities required to ensure balance in the
952 system.

953 To isolate the impacts of the new industry sector, we let the change in final demand for the existing
954 sectors to be 0. In this case, as demonstrated by Miller & Blair[59], the final demand for the new sectors
955 will be equal to their total exports in each export scenario *t*. The vector of final demand can then be

$$\Delta\bar{f}^{O,s,t} = \begin{bmatrix} f_1^t \\ \vdots \\ f_n^t \\ f_{n+1}^t \\ \vdots \\ f_{n+k}^t \end{bmatrix} \qquad \text{Equation 49}$$

956

957 where

$$f_i^{O,s,t} = \begin{cases} 0, & \forall\, i = 1,2,\dots n \\ 0, & \forall\, i = RE, GH2 \\ x_i^{O,t}, & \forall\, i = LS, GS \end{cases}$$

<div align="right">*Equation 50*</div>

958

959 The final demand for renewable electricity and green hydrogen will equal zero since their exports are
960 zero in both scenarios: the entirety of production is being used by the new exporting sector (liquefaction
961 and storage or green steel). For the new exporting sectors, the final demand will equal the total exports
962 for the liquefaction and storage and the green steel sectors. Since liquefaction and storage and green
963 steel only sell products for exports, their total exports equals their total output. This will be either zero or
964 the total sales given prices and physical output quantities depending on the export scenario.

965 Then, the impact on output in the operation phase can be obtained by post-multiplying the augmented

966 Leontief inverse by the change in final demand due to exports.

$$\Delta x^{O,s,t} = \bar{L}^s \Delta \bar{f}^{O,s,t}$$

<div align="right">*Equation 51*</div>

967 *Table S17 - Sectoral allocation during operation phase, considering existing sectors only*

Technology	Cost item	Sector	Value	Unit
Battery	Maintenance	S03: Transformation industries	35.0	USD/kW
Green Steel	Iron ore pellets (ton)	S03: Transformation industries	192.0	USD/t
Green Steel	Natural gas (GJ)	S02: Extractive Industries	16.1	USD/t
Green Steel	Electricity (kWh)	S04: Electricity gas water and other utilities	42.9	USD/t
Green Steel	Carbon (kg)	S03: Transformation industries	6.1	USD/t
Green Steel	Lime (kg)	S03: Transformation industries	5.1	USD/t
Green Steel	Raw water withdrawal(ton)	S04: Electricity gas water and other utilities	2.4	USD/t
Green Hydrogen	Maintenance	S03: Transformation industries	21.8	USD/kWH2
Green Hydrogen	Water	S04: Electricity gas water and other utilities	3.4	USD/kWH2
Green Hydrogen	Insurance	S09: Financial activities insurances and related fees	10.9	USD/kWH2
Liquefaction and storage	Electricity	S04: Electricity gas water and other utilities	1.0	USD/kgH2
Liquefaction and storage	Gas terminalling	S04: Electricity gas water and other utilities	0.0	USD/kgH2
Onshore wind	Maintenance	S03: Transformation industries	18.0	USD/kW
Onshore wind	Operation	S04: Electricity gas water and other utilities	12.0	USD/kW
Onshore wind	Land lease	S10: Real estate	2.5	USD/kW
Solar photovoltaics	Maintenance	S03: Transformation industries	11.5	USD/kW
Solar photovoltaics	Operation	S04: Electricity gas water and other utilities	9.5	USD/kW

968 ### S5.2.4. *Endogenizing households*

969 Similarly to the introduction of a new industry, households are endogenized by adding a new row and
970 column to the technical coefficients matrix. By doing so, households become the *n+k+1* sector in the
971 input-output model, that is now formed by *n* existing productive sectors, k new green sectors (*n+k*) and
972 households (*n+k+1*). Following a similar approach as to Vasconcellos and Caiado Couto[34] and Vale and
973 Perobelli[62], coefficients for household salary remunerations (*hr*) and consumption (*hc*) are added as a
974 row and a column in the inter-industry technical coefficients matrix $\bar{A}^s$ to obtain a new technical
975 coefficients matrix with households endogenized ($\bar{\bar{A}}^s$):

$$\bar{\bar{A}}^s = \begin{bmatrix} \bar{A}^s & \bar{h}_c \\ \bar{h}_r & 0 \end{bmatrix}$$

<div align="right">*Equation 52*</div>

976

977 where

978     $\bar{h}_r$ is a row vector including household salary remuneration coefficients for the *n+k* productive sectors

