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Carbon intensity of blue hydrogen production

Accounting for technology and upstream emissions

Jan Gorski, Tahra Jutt, Karen Tam Wu | August 2021 (revised)

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Introduction

As Canada considers pathways to net-zero emissions by 2050, *blue hydrogen* — hydrogen gas derived from natural gas with carbon capture, utilization and storage (CCUS) — is receiving significant interest as an energy carrier. There are many competing claims about the climate benefits of blue hydrogen. This is partly because differences in production methods, technology choices, gas supply, energy requirements, and carbon capture rates lead to different estimates of emissions. As well, because blue hydrogen is created from fossil fuels, the emissions associated with the production and transportation of the fossil fuel source must also be included in its emissions profile.

In this paper we examine the emissions associated with blue hydrogen over the full life cycle, and the potential contribution and limits of CCUS technologies to decrease production emissions.

Blue hydrogen production

The main technology that has traditionally been used to produce blue hydrogen is steam methane reforming. However, companies are now pursuing autothermal reforming as a more cost-effective means to mass produce hydrogen. Both these processes separate hydrogen from the natural gas (methane) to produce syngas that can be further separated into hydrogen and carbon dioxide.

> **Steam methane reforming** (SMR) uses steam to separate the hydrogen from natural gas.[1] Most SMR facilities in current operation produce hydrogen for use as a feedstock to other processes such as oil refining, fertilizer, or chemical production.

[1] Global Syngas Technologies Council, "Steam-Methane Reforming." https://globalsyngas.org/syngas-technology/syngas-production/steam-methane-reforming/

Auto-thermal reforming (ATR) is a commercial technology commonly used in the production of ammonia and methanol.[2] ATR is now being proposed as a preferred technology to produce pure hydrogen from natural gas because it allows capture of carbon at higher rates than conventional SMR, at lower cost.[3] Compared to SMR, ATR has a simpler production stream, with a high concentration of carbon dioxide. This makes it easier to capture a higher percentage of carbon emissions in the conversion process.[4]

With blue hydrogen, the amount of carbon captured and stored from the production process is a key factor in the carbon intensity of the hydrogen produced. CCUS is discussed in greater detail below.

Life cycle GHG emissions of blue hydrogen

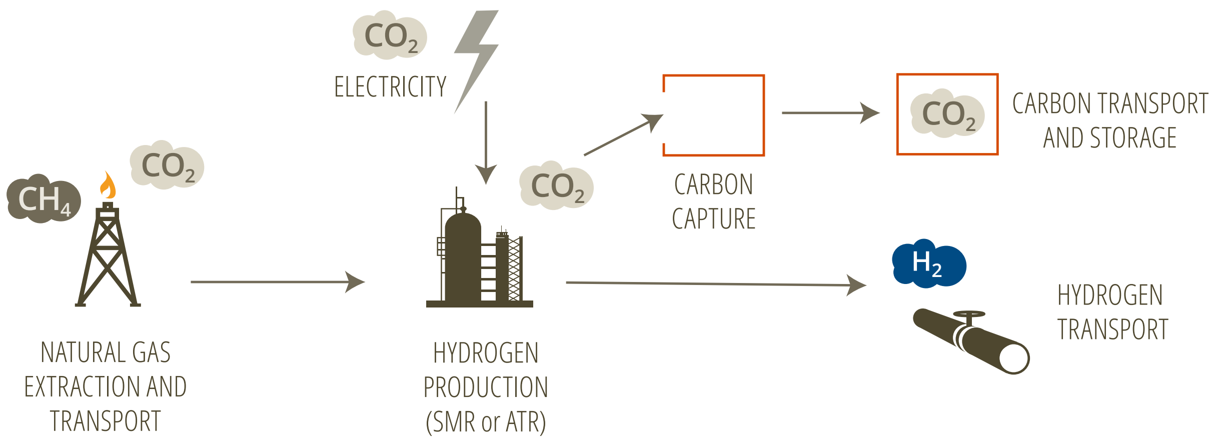

Figure 1. Blue hydrogen production process

An accurate estimate of the carbon footprint associated with hydrogen production from natural gas requires accounting for the various sources of emissions from well to point of use. The full life cycle emissions include all the emissions from all energy expended from:

- the construction and decommissioning of facilities for hydrogen production and carbon capture (negligible for blue hydrogen)
- the extraction and transportation of natural gas (upstream emissions)
- the hydrogen production process (e.g. SMR or ATR)

