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STANDARDS RESEARCH

Carbon Capture and Geological Storage Technologies in Hydrogen Production

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Executive Summary

Hydrogen has been identified as a critical component of Canada's path toward reaching net-zero greenhouse gas emissions by 2050. While production technologies, such as electrolysis, are advancing, it is expected that reforming natural gas through conventional technologies will continue to play an important role in meeting Canada's future hydrogen demands. For these fossil fuel-based technologies to attain net-zero greenhouse gas emissions, producers will likely have to employ carbon capture technologies at their facilities and couple the carbon capture with transportation and long-term sequestration of carbon dioxide.

Currently, there are no standards specific to the deployment of carbon capture in the hydrogen production industry. While existing standards applicable to carbon capture in the power generation industry can provide a starting point, differences in these industries' processes and products leave gaps in standardization that may inhibit the adoption of carbon capture technologies in the hydrogen industry.

This report provides technical background on hydrocarbon-based hydrogen production technologies and applicable carbon capture technologies and gives examples of currently operating hydrogen projects employing these technologies. It then provides an overview of the standards landscape relevant to carbon capture technologies in hydrogen production and identifies gaps and areas where further standardization could support the deployment of carbon capture in hydrogen production. The following are key areas where standardization could be beneficial:

- System boundaries and key performance indicators for evaluating the performance of carbon capture technologies should be appropriately defined for application in hydrogen production.
- Guidance on technology qualification for carbon capture technologies may help in managing and reducing the risk inherent in scaling up carbon capture technologies and applying them in new configurations.
- Standards specific to carbon capture in hydrogen production should be consistent with standards on life cycle assessment, particularly those classifying hydrogen based on its carbon intensity.



"As hydrogen does not produce carbon dioxide emissions during end-use, it has been identified as a critical tool in attaining Canada's goal of reaching net-zero greenhouse gas emissions by 2050."

1 Introduction

Hydrogen (H_2) is a versatile energy carrier that can be directly combusted to produce heat, converted to electricity in fuel cells, and used as a feedstock in various industrial chemical production processes. As it does not produce carbon dioxide (CO_2) emissions during end-use, it has been identified as a critical tool in attaining Canada's goal of reaching net-zero greenhouse gas (GHG) emissions by 2050 [1]. For this to occur, Canada would need to support the development of pathways for large-scale production of low-carbon intensity (CI) hydrogen.

Global annual hydrogen production was 144 megatonnes in 2018. Most was produced from fossil fuels, with 48% derived from natural gas and another 18% from coal. On the end-use side, 60% of total demand is for pure hydrogen in applications such as oil refining and ammonia production, with the other 40% of demand for mixed hydrogen in applications such as methanol production and industrial heating [1].

In Canada, an estimated 3 megatonnes of hydrogen is produced annually, primarily via steam reforming of natural gas (i.e., steam-methane reforming (SMR)). Other mature production pathways in Canada include electrolysis of water; gasification and pyrolysis of coal, oil, and biomass; and reforming of landfill and agricultural gases [1]. Looking ahead to 2050, an eight-fold increase in national hydrogen production would be required to meet projections of hydrogen meeting 27% of Canada's primary energy demand [2]. As the country transitions to low-CI hydrogen, reforming of natural gas is likely to continue playing a significant role due to Canada's abundant supply of low-cost natural gas. As the conventional SMR process produces 9–10 tonnes of CO_2 per tonne of hydrogen [3], [4], achieving a low CI requires technical innovation to reduce or eliminate these CO_2 emissions.

The CI of hydrogen, irrespective of the production method, is a topic of interest for standards developers, hydrogen producers, and hydrogen users around the world. An estimated baseline of CO_2 emissions from SMR production of hydrogen without CO_2 capture in Canada, on a cradle-to-gate basis (i.e., emissions from resource extraction and production), is 89–97 gCO_2e/MJH_2 [5–7]. As future regulations, codes, and standards are put in place for limiting the CI of hydrogen production, producers should ensure that technology solutions being put in place can meet the requirements in their region and in their consumers' region(s).

In Canada, the Hydrogen Strategy for Canada recommends a target cradle-to-gate CI for hydrogen of 36.4 gCO_2e/MJH_2, based on the European Commission's CertifHy program recommendation, which is 60% below the intensity of hydrogen produced from natural gas without CO_2 capture [1]. Provincial strategies, including the B.C. Hydrogen Strategy and the Alberta Hydrogen Roadmap, echo this recommendation [6], [7]. To be considered a low-CI fuel, as per the Clean Fuel Regulations (SOR/2022-140), the CI of hydrogen must be below 67.8 gCO_2e/MJ H_2 over its life cycle from cradle to grave [8].