979     $\bar{h}_c$ is a column vector including household consumption coefficients for the *n+k* productive sectors

980   These vectors include the household remuneration and consumption of the *n* existing sectors plus the
981   remuneration and consumption coefficients for the new sectors (Equation 53 and Equation 54).

$$\bar{h}'_r = [hr_1 \quad \cdots \quad hr_n \quad hr_{n+1} \quad ... \quad hr_{n+k}]$$ *Equation 53*

$$\bar{h}_c = [hc_1 \quad \cdots \quad hc_n \quad hc_{n+1} \quad ... \quad hc_{n+k}]$$ *Equation 54*

982   The vectors with the coefficients for household remunerations can be found by dividing the expenditures
983   with salaries by total expenditures (Equation 55). For existing sectors, these are calculated based on
984   total sectoral salary remuneration data from the RAIS database [26]. For the new industries, this is
985   calculated based on employment factors from the literature review (see Section S2.2) and the average
986   salary for the sector (by gender) reported in the RAIS.

$$hr_j = \frac{r_j}{x_j} \; \forall \, j = 1,2,...,n,n+1,...,n+k$$ *Equation 55*

987   Similarly, the coefficients for household consumption can be found by dividing household consumption
988   of each industry by total household remuneration (Equation 56).

$$hc_i = \begin{cases} \frac{c_i}{\sum_{j=1}^n r_j} \; \forall \, i = 1,2,...,n \\ 0 \; \forall \, i = n+1,...,n+k \end{cases}$$ *Equation 56*

989

990   where $c = [\, c_1 \quad \cdots \quad c_n\,]$ is the vector of household consumption of domestic sector *i* taken from the
991   industry-by-industry input output table and $\sum_{j=1}^n r_j$ is the total household income (salaries) associated to
992   the *n* productive sectors. The household consumption of the green sectors is considered to be 0, since
993   these are not final products.

994   The Leontief inverse for the model with households endogenized (the semi-closed model) can then be
995   obtained as in Equation 57.

$$\bar{\bar{L}}^s = (I - \bar{\bar{A}}^s)^{-1}$$ *Equation 57*

996   An extra row is added to the vector for the change in final demand to obtain $\bar{\bar{\Delta f}}^{O,t}$. The value for the
997   household sector is also set to 0, similarly to all other existing sectors.

$$\Delta \bar{\bar{f}}^{O,s,t} = \begin{bmatrix} \Delta \bar{f}^{O,s,t} \\ 0 \end{bmatrix}$$ *Equation 58*

998

S5.3.   Model outputs

1000   This section explains how value added, salary income, and employment effects are calculated based
1001   on their respective coefficients and output effects.

1002   Output effects are disaggregated into direct, indirect, and induced effects as follows. Total output effects
1003   in project phase *p* are obtained by the multiplication of the Leontief inverse and the change in final
1004   demand for that phase, as explained above. Direct output effects – or first round effects – are obtained
1005   by post-multiplying the identity matrix by the final demand vector. Indirect output effects are obtained by
1006   removing the direct effects from the total output obtained from the open model. Induced effects are the
1007   difference between the output effects from the semi-closed model (total effects) and the indirect
1008   effects[59,62].

$$\Delta x^{1 \text{TOTAL},p,s,t} = \bar{\bar{L}}^{p,s} \Delta \bar{\bar{f}}^{p,s,t}$$ *Equation 59*

$$\Delta x^{1 \text{DIRECT},p,s,t} = I^{p,s} \Delta f^{p,s,t}$$ *Equation 60*

$$\Delta x^{1 \text{INDIRECT},p,s,t} = \bar{L}^{p,s} \Delta \bar{f}^{p,s,t} - \Delta x^{1 \text{DIRECT},p,s,t}$$ *Equation 61*

$$\Delta x^{1^{\text{INDUCED,p,s,t}}} = \Delta x^{1^{\text{TOTAL,p,s,t}}} - \Delta x^{1^{\text{INDIRECT,p,s,t}}}$$

Equation 62

1009   *S5.3.1. Value-Added*

1010   Following Miller and Blair[59], a vector of value added coefficients w'_c can be found by dividing the value
1011   added in each sector *j* by the sector *j* gross output:

$$w_{c_j} = \frac{w_j}{x_j} \ \forall j = 1,2,\dots,n,n+1,\dots,n+k$$

Equation 63

1012   For the new industries, the industry value added is calculated based on the expenditures on salaries for
1013   direct labor and on the expected gross operating surplus assuming the sales price equals the levelized
1014   cost of the commodity. That is, the difference between the total revenues (calculated as the physical
1015   quantity sold times the levelized cost) and the expenditures on intermediates plus labor is allocated to
1016   gross operating surplus.