[2] Global Syngas Technologies Council, "Auto-Thermal Reforming." https://globalsyngas.org/syngas-technology/syngas-production/auto-thermal-reforming/

[3] Hydrogen Council, *Path to hydrogen competitiveness: A cost perspective* (2020), 21. https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

[4] S. Assabumrungrat and N. Laosiripojana, "Fuels — Hydrogen Production: Autothermal Reforming," *Encyclopedia of Electrochemical Power Sources* (Elsevier Science, 2009). https://www.sciencedirect.com/topics/engineering/autothermal-reforming

- the carbon capture process including capture, transport, and storage

Upstream emissions

Emissions associated with producing, processing, and transporting natural gas — known as upstream emissions — are also a significant contributor to the carbon intensity of blue hydrogen production. The source of these emissions is methane vented or leaked during production, processing, and transport, and fuel burned to power engines, compressors, boilers, and heaters. These emissions vary based on the composition of gas found in different natural gas reservoirs, the amount of gas processing required, the ratio of natural gas to electric power used in the process and transport of gas, and the carbon intensity of the electricity that is used. They can also vary significantly depending on the amount of methane leaked and vented in the process and the stringency of regulations at a regional level that prevent methane emissions.

Hydrogen production process and carbon capture rates

Both SMR and ATR produce similar levels of carbon emissions during the chemical reactions that separate the hydrogen from the methane molecule in both processes. However, with SMR, typically only about 60% of the carbon is contained in the process gas stream; the remaining 40% is in the flue gas (exhaust gas) where it is less concentrated.[5] SMR plants in operation today do not capture carbon from this flue gas stream. The carbon intensity of hydrogen produced from existing facilities is sometimes reported as the percent of the process carbon that is captured, rather than a percentage of the total carbon emissions from the hydrogen plant (see Figure 2, below).

Carbon capture rates of 90% have been demonstrated but have not yet been applied to the production of hydrogen by SMR.[6] This is because existing blue hydrogen production is integrated into refineries and ammonia plants — facilities where the end product is not hydrogen. As a result, the design of the plant is specific to the application. These existing integrated hydrogen plants were retrofitted to capture carbon and are not representative of what can be achieved at new hydrogen production plants designed to produce hydrogen as a commercial fuel. The Polaris project proposed by Shell aims to capture more than 90% of the CO_2 emissions related to hydrogen production in the Scotford refinery hydrogen plants.[7]

[5] *Path to hydrogen competitiveness*, 21.

[6] 90% was demonstrated at the Petra Nova coal powered electricity plant demonstration project in Texas. NRG Energy, "Petra Nova: Carbon capture and the future of coal power." https://www.nrg.com/case-studies/petra-nova.html

[7] Shell, "Shell proposes large-scale CCS facility in Alberta," news release, July 13, 2021. https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2021/shell-proposes-large-scale-ccs-facility-in-alberta.html

Conversely, carbon emissions associated with ATR process are nearly entirely contained within the process gas stream and are at a higher concentration. ATR plants can therefore more easily achieve higher capture rates at a lower cost compared to SMR at full scale production.[8] Two currently proposed ATR plants both have target capture rates of 95%.

If an SMR facility with CCUS captures 80% of its carbon process stream — but only about 60% of carbon is emitted in the process stream — it captures only 48% of the total carbon produced (see Figure 2).

Carbon capture process

The energy required to operate the carbon capture plant can be a significant source of emissions depending on its source. An ATR plant with carbon capture typically requires more electricity than an SMR plant. Using low-carbon electricity can reduce the emissions associated with the energy penalty.