Carbon capture and storage (CCS) can be coupled with hydrocarbon-based hydrogen production processes to provide the required reduction in CO_2 emitted during production. While a variety of technology options exist at various maturity levels, CCS has been demonstrated at the commercial scale in Canada in projects including Boundary Dam, Shell Quest, and the Alberta Carbon Trunk Line [9]. These projects currently sequester about 4 megatonnes of CO_2 per year [1]. Hydrogen production exclusively via SMR coupled with CCS at the amounts meeting the 2050 net-zero GHG emissions demands would require capturing and storing about 203 megatonnes of CO_2 per year, which represents a 50-fold increase over current CO_2 sequestration levels [2]. Achieving this target will likely require a combination of incentives, investments, and policies to spur technology development and deployment.

This research report reviews the existing landscape of codes and standards applicable to carbon capture and geological storage in hydrogen production. It identifies needs and gaps via a literature review and consultation with key experts and stakeholders in the field. Finally, it provides recommendations for standardization of CCS in hydrogen production to support the growth of Canada's hydrogen economy and attainment of net-zero emissions by 2050.

2 Methods

Information on codes and standards applicable to CCS in hydrogen production was collected via a literature review and a workshop held with stakeholders and experts in the field.

The literature review covered three primary areas: existing commercial hydrogen production pathways from carbon-based feedstocks; existing commercial and emerging CCS technologies applicable to hydrogen production; and national and international codes and standards relevant to CCS in hydrogen production. Information was collected from academic publications; industry, governmental, and non-governmental organization white papers and reports; company websites; and standards development organization websites.

The workshop gathered input on the topic of CCS in hydrogen production by posing the following discussion questions to the participants:

- Across the entire value chain of hydrogen production, are there ways to reduce or eliminate GHG emissions?
- What technologies are currently being used for carbon capture and how effective are they?
- Do we need standards for the design of these technologies?
- Are there tests to measure the performance? Do we need standards for testing the performance?
- Should a specific capture rate be attached to blue hydrogen? Are there regulations on capture rate?
- Are there any regulations on CCS in hydrogen productions?
- Are there any other issues around carbon capture in blue hydrogen production that standards can help with?
- Right now, the main challenge to CCS deployment is cost. What actions would incentivize the use of CCS technologies? Will transparent and predictable regulation of access to pore space for the geological storage of CO_2 help?

3 Results and Discussion

3.1 Production of Hydrogen from Carbonaceous Feedstocks

3.1.1 Steam-Methane Reforming

Steam reforming of methane, the main constituent of natural gas (NG), is the most technically mature and widely used hydrogen production technology globally [10]. A simplified flow diagram of a conventional SMR process is presented in Figure 1. Steam and natural gas are supplied as reactants to the reformer tubes, which are loaded with a nickel catalyst and heated externally to between 700 and 950 °C by air-fired combustion of more natural gas (or similar gaseous fuel) to drive the endothermic reforming reaction given by Equation (1).

$$CH_4 + H_2O \rightarrow 3H_2 + CO \qquad \Delta H^0 = 206\ kJ/mol$$

(Eq 1)

This produces synthesis gas (syngas), a mixture comprising mainly H_2 and carbon monoxide (CO), along with CO_2, unreacted CH4, and excess steam. The syngas goes through high-temperature (between 310 and 450 °C) and low-temperature (between 200 and 250 °C) shift reactors, in which the steam converts CO to CO_2, as per Equation (2), increasing the yield of H_2 in the process [11].

$$CO + H_2O \rightarrow H_2 + CO_2 \qquad \Delta H^0 = -41\ kJ/mol$$

(Eq 2)

As the shift reactors operate at much lower temperatures than the reformer, sensible heat must be removed from the syngas stream before it enters the first shift reaction. This heat is commonly used to produce the steam for the reforming reaction as well as power via a steam turbine, helping to offset the facility power requirements, as shown by the water-steam loop in Figure 1. To prevent accumulation of impurities within the steam system, a blowdown is used to periodically vent water, meaning that additional makeup water is required, as shown.

The process gas exiting the shift reactor, now comprising mainly H_2 and CO_2, goes through cooling, CO_2 removal, and hydrogen purification processes, which produces a high-purity H_2 stream.