1017   The vector of change in total value added generated in sector *j* can then be found by multiplying the
1018   value added coefficients by the change in sectoral output in sector *j*:

$$\Delta w^1 = \widehat{w'}_c \, \Delta x^1 = \begin{bmatrix} w_{c1}\Delta x_1^1 \\ \vdots \\ w_{cn}\Delta x_n^1 \\ \vdots \\ w_{cn+k}\Delta x_{n+k}^1 \end{bmatrix}$$

Equation 64

1019

1020   The disaggregation of total value added effects can then be done in similar way was for output effects.

1021   *S5.3.2. Employment and income*

1022   Impact on employment and income are calculated by pre-multiplying the total requirements matrices by
1023   employment and salary income coefficient vectors to obtain the employment-generation (E) and income-
1024   generation (R) matrices, respectively. The vector of income coefficients is $\bar{\bar{h}}'_r$, or the last row of the
1025   direct coefficient matrix $\bar{\bar{A}}^s$, as defined in the previous section. The vector of employment coefficients $\bar{e}'_c$
1026   is determined in the same way as $\bar{\bar{h}}'_r$, but with total employment in number of employees from the RAIS
1027   data instead of salaries in dollar-worth values.

$$\bar{E}^s = \widehat{\bar{e}'}_c \bar{L}^s$$

Equation 65

$$\bar{\bar{E}}^s = \widehat{\bar{\bar{e}'}}_c \bar{\bar{L}}^s$$

Equation 66

$$\bar{R}^s = \widehat{\bar{h}'}_r \bar{L}^s$$

Equation 67

$$\bar{\bar{R}}^s = \widehat{\bar{\bar{h}'}}_r \bar{\bar{L}}^s$$

Equation 68

1028

1029   The direct, indirect, and induced effects on employment and income can then be found by using the
1030   diagonal of the vector of direct employment and income coefficients instead of A and by replacing L by
1031   E and R, respectively.

1032   Finally, the impacts on employment are disaggregated by gender. This is done by taking the share of
1033   each gender (male and female) in total occupation and in total remunerations of each sector in the RAIS
1034   data and then multiplying the employment and income effects by these shares. Gender shares for the
1035   new green industries are assumed to be the same of their closest existing industry (e.g., existing Iron
1036   and Steel for green steel, existing energy sector for renewable electricity, etc).

S6.   Supplemental results

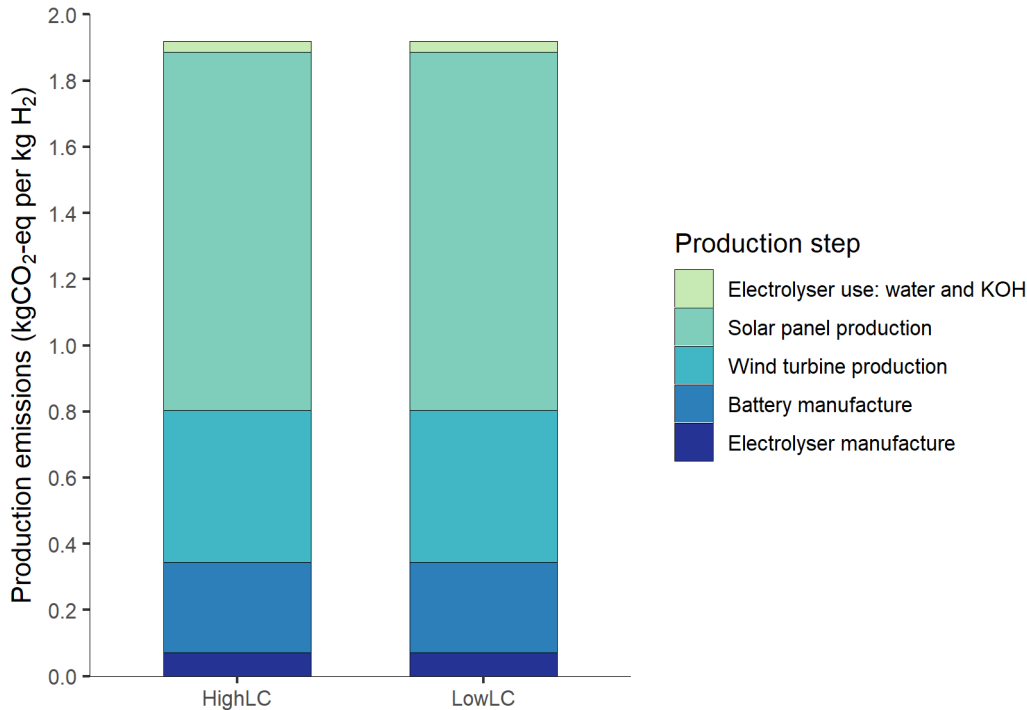## S6.1.   Hydrogen production emissions by production step