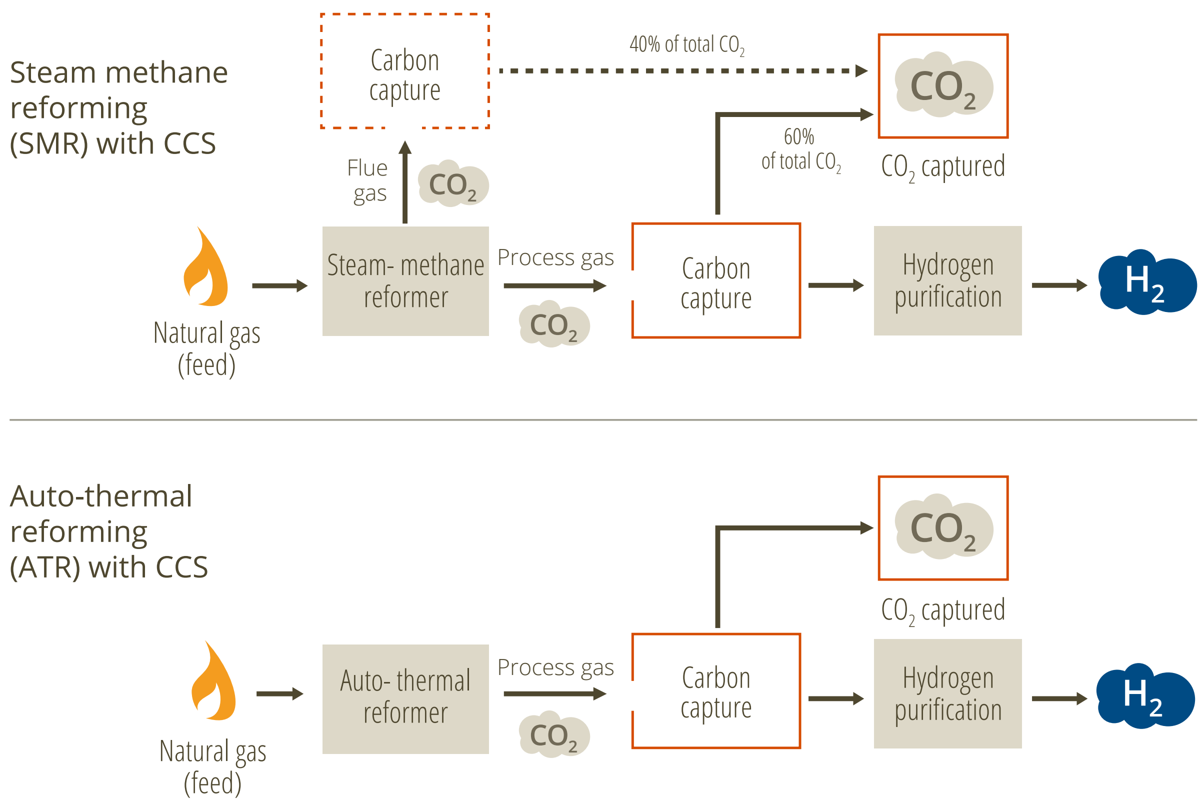

Figure 2. Carbon capture opportunities in hydrogen production

In an SMR facility (top), typically only around 60% of total carbon emissions from the facility are from the process stream; the remainder are in the flue gas and may not be captured.

[8] *Path to hydrogen competitiveness*, 21.

Carbon capture, utilization and storage

CCUS at a glance

Carbon capture, utilization and storage (CCUS) is a process by which carbon dioxide emissions produced from the combustion of fossil fuels (combustion emissions), or from the industrial processes themselves (process emissions) are separated from other gases and stored underground. The three main types of carbon capture technology are pre-combustion, post-combustion and oxyfuel combustion. Capture technologies are generally categorized by the method used to separate CO_2 from the gas stream. The five broad categories are liquid solvent, solid absorbent, membrane, solid looping, and inherent CO_2 capture. In total there are 25 separate technologies encompassing the five categories.[9]

Carbon capture, utilization and storage is a tool to lower the carbon emissions from hydrogen production. CCUS is a process by which CO_2 emissions produced from the combustion of fossil fuels (combustion emissions) or from the industrial processes themselves (process emissions) are separated from other gases. The CO_2 is then compressed, transported via pipelines, and injected deep underground for permanent storage. The separated and purified carbon can also be utilized in the manufacture of other products.[10]

To date, CCUS has mainly been used to reduce emissions from power generation (using coal/natural gas), natural gas processing, refining and upgrading, and chemical and fertilizer production. Around the world, there are 26 CCUS plants in operation, of which three are associated with hydrogen production.[11]

The carbon capture rate is one of the key determinants of the carbon intensity of blue hydrogen. To make hydrogen that can be part of a climate solution, production processes require carbon capture systems that deliver high capture rates. Capture rates of 95% are technically possible and have been proposed at new facilities.[12] However, no plants in current commercial operation demonstrate these maximum capture rates.