The tail gas (i.e., the gas remaining after hydrogen purification), which contains CO_2, CO, CH_4, and some H_2, is recycled to the reformer to supplement the heating fuel requirement and reduce the overall natural gas consumption. Some of the tail gas may also be vented.

While natural gas is the most commonly used feedstock in the SMR process, steam reforming can also be applied to other feedstocks, including landfill gas or syngas produced from gasification. Depending on the presence of other species in the feedstock, additional pre-treatment steps may be required upstream of the reformer, including desulphurization to remove sulphur species or pre-reforming to convert higher hydrocarbons to methane and prevent catalyst poisoning [12].

Figure 1: Simplified process flow diagram of SMR

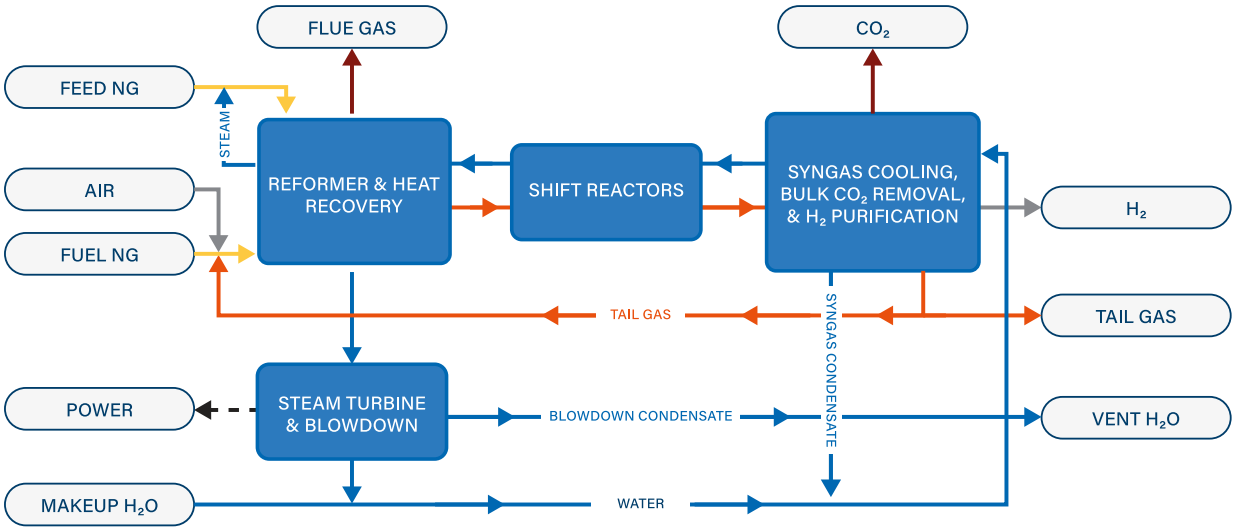
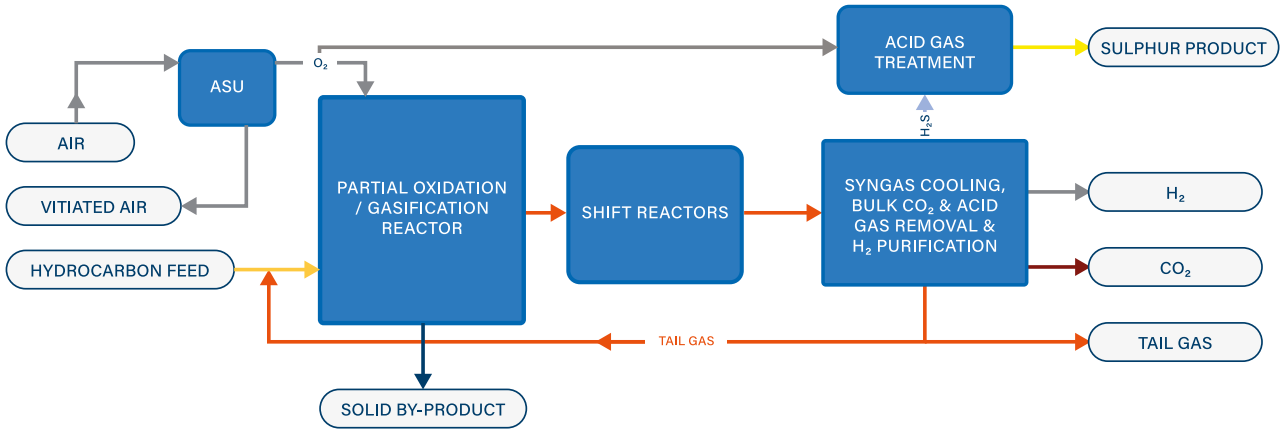


Figure 2: Simplified process flow diagram of gasification / POx with raw gas shift



The major sources of CO_2 emissions from the SMR process are the reformer flue gas and the CO_2 removed from syngas during hydrogen purification, typically emitting approximately 4.5 and 5.5 tonnes of CO_2 per tonne of H_2 produced, respectively, when natural gas is the feedstock [4]. Some CO_2 may also be emitted in the tail gas, depending on the specific process configuration and conditions.