Figure S5 - Greenhouse gas emissions associated with green hydrogen production (in kgCO2-eq per kg H2) in the high local content (HighLC) and the low local content (LowLC) scenario.

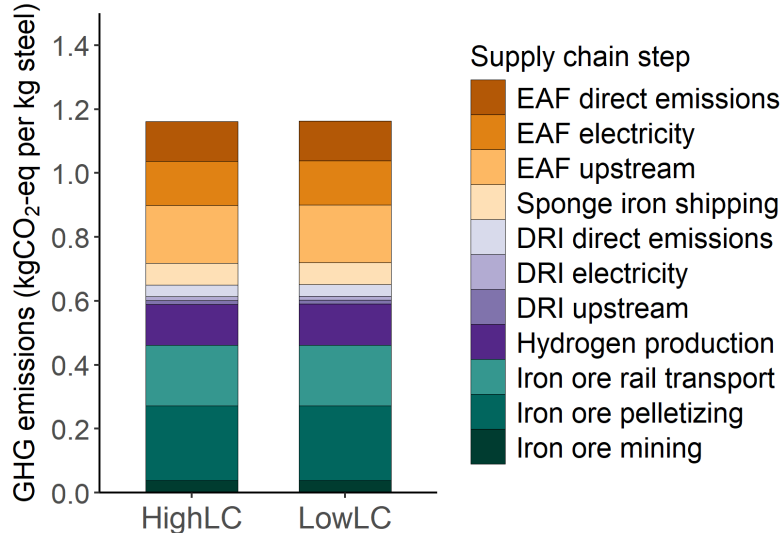## S6.2.   Results from sensitivity analysis on sponge iron export

Figure S 6 - Climate impacts of green steel production, disaggregated by supply chain step for the sensitivity analysis scenario of sponge iron export. Climate impacts are shown in kgCO₂eq per kg steel. In the sponge iron export scenario, steps include hydrogen production in Ceará, iron ore mining in the Carajás mine, pelletizing, rail transport to Ceará, hydrogen-based direct reduction of iron ore (DRI) to produce sponge iron in Ceará, shipping of sponge iron followed by electric arc furnace (EAF) steelmaking in Ijmuiden. The high local content (HighLC) scenario, using North-East Brazillian electricity for manufacturing of wind turbines, results in 0.1% lower emissions than the low local content (LowLC) scenario, which uses the global electricity mix.

LCOS in sponge iron export scenario

1051
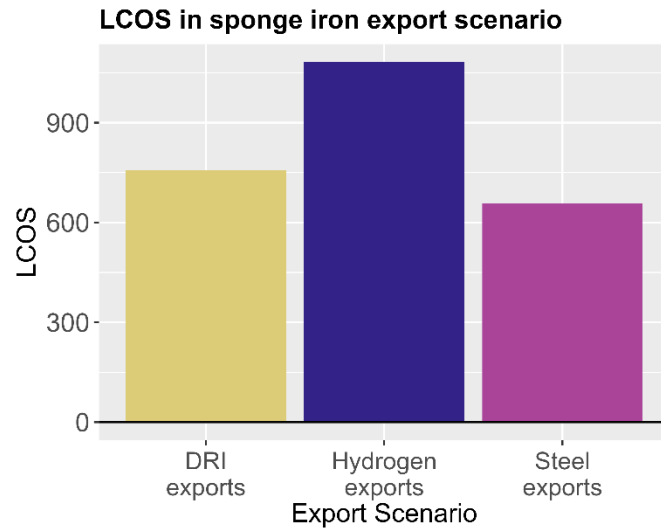
Figure S7 - Cost results for the sensitivity analysis of exporting sponge iron. For employment data, it was assumed that 50% of workers would work at the DRI plant while 50% of workers would work at the EAF plant.

