Supplementary Materials

Supplementary Table 1. Basis and Comparability of Headline Quantitative Claims Cited in This Review

Claim	Value	Source Study	System boundary	Key assumptions
Emissions reduction (lower bound)	45%	25	Cradle-to-gate, SMR + CCS, Escalante facility	≥95% capture rate; U.S. facility context
Emissions reduction (upper bound)	76%	16	Well-to-wheel, oil-sands fuel substitution	Assumes full blue-hydrogen substitution of natural gas fuel in oil-sands operations
Carbon price – profitability threshold	$99/t	16	Facility-level breakeven analysis	Oil-sands decarbonization specific; not a general competitiveness threshold
Carbon price – MAC turns negative	$300/t	23	Economy-wide MAC-curve model, Alberta	Hydrogen-natural gas blending only; not directly comparable to breakeven price
Storage capacity	>1.9 Gt	11	Nisku/Wabamun saline aquifers, theoretical in-place capacity	Deployable capacity constrained by injectivity, monitoring, and pressure limits (Section 4)

Supplementary Table 2. Methane-Leakage Assumptions and Sensitivity Across Reviewed Studies

Study	Assumed/estimated leakage rate	Estimation approach	Resulting carbon-intensity implication
20	<1% (condition for meaningful net-zero contribution)	Policy-analytic threshold, not directly measured	Carbon intensity <4 $kgCO_2e/kgH_2$ achievable at capture >90%
18	0.3–1.5% (sensitivity band)	Bottom-up, LCSA inventory-based	Carbon intensity varies within LCSA-reported range across the band
25	Default EPA/GHGRP inventory factors	Bottom-up, inventory-based	11.99 → 6.59 $kgCO_2e/kgH_2$ with capture; leakage not independently varied
Cross-study synthesis	–	–	Leakage >3–4% negates blue hydrogen's climate advantage over unabated natural gas

Supplementary Table 3. Basis and Comparability of Reported Economic Values

Value	Type	Technology/Geography	Method
$3.28–$3.33/kg (21)	Levelized production cost (LCOH)	ATR/SMR greenfield plant, Saskatchewan	Techno-economic analysis (TEA)
$1.82–$3.22/kg (pre-incentive) (25)	Levelized production cost (LCOH)	SMR + CCS, Escalante facility, U.S.	TEA + life cycle carbon accounting
$99/t CO_2 (16)	Breakeven/profitability carbon price	Oil-sands fuel substitution, Alberta	Facility-level breakeven analysis
$300/t CO_2 (23)	Marginal abatement cost (turns negative)	Economy-wide hydrogen-blending, Alberta	MAC-curve energy-systems modelling

Supplementary Table 4. Reported Lifecycle GHG Performance of Grey, Blue, and Green Hydrogen Pathways in the Reviewed Literature

Hydrogen pathway	Configuration / energy source	Reported GHG intensity	Scope/important assumption	Source in this review
Grey hydrogen	SMR without CCS	11.99 $kgCO_2e/kgH_2$	Unabated SMR configuration; study-specific LCA	25
Blue hydrogen	SMR + CCS	6.59 $kgCO_2e/kgH_2$	≥95% CO_2 capture; same study/model as unabated SMR	25
Blue hydrogen	ATR + CCS	No single cross-study GHG value reported here	91% capture; no-grid-electricity configuration; strongest overall environmental performance in 7/9 categories, although not lowest climate-change impact	18
Green hydrogen	Alkaline electrolysis + solar PV	2.3–4.3 $kgCO_2e/kgH_2$	Value reported in reviewed LCA synthesis; dependent on PV/electrolyzer assumptions	56
Green hydrogen	Water electrolysis + solar PV	2–7 $kgCO_2e/kgH_2$	Reported lifecycle range; system assumptions differ from other pathways	56
Green hydrogen	High-temperature water-vapour electrolysis + nuclear	≈2.0 $kgCO_2e/kgH_2$	Includes nuclear power-plant emissions	56
Green hydrogen	Thermochemical water splitting + solar	1.02 $kgCO_2e/kgH_2$	Technology-specific result; not directly comparable to conventional electrolysis	56
Green hydrogen	Water electrolysis + wind	0.0418 kg CO_2/kgH_2	Electrolysis-process emissions only; not a full lifecycle value	56
Green hydrogen	Alkaline electrolysis + wind	Lowest climate-change impact among pathways assessed	Alberta-specific LCSA; numerical value should not be inferred without the study's full inventory/result table	18

**Values are reported as presented in the reviewed studies and should not be interpreted as directly comparable pooled estimates. Differences in system boundaries, electricity mixes, technologies, upstream natural-gas emissions, capture rates, geographical settings, and lifecycle inventories materially affect reported GHG intensities. Hamed et al. [52] synthesize values originating from different underlying LCA studies; therefore, the reported green-hydrogen values represent technology- and energy-source-specific estimates rather than a single universal carbon-intensity range. The 0.0418 kg CO_2/kgH_2 wind-electrolysis value represents process-stage emissions and is not directly*

comparable with full lifecycle estimates. Hannouf et al. [14] provides Alberta-specific comparative evidence demonstrating the strong influence of grid electricity and pathway configuration.