[9] Global CCS Institute, *Technology Readiness and Costs of CCS* (2021). https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCS-Tech-and-Costs.pdf

[10] Canada is home to 27 of the world's 181 carbon utilization projects and well placed to be a leader in this field. See: *The Carbontech Innovation System in Canada* (Pembina Institute, 2020). https://www.pembina.org/pub/carbontech-innovation-system-canada

[11] Global CCS Institute, *Global Status of CCS 2020,* 19. https://www.globalccsinstitute.com/wp-content/uploads/2020/12/Global-Status-of-CCS-Report-2020_FINAL_December11.pdf

[12] International Energy Agency, *Towards zero emissions CCS in power plants using higher capture rates or biomass* (2019). https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/951-2019-02-towards-zero-emissions

Ensuring permanent storage of CO_2 is critical to the success of CCUS. Regulations outlining requirements for measurement, monitoring, and verification are needed to ensure long-term stability of carbon storage and prevent leakage of CO_2.

Life cycle carbon intensity of blue hydrogen

Figure 3 below illustrates the carbon intensity of blue hydrogen production compared to green and grey hydrogen including all emissions in the life cycle. Grey hydrogen is produced in the same way as blue, but without capturing the carbon. Green hydrogen is producing by splitting a water molecule using electrolysis powered by renewable electricity (see Appendix 2). The assumptions for each scenario are described in Appendix 1.

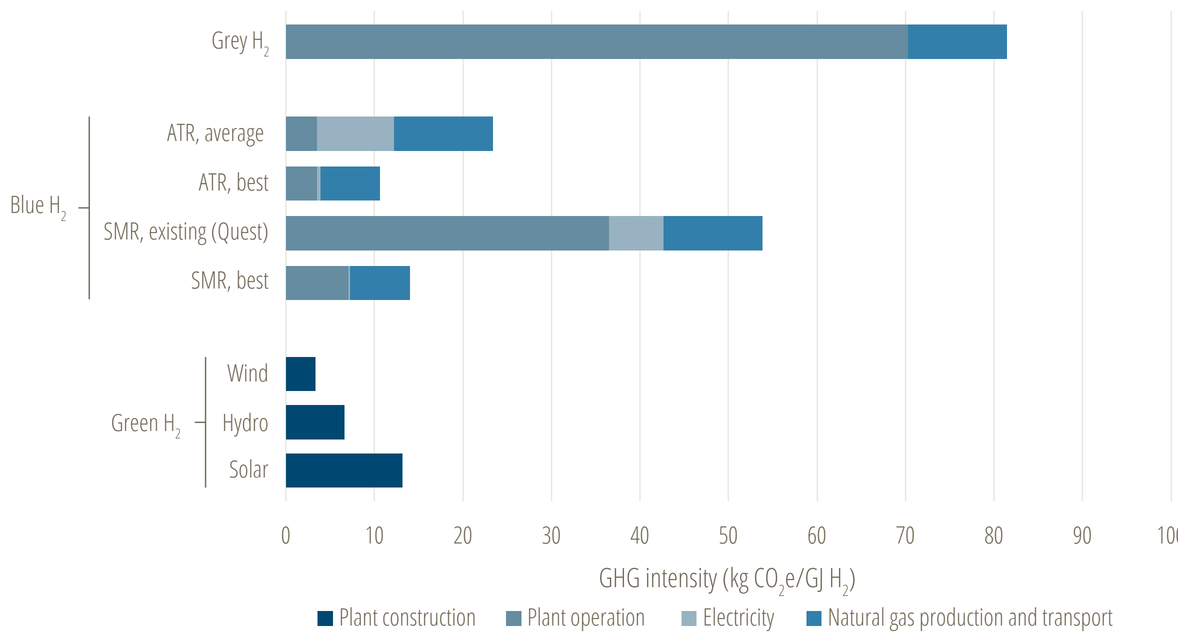

Figure 3. Life cycle carbon intensity of hydrogen production

This figure uses the 100-year global warming potential of methane of 34. The comparable life cycle carbon intensity of blue hydrogen that accounts for the strong short-term impact of methane (by using a 20-year global warming potential of 86) is shown in Appendix 1.

As Figure 3 demonstrates, there are a wide range of carbon intensities for blue hydrogen, depending on the choice of technology (SMR or ATR), carbon capture rate, emissions associated with imported electricity, and the emissions from natural gas production (which vary by production basin). Existing production at the Shell Quest facility has a higher carbon intensity primarily driven by a lower carbon capture rate. New SMR and ATR facilities can achieve much better performance if they capture over 90% of plant emissions, if emissions from natural gas production are reduced, and if the electricity for the process is produced from non-emitting sources. Emissions from construction of SMR and ATR plants with CCS are negligible over the volume of hydrogen produced.