1054
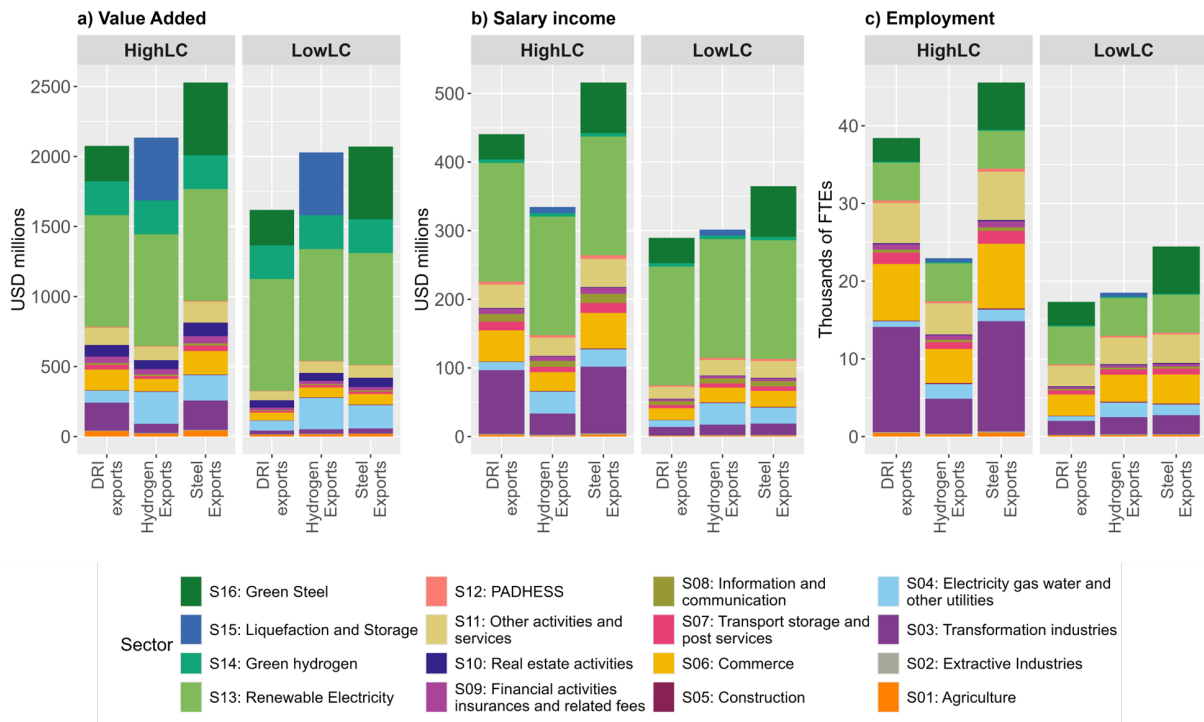
Figure S8 - Socioeconomic impacts of the sponge iron export scenario. For employment data, it was assumed that 50% of workers would work at the DRI plant while 50% of workers would work at the EAF plant.

S6.3.   Results from sensitivity analysis on technoeconomic assumptions

Energy prices tend to fluctuate over time. Grid electricity prices in the base year were 78 USD/MWh in Brazil[42] and 73 USD/MWh in the Netherlands[48]. Grid electricity prices in 2023 increased to 103 USD/MWh in Brazil[63] and to 261 USD/MWh in the Netherlands[48]. If these prices are taken into account, then the LCOS in the green steel exports scenario becomes 671 USD/t steel and the LCOS in the green hydrogen exports scenario becomes 1207 USD/t steel. Here, the green steel produced in IJmuiden would hence be 80% more expensive than the green steel produced in Ceará and then transported to IJmuiden (Table S19).

Regarding hydrogen transport costs, the default case assumed the average value from IRENA[41] estimates. The lower and upper bound of IRENA estimates for hydrogen transport costs would lead to a LCOS in the green hydrogen export scenario of 907 USD/t steel and 1206USD/t steel, respectively. This means costs in the hydrogen export scenario would be 50-83% higher than in the green steel export scenario(Table S19).

The weighted average cost of capital (WACC) impacts the sales price of commodities as it influences the amount of surplus needed to compensate for the initial capital investments, impacting the levelized cost. As such, it impacts industry output, and also total value added via the gross operating surplus component, as expenditures in intermediate inputs and labor remain constant. However, the WACC varies with economic climate and perceived risk.