3.1.2 Partial Oxidation / Gasification

Gasification refers to a suite of partial oxidation (POx) processes in which carbon-based fuels are converted into a syngas product with a usable heating value [13], [14]. While gaseous fuels, such as natural gas, refinery waste gas, or Fischer-Tropsch off-gas, can be used as the feedstock for gasification processes, this would typically be done to attain a high-CO syngas [13]. Therefore, for the purposes of this report, this section will focus on high-H_2 syngas production via gasification of solid and liquid feedstocks, such as coal, petroleum by-products, and biomass.

A simplified process flow diagram of a gasification process employing a raw water-gas shift reaction is shown in Figure 2. In the POx reactor, the hydrocarbon feed is reacted with a sub-stoichiometric quantity of oxygen to produce a syngas containing primarily H_2 and CO. Although several chemical reactions take place in the POx reactor, the dominant H_2 production mechanism is the exothermic POx reaction given in Equation (3).

$$CH_4 + \frac{1}{2}O_2 \rightarrow 2H_2 + CO \qquad \Delta H0 = -36\ kJ/mol$$

(Eq 3)

Pure oxygen (O_2) produced in an air separation unit (ASU) is typically used as the oxidant, and oxygen-depleted (vitiated) air from the ASU is released back to the atmosphere. Depending upon the nature of the hydrocarbon feed, the raw syngas produced in the POx reactor often contains acid gases, such as hydrogen sulphide (H_2S) and carbonyl sulphide (COS), which must be removed. In the process shown in Figure 2, referred to as a raw gas shift process, the COS will largely be converted to H_2S in the shift reactor, and H_2S is removed in the subsequent bulk gas cleaning step, which also includes CO_2 removal. However, depending on a variety of site-specific conditions, a clean gas shift process may be employed, in which sulphur species are removed upstream of the shift reactors followed by CO_2 removal downstream of the shift reactors.

The conditions in the reactor, the solid by-product produced through the POx, and the required steps for syngas treatment will all depend upon the hydrocarbon feed being processed, as will the quantity of CO_2 produced per unit of H_2 [13].

3.1.3 Autothermal Reforming

Autothermal reforming (ATR) is effectively a combination of steam reforming and POx, in which the endothermic reforming reaction given by Equation (1) is driven by heat from the exothermic POx reaction given by Equation (3). The two reactions are balanced such that the reformer's temperature remains constant (i.e., autothermal). A simplified flow diagram of the ATR process is presented in Figure 3. Air may be used as the oxidant instead of pure O_2 at smaller scales, which would lead to a significant quantity of nitrogen (N_2) in the syngas [10].

As with SMR, the reforming reaction in ATR is completed over a nickel catalyst at a temperature between 700 and 950 °C, which may necessitate additional pre-treatment of the feedstock upstream of the reformer. Natural gas is typically the feedstock to the ATR process, although higher hydrocarbons can also be used as the feedstock if a suitable catalyst is used [15].

Unlike an SMR reactor, an ATR reactor does not contain reformer tubes to separate the combustion and reforming processes. Rather, both the combustion and reforming occur within the same chamber, meaning that all CO_2 produced in the reformer is contained in the syngas stream exiting the reformer and the major source of CO_2 within the process is the bulk CO_2 removal after the shift reactors. The ATR process produces slightly less CO_2 per unit of H_2 compared with SMR at about 8.4 tonnes of CO_2 per tonne of H_2 when natural gas is the feedstock [3].