Green hydrogen, produced via electrolysis and powered by renewable electricity, has a much lower carbon intensity than blue hydrogen, but there is variation depending on the source of electricity. All of the emissions associated with green hydrogen are from building the electricity plants (solar, wind, hydro, or other). Producing green hydrogen from solar electricity results in the highest emissions because most solar panels are currently manufactured in China, in factories mainly powered by coal.

Grey hydrogen is produced from natural gas (via SMR or ATR), but without carbon capture, so its emissions intensity is highest.

Appendix 2 shows the sources of emissions in the life cycle of green and grey hydrogen production.

Global state of blue hydrogen production

Blue hydrogen production is still a nascent industry. Globally there are four facilities in operation, and another three proposed. These projects are listed in Table 1.

Table 1. Existing and proposed blue hydrogen projects

Facility	Location	Production method	Started operation	Application	Estimated capture rate[13]
Quest	Alberta, Canada	SMR	2015	Bitumen upgrader	43%
Air Products Port Arthur	Texas, USA	SMR	2013	Oil refining	40%
Enid	Oklahoma, USA	SMR	1982	Fertilizer production	39%
Nutrien	Alberta, Canada	SMR	2020	Fertilizer production	29%
H2H Saltend[14]	United Kingdom	ATR	Proposed 2026	Humber industrial facilities	95% proposed

[13] Capture rates are estimated based on reported quantity of CO_2 captured at each facility and GHG emissions from the facility reported in national inventories.

[14] Equinor, "H2H Saltend." https://www.equinor.com/en/what-we-do/h2hsaltend.html

Air Products Alberta[15]	Alberta, Canada	ATR	Proposed 2024	Refining, petrochemicals, electricity and freight transport	95% proposed
H2Teesside[16]	United Kingdom	Unknown	Proposed 2027	Teesside industrial facilities	Unknown

Blue hydrogen in a net-zero economy

The pursuit of hydrogen and considerations of its climate benefit come at critical time in climate and energy policy globally. Many countries, including Canada, have committed to achieving net-zero emissions by 2050. There is also an expectation for countries to increase climate ambition and increase carbon reduction goals for 2030. The International Energy Agency's (IEA) recently released net-zero pathway report offers some insight when policy makers consider the role hydrogen could play in Canada. [17]

In order to be consistent with carbon neutral by 2050, new hydrogen production will need to have a carbon capture rate over 95% and low upstream emissions. Ultimately, hydrogen production will need to have net-zero life cycle emissions by reducing facility and upstream emissions as much as possible and offsetting the remainder.

Energy conservation and renewable energy play a large role in meeting our future energy demands; the IEA's scenario shows low carbon and renewable hydrogen could play a large role in the future with hydrogen demand rising more than six-fold in 2050.[18] In this scenario, more than 60% of hydrogen production is green (i.e. using water electrolysis).[19]

The IEA suggests, however, that broad use of hydrogen across sectors will require significant investment and planning, and points to the difficulty and costs of transporting hydrogen long-distances: "Developing the infrastructure for hydrogen at the pace required in [the net-zero scenario] would involve considerable investment risks along the value chain of production,

[15] Air Product, "Air Products Announces Multi-Billion Dollar Net-Zero Hydrogen Energy Complex in Edmonton, Alberta, Canada," news release, June 9, 2021. https://www.airproducts.com/news-center/2021/06/0609-air-products-net-zero-hydrogen-energy-complex-in-edmonton-alberta-canada

[16] BP, "BP plans UK's largest hydrogen project," news release, March 18, 2021. https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-plans-uks-largest-hydrogen-project.html

[17] International Energy Agency, *Net Zero by 2050: A Roadmap for the Global Energy Sector* (2021) https://www.iea.org/reports/net-zero-by-2050

[18] *Net Zero by 2050,* 129.

[19] *Net Zero by 2050,* 76.

transport and demand ranging from hydrogen production technologies through to low-emissions electricity generation and CO_2 transport and storage." CCUS is designed to be applied to large SMR plants that produce high volumes of hydrogen (100 tonnes per day or greater) because large plants provide a sufficient concentration of CO_2 to keep the rate of capture in the order of millions of tonnes of CO_2 per year to be economical.[20] For CCUS to be cost effective, a consistent large-scale demand for hydrogen is needed.[21]

A large share of emissions reductions from fossil fuels outlined in the IEA's net-zero pathway is due to the elimination of all technically avoidable methane emissions by 2030. Methane emissions — which have significantly higher global warming impact than CO_2 does — amounted to 98 megatonnes in 2019, or 13% of Canada's total greenhouse gas emissions. These came mostly in the form of vented and leaked gas from oil and natural gas systems, with further emissions from agriculture and landfills. As discussed above, methane is a source of emissions in the life cycle of blue hydrogen; the long term viability of blue hydrogen as a low-carbon energy carrier depends on addressing these upstream emissions.