Therefore, we model a change of the WACC for the levelized cost of green hydrogen (LCOH), liquefaction and storage of green hydrogen (LCOLS), and green steel production (LCOS) from 10% (default assumption) to 6% (low WACC) and 12% (high WACC) (Table S18). We do not model the effect on the levelized cost of energy since renewable electricity is a more mature activity than the others and the renewable electricity price and quantity are the same for all scenarios, not impacting the *difference* between the export scenarios. The results for the LCOS under different WACC assumptions are summarized in Table S19.

Table S18 – LCOH and LCOLS under different WACC assumptions

Levelized cost	Low WACC (6%)	Default (10%)	High WACC (12%)
LCOH	3.96 USD/kgH2	4.17 USD/kgH2	4.28 USD/kgH2
LCOLS	2.06 USD/kgH2	2.49 USD/kgH2	2.72 USD/kgH2

Table S19 - Summary of results for the levelized cost of steel (LCOS) according to different sensitivity analysis cases and production locations

Sensitivity analysis case	Co-locating green steel production in Ceará (Steel exports)	Locating green steel production in the Netherlands (Hydrogen exports or DRI exports)	NL/CE	Co-location savings	Difference to default Steel export	Difference to default H2 export
Default	658	1082	164%	-39%	100%	100%
H2 replacing natural gas	695	1164	167%	-40%	106%	108%
DRI	658	758	115%	-13%	100%	70%
Energy crisis	671	1207	180%	-44%	102%	112%
TranspHigh	658	1205	183%	-45%	100%	111%
TranspLow	658	987	150%	-33%	100%	91%
RealDevaluation	655	1082	165%	-39%	100%	100%
All WACC 6%	610	661	108%	-8%	93%	61%
All WACC12%	685	1341	196%	-49%	104%	124%
WACC different (CE 10%, NL 6%)	658	688	105%	-4%	100%	64%
WACC different (CE 12%, NL 6%)	685	703	103%	-3%	104%	65%
Energy+Transp	671	1308	195%	-49%	102%	121%
WACC different + TranspLow	685	628	92%	9%	104%	58%
WACC different + DRI	685	743	108%	-8%	104%	69%

Figure S9 shows that whenever both liquefaction and storage and green steel production have the same WACC, the calculated value added from green steel is slightly higher than that of liquefaction and storage. The only two situations where liquefaction and storage would have a

1089 higher impact on value added would be 1) when green hydrogen is used to replace natural gas in
1090 green steel production, leading to a lower green steel output for a given green hydrogen production
1091 and 2) if liquefaction and storage has a higher WACC than green steel, leading to higher value
1092 added impacts.

1093 Note, however, that changes in the WACC only affect value added impacts and not employment
1094 and salary income as it changes only the gross operating surplus component of the expenditures
1095 (Figure S10and Figure S11). Employment and salary income effects are impacted by changes in
1096 direct employment expenditures, which can reflect a different employment factor (i.e., number of
1097 jobs per unit of output) or a salary that is higher or lower than the default assumption. For
1098 employment and salary income, green steel consistently outperforms liquefaction and storage.
1099 Even if the employment in liquefaction and storage was +40% higher and employment in green
1100 steel was –40% lower than the default assumption, direct employment in green steel would be
1101 more than double of that in liquefaction.