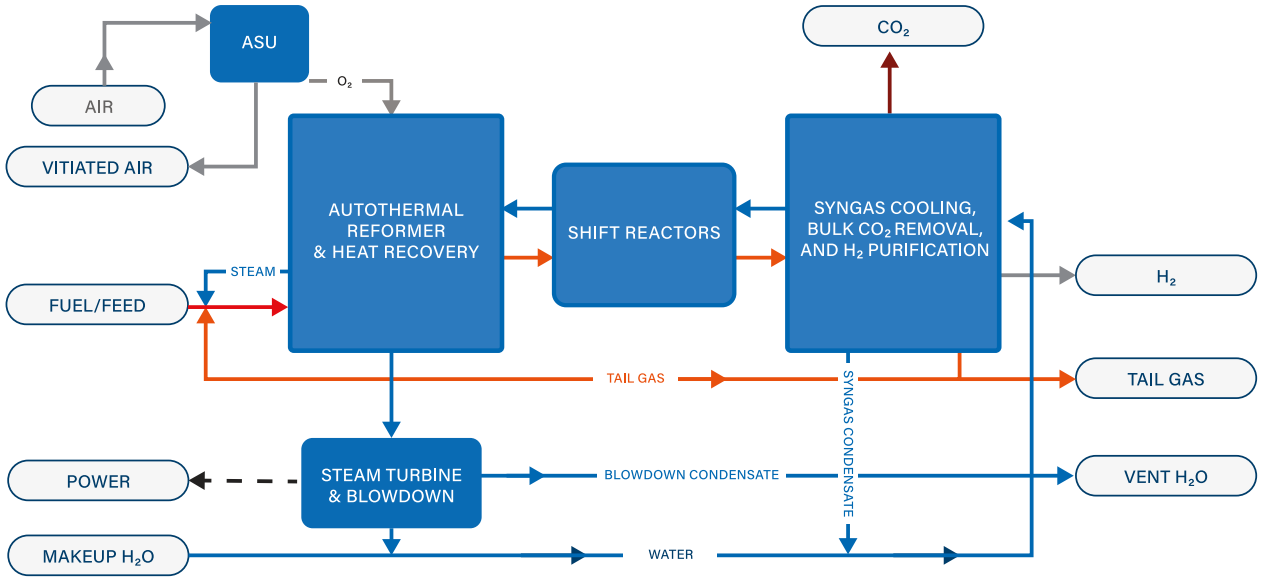
3.1.4 Natural Gas Decomposition

Natural gas decomposition, also referred to as natural gas pyrolysis, is a process in which natural gas is decomposed to H_2 and solid carbon under an oxygen-free environment and at high temperatures. These processes were first used in the 1930s in the thermal black process to produce carbon black, with H_2 and other gaseous species produced considered to be by-products that were typically used as fuel to drive the process [16].The lack of oxygen means that CO_2 is not produced directly in the process [10]. The endothermic decomposition reaction is given by Equation (4):

$$CH_4 \rightarrow 2H_2 + C \qquad \Delta H0 = 75\ kJ/mol$$

(Eq 4)

Figure 3: Simplified process flow diagram of ATR



A general natural gas decomposition process is shown in Figure 4.

Natural gas is supplied to the decomposition reactor, along with a recycle gas stream from the H_2 purification step containing both H_2 and unreacted natural gas. As the decomposition reaction is endothermic, it requires heat input to proceed. There are three broad categories of natural gas decomposition processes: thermal decomposition, which occurs at temperatures over 1000 °C; catalytic decomposition, which typically employs a nickel catalyst and occurs at temperatures over 800 °C; and plasma decomposition, which occurs at temperatures up to 2000 °C. Thermal and catalytic processes using various reactor configurations are still under development at laboratory scale. Plasma decomposition processes are more advanced, and some have attained production scale in the thermal black process. However, newer technologies for producing carbon black have largely replaced the thermal black process, and the more recent development of natural gas decomposition processes focuses on H_2 as a main product or as a key co-product with carbon black. Currently, the only commercial-scale natural gas decomposition facility is Monolith's Olive Creek facility that employs a plasma process in Nebraska, USA [17]. Some plasma processes employ recirculation of a portion of the purified H_2 to the plasma torch, which reduces the overall H_2 yield [16].

Products of the decomposition reaction undergo a gas/solid separation step in which the gaseous product containing H_2 along with unreacted natural gas is separated from the catalyst and the solid carbon product. The gas is then cooled and the H_2 product is purified.

3.2 Carbon Capture Technologies Applicable to Hydrogen Production

3.2.1 Solvent-Based Absorption

3.2.1.1 Chemical Solvents

Chemical solvents were originally used to remove acid gases, including CO_2, from other gases in the natural gas industry in the 1930s. Several categories of chemical solvents are available, including amines, non-aqueous solvents, carbonate-based solvents, and phase change solvents [18].