Conclusion

Any investment in blue hydrogen will have to consider the full life cycle impacts of hydrogen production and distribution. If blue hydrogen is to be able to compete as a contributing pathway to a net-zero future, significant emissions must be addressed, including emissions from plant operation and upstream natural gas extraction. Upstream emissions from natural gas extraction will have to be virtually eliminated and a rate of carbon capture above 95% will need to be employed.

Currently, production of hydrogen as an energy carrier is still in its early stages. Most blue hydrogen facilities in operation today are integrated into refineries and fertilizer plants and were built before carbon pricing and meaningful climate targets called for high rates of capture. New facilities built to produce hydrogen as a mass market fuel will need to adopt the best available technology and achieve carbon capture rates over 95% to provide return on investment with a net climate benefit by significantly lowering the carbon intensity for blue hydrogen.

By 2050 all fuels used, including hydrogen, will need to be close to carbon neutral. Governments and proponents will need to provide rigorous, consistent information on life cycle emissions intensity of proposals.

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[20] International Energy Agency, *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS* (2017). https://ieaghg.org/exco_docs/2017-02.pdf

[21] One tonne of hydrogen can fuel 2000 light duty vehicles per day, assuming a hydrogen consumption rate of 0.5 kg/vehicle/day.

Appendix 1. Life cycle GHG intensity analysis of hydrogen production

Table 2 shows the assumptions used to calculate the carbon intensity of grey, blue and green hydrogen production under various scenarios. The contribution of each step in the life cycle of hydrogen production to the total GHG intensity is also shown for each scenario. The upstream natural gas emissions intensity was calculated based on 2018 emissions levels from Canada's national inventory and gross natural gas production assuming a 40% reduction in methane emissions from 2012 levels.[22, 23] A 100-year global warming potential (GWP) of 34 was used to convert methane emissions to CO_2e. (Figure 4 shows the life cycle carbon intensity of hydrogen based on a 20-year methane GWP of 86 instead.)

The baseline gas leak rate was calculated to be 1.0% in Alberta and 0.26% in British Columbia, excluding oilsands methane emissions, based on 2018 data.[24] In the analysis presented here, leak rates in Alberta and B.C. of 0.6% and 0.16%. were used, accounting for a 40% reduction in methane emissions from 2012 levels which is in line with the current federal target. Leak rates are calculated based on the amount of gas that vented and leaked from the natural gas supply chain divided by total gross natural gas production.

[22] Government of Canada, 2021 National Inventory Report (NIR) (2021). https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b

[23] Statistics Canada, "Supply and disposition of natural gas, monthly (data in thousands) (x 1,000)" Table 25-10-0055-01 (August 2021). https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2510005501&pickMembers%5B0%5D=1.1&pickMembers%5B1%5D=3.2&cubeTimeFrame.startMonth=01&cubeTimeFrame.startYear=2016&cubeTimeFrame.endMonth=05&cubeTimeFrame.endYear=2021&referencePeriods=20160101%2C20210504

[24] This is comparable to a leak rate of 1.4% based on the U.S. Environmental Protection Agency national inventory. Ramón A. Alvarez et al., "Assessment of methane emissions from the U.S. oil and gas supply chain," *Science* 361, no. 6398, (2018). https://science.sciencemag.org/content/361/6398/186

Studies in the U.S. and Canada have shown that methane emission are underestimated by 40% to 100%.[25, 26, 27, 28] Thus, methane emissions are very likely higher than currently inventory estimates. Methane has a strong short-term impact as shown by the high 20-year GWP. However, methane can also be addressed cost effectively using existing technology.[29]

[25] "Assessment of methane emissions from the U.S. oil and gas supply chain,"

[26] Elton Chan et al., "Eight-Year Estimates of Methane Emissions from Oil and Gas Operations in Western Canada Are Nearly Twice Those Reported in Inventories," *Environmental Science and Technology* 54, 23, (2020). https://pubs.acs.org/doi/10.1021/acs.est.0c04117

[27] Matthew R. Johnson et al., "Comparisons of Airborne Measurements and Inventory Estimates of Methane Emissions in the Alberta Upstream Oil and Gas Sector," *Environmental Science and Technology* 51, no. 21 (2017). https://pubs.acs.org/doi/10.1021/acs.est.7b03525