1102 Under the default case, approximately half of the iron ore pellets are assumed to be sourced from
1103 local firms in the HighLC. If all iron pellets are processed by local firms (PelletDom), employment
1104 effects for the green steel exports scenario could increase by up to 50% in the operation phase. If
1105 all iron pellets are fully imported in the HighLC (PelletImp), with only wind turbines and
1106 electrolyzers still being sourced domestically, employment effects could decrease by 25% in the
1107 operation phase in the green steel exports scenario. If iron pellets are fully imported, the
1108 difference between HighLC and LowLC also decreases, as only wind turbines and electrolyzers
1109 are included in the local content scenarios. The full imports of iron pellets also reduces the
1110 difference between the two export scenarios, since iron pellets are only used in the green steel
1111 exports scenario. This indicates that localizing iron pellets production could significantly increase
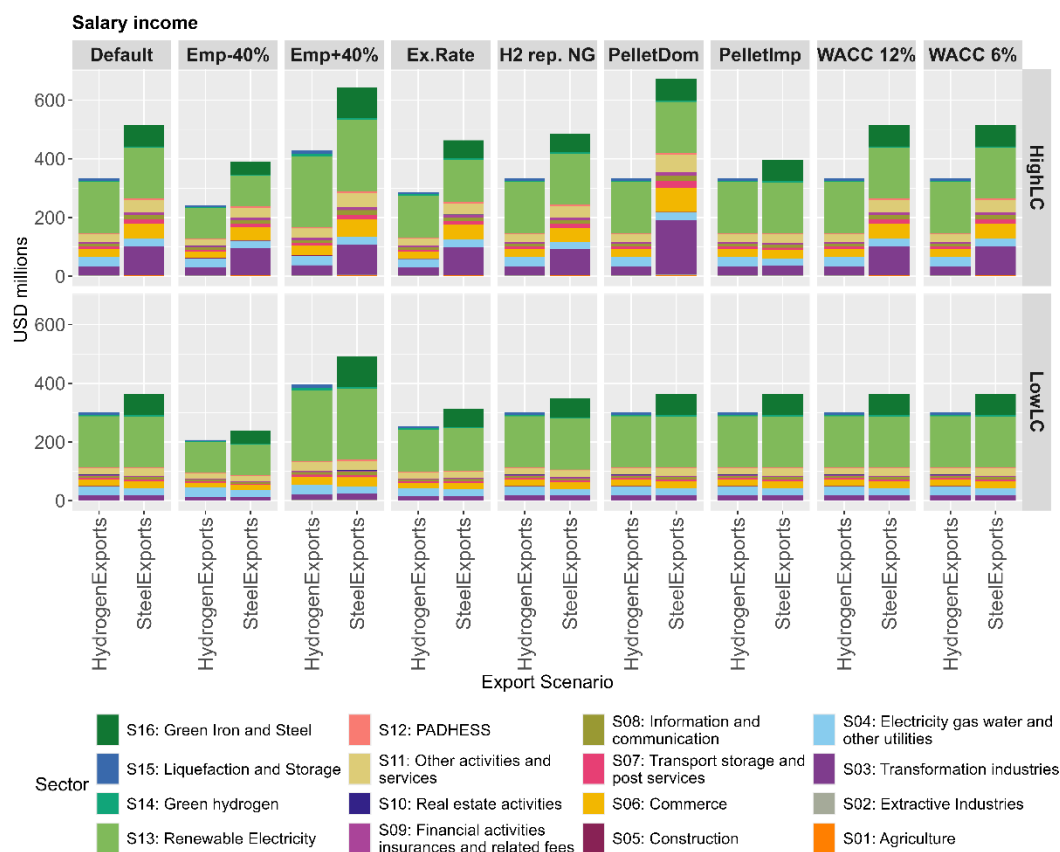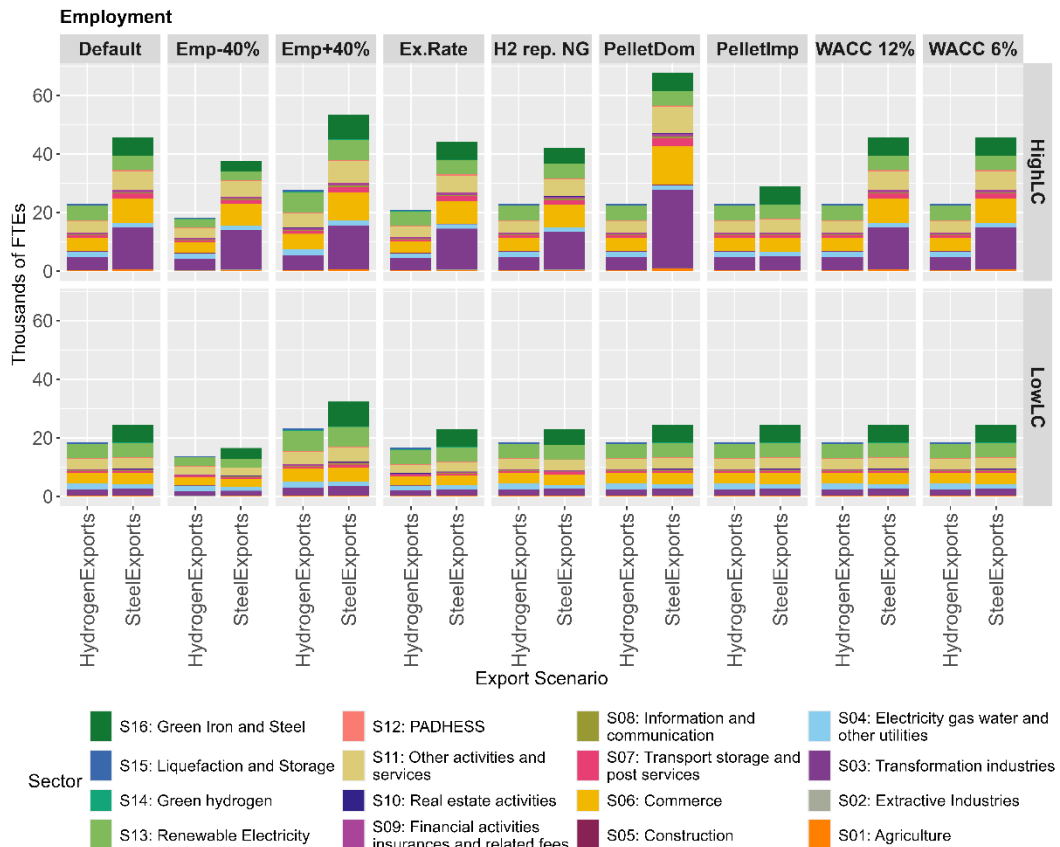1112 the difference between the high and low linkage scenarios.