Amines are the most widely used chemical solvents in acid gas separation processes [18]. A simplified flow diagram of a CO_2 scrubbing process using amines is presented in Figure 5. In the absorption column, a CO_2-containing gas stream is contacted with an aqueous amine solution. The amine reacts chemically with the CO_2 to form ammonium salts, and the CO_2-depleted gas exits at the top of the column. The CO_2-rich solvent is then pre-heated in the heat exchange network and circulated to the solvent regeneration

Figure 4: Simplified process flow diagram of generalized natural gas decomposition process

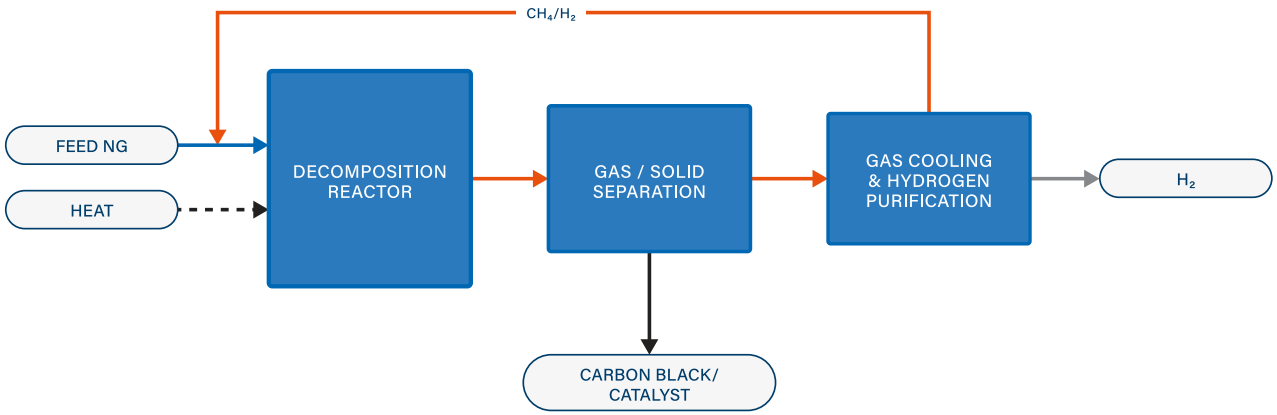
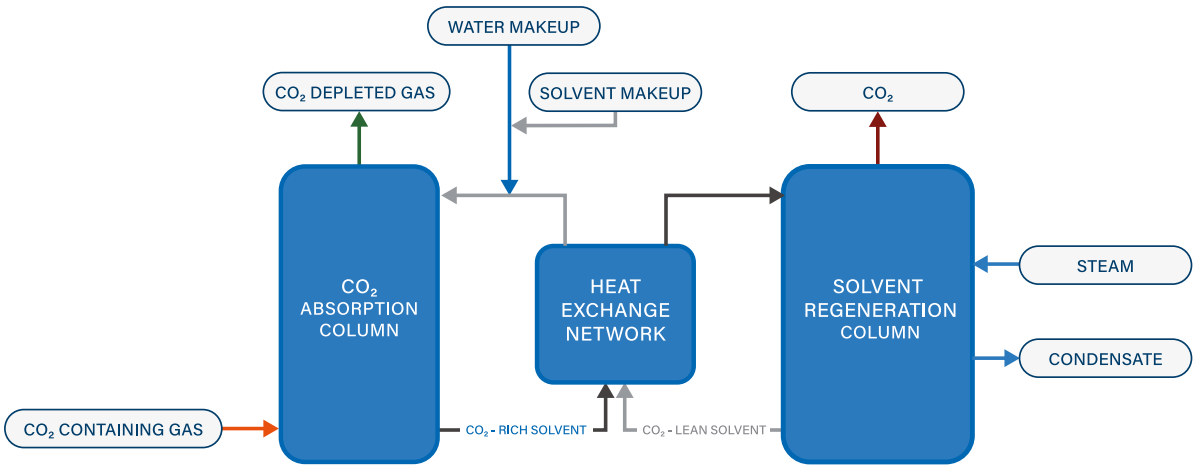


Figure 5: Simplified process flow diagram of chemical solvent CO_2 capture



column where it is further heated with steam to release the CO_2 and regenerate the amine. The regenerated solvent is cooled in the heat exchange network before being recirculated to the absorption column [18]. The CO_2 produced in the regeneration column will typically have a purity of at least 95%, with the balance primarily water along with other gas species that depend on the inlet composition of the gas being treated. This stream will need to be dried and compressed, typically reaching a purity from 98 to 99%, before being suitable for transportation and storage.