[28] Matthew R. Johnson and David R. Tyner, "A case study in competing methane regulations: Will Canada's and Alberta's contrasting regulations achieve equivalent reductions?" *Elementa: Science of the Anthropocene* 8, no. 7 (2020). https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.403/112749/A-case-study-in-competing-methane-regulations-Will

[29] Jan Gorski, *The case for raising ambition in curbing methane pollution* (Pembina Institute, 2021). https://www.pembina.org/pub/case-raising-ambition-curbing-methane-pollution

Table 2. Assumptions in calculated GHG intensity of hydrogen production for various scenarios

Scenario	Carbon capture rate	GHG intensity (kg CO_2e/GJ H_2)					Assumptions		
		Natural gas production and transport	Plant operation	Electricity	Plant construction	Total	Upstream gas production	Electricity import	Plant construction
Grey H_2	0%	11.1	70.3	0		81.5	Alberta gas GHG intensity = 8.4 kg CO_2e/GJ natural gas (0.6% leak rate)	N/A	negligible[30]
Blue H_2									
ATR, average performance	95%	11.1	3.5	8.7		23.4	Alberta gas GHG intensity = 8.4 kg CO_2e/GJ natural gas (0.6% leak rate)	Alberta electricity grid average GHG intensity from 2023 to 2042, based on CER 2020 evolving scenario	negligible
SMR, existing (Quest)	48%	11.1	36.6	6.1		53.8		Alberta electricity grid GHG intensity in 2019 from NIR 2021 report	negligible
ATR, high performance	95%	6.7	3.5	0.4		10.6	B.C. gas GHG intensity = 5.1 kg CO_2e/GJ natural gas (0.16% leak rate)	BC electricity grid average GHG intensity from 2023 to 2042, based on CER 2020 evolving scenario	negligible
SMR, high performance	90%	6.7	7.0	0.2		14.0			negligible

[30] Pamela L. Spath and Margaret K. Mann, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming* (National Renewable Energy Laboratory, 2001). https://www.nrel.gov/docs/fy01osti/27637.pdf

Scenario	Carbon capture rate	GHG intensity (kg CO_2e/GJ H_2)					Assumptions		
		Natural gas production and transport	Plant operation	Electricity	Plant construction	Total	Upstream gas production	Electricity import	Plant construction
Green H_2									
Wind	--	--	--	--	3.3	3.3		[31, 32]	
Hydro	--	--	--	--	6.6	6.6			
Solar	--	--	--	--	13.2	13.2			High emissions because most solar panels are currently manufactured in China, in factories mainly powered by coal.

The higher heating value of hydrogen and natural gas was used to convert the GHG intensity from a mass to energy basis.

[31] Electricity consumption for green hydrogen from: Zen and the Art of Clean Energy Solutions, *British Columbia Hydrogen Study* (2019). https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf

[32] Life cycle GHG emissions of electricity generation from: IPCC, “Annex III: Technology-specific cost and performance parameters.” In: *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report* (2014). https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf

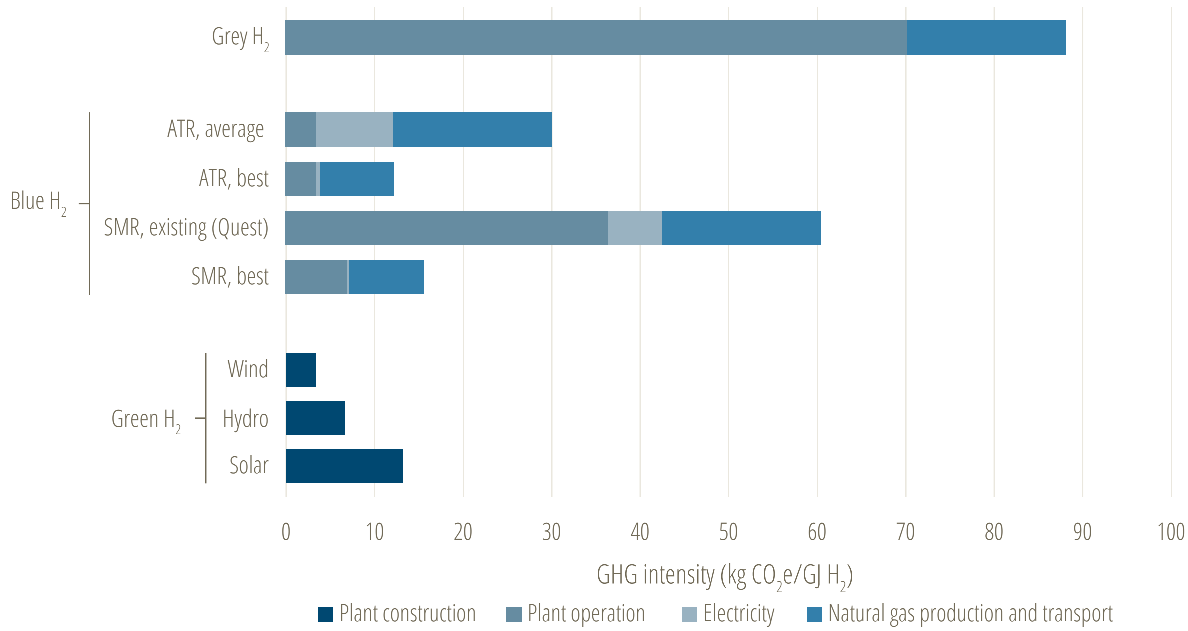

Figure 4. Life cycle carbon intensity of hydrogen using a methane GWP of 86

Appendix 2. Grey and green hydrogen production processes

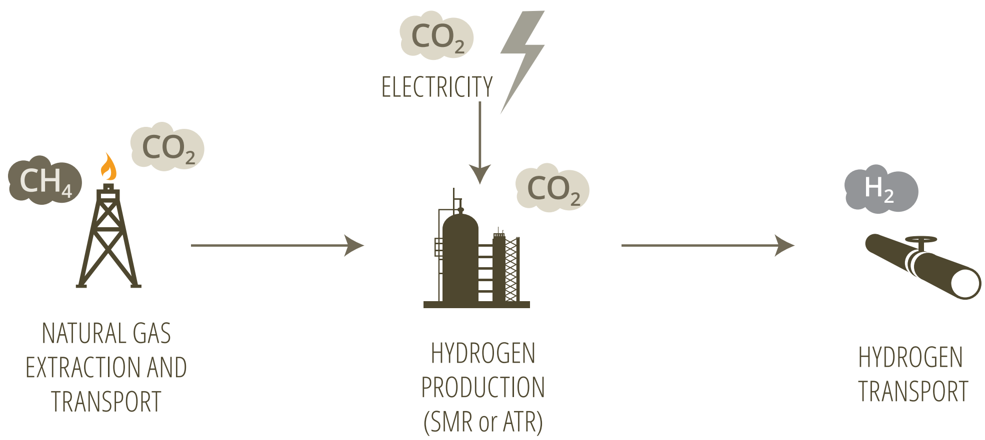

Figure 5. Grey hydrogen production process

In grey hydrogen production, carbon emissions are not captured.

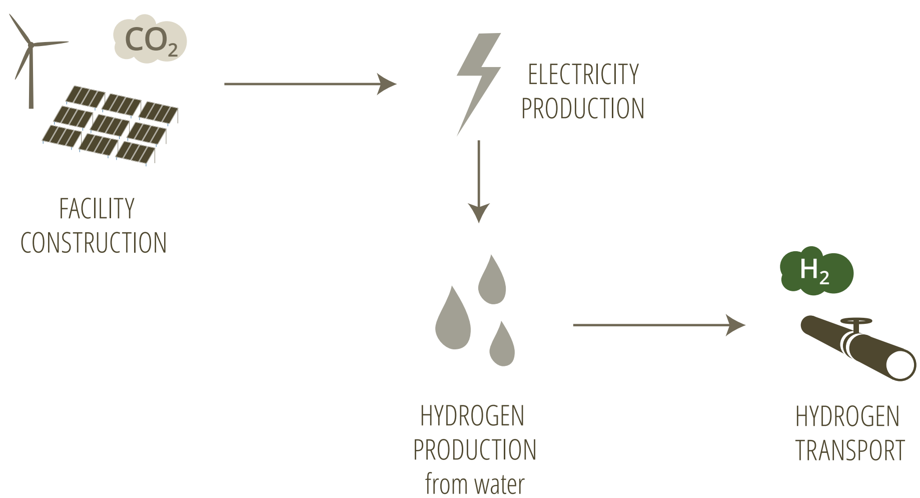

Figure 6. Green hydrogen production process

In green hydrogen production, carbon is emitted in the construction of the renewable electricity facilities (wind turbines, solar panels, hydro plants, etc.). The electricity produced is emission-free.