Supplementary Table 5. Canada's CCUS Hub Development Status and Capacity

CCUS Hub/Project	Province	CO_2 Capture Capacity (Mt/year)	Storage Type	Operational Year	Status
Alberta Carbon Trunk Line (ACTL)	Alberta	1.8	Deep Saline Aquifer	2020	Operational
Quest Project	Alberta	1	Deep Saline Formation	2015	Operational
Heartland Petrochemical Complex	Alberta	2.7	ACTL Pipeline	2025	Development
Weyburn-Midale	Saskatchewan	2.8	EOR (Enhanced Oil Recovery)	2000	Operational
Boundary Dam	Saskatchewan	1	EOR + Deep Saline	2014	Operational
Cascade Power Project	Alberta	3	Deep Saline Aquifer	2028 (Target)	Feasibility

(Data Taken From: Natural Resources Canada. (2024). Canada's carbon management strategy. Government of Canada)

Supplementary Table 6. Policy and Regulatory Framework for CCUS and Blue Hydrogen in Canada

Policy	Jurisdiction	Description	Policy Year/Vintage	Status (as of August 2026)	Impact on Blue Hydrogen
Carbon Pricing	Federal	$95/tonne → $115/tonne	2026 (base rate) rising to 2030 (scheduled)	Enacted; 2026–2029 schedule legislated under the Greenhouse Gas Pollution Pricing Act	High – drives economic viability
Clean Fuel Regulations	Federal	Low-carbon fuel standard (12% reduction)	2022 (regulation effective) targeting 2030	Enacted (2022)	Medium – creates H_2 demand

Investment Tax Credit	Federal	37.5% to 60% for CCUS projects	2022 (federal budget)	Enacted (2022 federal budget); rates as of 2026	High – reduces capital cost
Hydrogen Strategy	Federal	$1.5b funding; production targets	2020 (strategy released) targeting 2030	Enacted strategy; 2030 production targets are policy goals, not legislated	High – policy support
Technology Innovation and Emission Reduction (TIER)	Alberta	Performance-based emission standards	2020 (regulation effective; amended since)	Enacted (provincial regulation)	Medium – compliance pathway
Carbon Capture Incentive	Alberta	$75m/year funding program	2020 (program launched)	Enacted; ongoing funding program	High – direct incentive
Saskatchewan CCUS Credit	Saskatchewan	Provincial tax credit for CCUS	2021	Enacted	Medium – cost
Net-Zero Emissions Accountability Act	Federal	Legally binding 2050 target	2021 (Act passed); interim target 2030	Enacted (legislated Act)	High – long-term certainty
Strategic Innovation Fund	Federal	$8b for clean technology projects	2021 (fund active)	Enacted; ongoing R&D support program	Medium – R&D support
Canada Growth Fund	Federal	$15b for low-carbon investments	2022 (established)	Enacted; still in early stages of deployment as of 2026	High – project financing

(Natural Resources Canada. (2024). Canada's carbon management strategy. Government of Canada. https://natural-resources.canada.ca/energy-sources/carbon-management/canada-s-carbon-management-strategy)

Supplementary Table 7. Comparative Analysis of Major Canadian Blue Hydrogen Projects

Project	**Location**	**Production Capacity (tonnes H_2/day)**	**CO_2 Capture (Mt/year)**	**Capital Cost ($M)**	**Status**	**Key Features**
Air Products Edmonton	Alberta	1500	3	1600	Under Construction	Net-Zero facility, liquid H_2
ATCO Clean Energy Hub	Alberta	300	1.5	1300	Planning	Integrated with Renewables

Suncor Base Plant	Alberta	800	3	900	Feasibility	Oil Sands Integration
Pembina Redwater Complex	Alberta	250	1	500	Development	ACTL Connection
Capital Power Genesse	Alberta	400	1.8	800	Feasibility	Power-to-H_2 hybrid

(Data Taken from:Government of Alberta. (2026). Hydrogen roadmap. Government of Alberta. https://www.alberta.ca/hydrogen-roadmap

Natural Resources Canada. (2024). Canada's carbon management strategy. Government of Canada. https://natural-resources.canada.ca/energy-sources/carbon-management/canada-s-carbon-management-strategy)

Supplementary Table 8. Barriers and Enabling Success Factors for Blue Hydrogen Deployment in Canada.

Parameters	Barriers	Enabling Factors
Technical	• Methane leakage in supply chain • CO_2 transport infrastructure gaps • Long-term storage verification • H_2 pipeline material challenges	• Mature SMR/ATR technology • Proven geological storage sites • Advanced capture technologies (>90%) • Existing industrial expertise
Economic	• High capital cost • Uncertain carbon price • Competition from green hydrogen • Limited demand certainty	• Federal Investment Tax Credits (37.5-60%) • Established natural gas infrastructure • Growing industrial demand • Export market opportunities
Policy and Regulatory	• Interprovincial coordination gaps • Unclear long-term liability frameworks • Permitting complexity • Lack of H_2 standards	• Federal hydrogen strategy • Carbon pricing mechanisms • Clean fuel regulations • Net-zero 2050 commitment
Social and Environmental	• Public acceptance • Indigenous community concerns • Land use conflicts • Environmental justice issues	• Job creation potential • Regional economic development • Emission reduction benefits • Energy security enhancement

Infrastructure and Market	• Limited H_2 pipeline network • Port/export capacity constraints • Uncertain H_2 demand growth • Price volatility	• Extensive natural gas network • Strategic geographic location • Growing industrial decarbonization needs • Export opportunities