Many different amine solvents are used commercially, with monoethanolamine (MEA) popular due to its high reactivity, low toxicity, and biodegradability. Other commonly used amines include methyl diethanolamine (MDEA), aminomethyl propanol (AMP), and piperazine (PZ), which are comparatively more harmful and not easily biodegradable. Several companies employ proprietary blends of these solvents selected for characteristics that make them favourable to CO_2 scrubbing, including fast reaction kinetics and large CO_2 carrying capacity, which influence both capital and operating expenses. Amine processes can attain CO_2 capture rates of 95% or higher, although higher rates may be cost-prohibitive [18]. A Canadian example of amine capture technology deployed in hydrogen production is the Shell Quest project, in which CO_2 is captured from the process gas streams of three of the Scotford refinery's hydrogen manufacturing units. Since operations began in 2015, this project has captured and geologically sequestered over 7.7 Mt of CO_2, with a capture rate of 77.3% of the process emissions in 2022 [19].

While amine solvents are typically blended in 50–70 wt% water to reduce viscosity and corrosivity, the water content decreases the solvent working capacity while increasing the circulation rates and thermal regeneration energy, which negatively impacts performance and increases costs. For this reason, several technology developers are working on non-aqueous solvents, such as hydrophobic amines, organic liquids, and functionalized ionic liquids [18]. These solvents would be used in processes similar to what is shown in Figure 5, but without the requirement for makeup water [18].

Carbonate-based solvents have also been used in CO_2 scrubbing processes, with the advantage of a lower heat of desorption relative to amines, potentially leading to a lower thermal regeneration energy. An example of this type of solvent is aqueous ammonium carbonate, which has a higher CO_2 carrying capacity

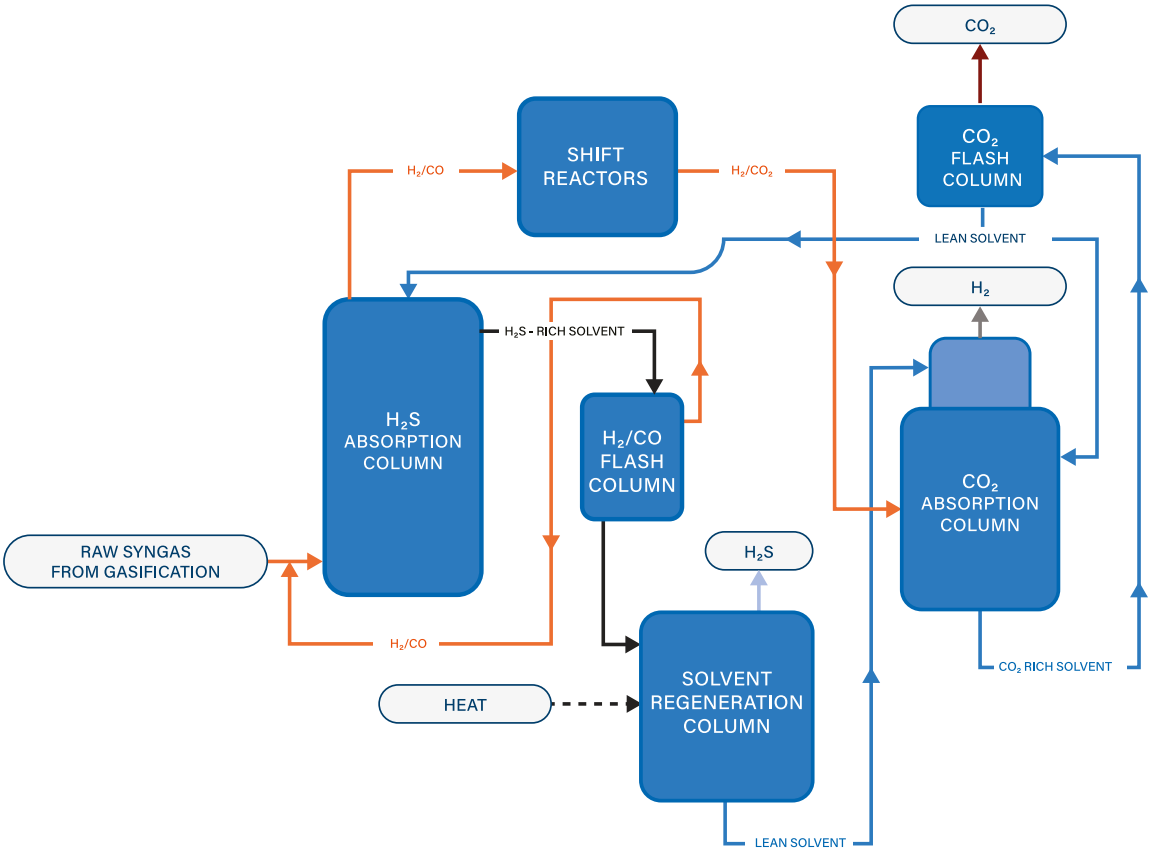
and lower solvent degradation rate relative to amines. This reaction can be accelerated with the addition of an enzyme catalyst, such as carbonic anhydrase, to the solvent. However, the loss of solvent to the flue gas is a significant drawback of this process, due to the high volatility of ammonia [18].