1113
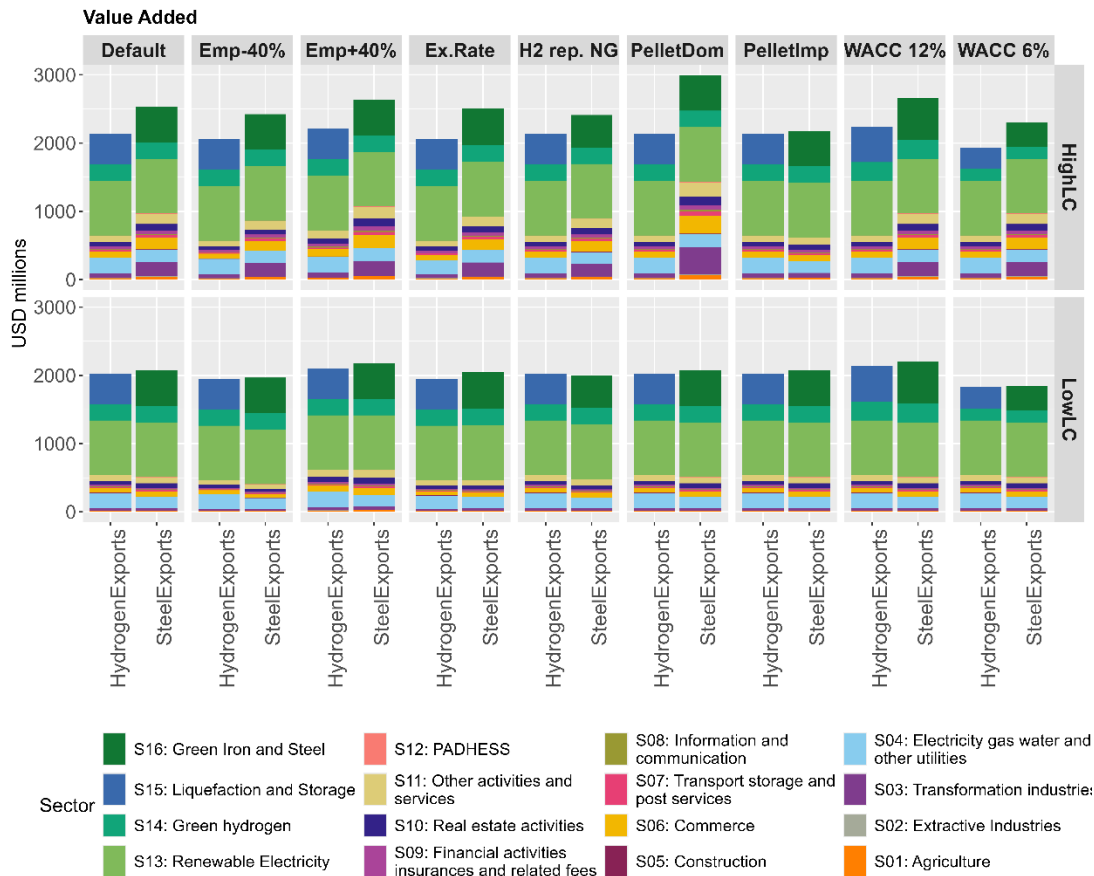
1114 *Figure S9 - Sensitivity analysis results for impacts on value added*

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Salary income

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1116 *Figure S10- Sensitivity analysis results for impacts on salary income*

Employment

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1118 *Figure S11 - Sensitivity analysis results for impacts on employment*

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