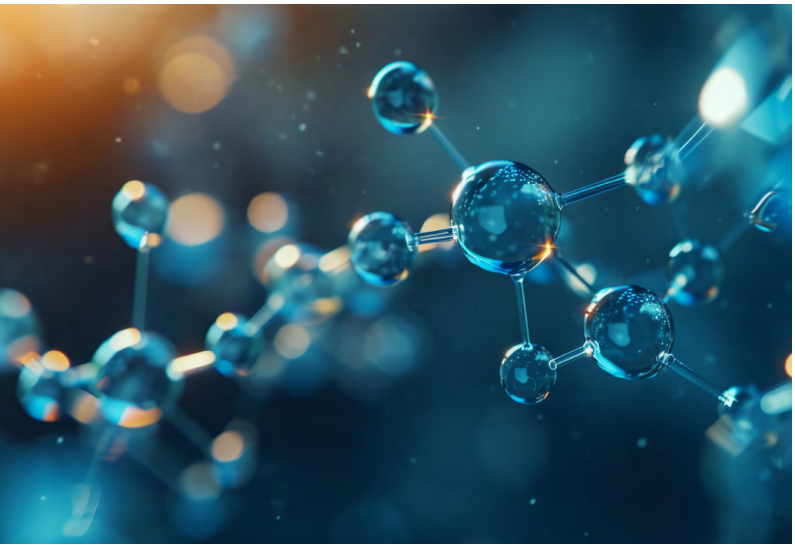
3.2.1.2 Physical Solvents

Physical solvents absorb acid gases based on solubility, without a chemical reaction. This means that, broadly speaking, they are most effective at absorbing CO_2 when the concentration of CO_2 in the gas being treated is high and will have a lower regeneration energy requirement in comparison with chemical solvents [20]. They are commonly used in gasification processes to remove H_2S, COS, and CO_2 from the syngas. Commercial physical solvents include refrigerated methanol, which selectively removes H_2S and COS over CO_2, and dimethyl ethers of polyethylene glycol (DMPEG), which does not require refrigeration but does not effectively remove COS. DMPEG is often used in raw gas shift processes, such as the one shown in Figure 2, while refrigerated methanol would more commonly be used in a clean gas shift process, such as the one shown in Figure 6.

The clean gas shift process consists of two absorption and two flash columns as well as a solvent regeneration column. The raw syngas produced from gasification enters the H_2S absorption column, where H_2S is absorbed into the solvent along with a small fraction of the H_2 and CO. The clean syngas exiting the H_2S absorption column is directed to the shift reactors, where the CO is converted to CO_2. The H_2S-rich solvent exiting the H_2S absorption column is passed through the H_2/CO flash column, where H_2 and CO are recovered and recycled back to the raw gas inlet. The H_2S-rich solvent is directed to a regeneration column, where it is

Figure 6: Simplified process flow diagram of a CO_2 removal process using a physical solvent and a clean gas shift





"In addition to the mature physical solvent technologies used in gasification processes, Air Liquide has developed a cold methanol process called Recticap(TM) that is tailored for capturing CO_2 from natural gas reforming processes."

heated to release the sulphur species and regenerate the lean solvent. The H_2/CO_2 gas mixture exiting the shift reactors enters the CO_2 absorption column, in which H_2 is finally separated from CO_2 via absorption of the CO_2 into the solvent. The bulk of the CO_2 is absorbed at the bottom of the CO_2 absorption column into the cold solvent supplied from the CO_2 flash column, while the remaining small fraction of CO_2 is absorbed at top of the column into the hot solvent supplied from the regeneration column. The CO_2-rich solvent then enters the CO_2 flash column, where the CO_2 is released and the solvent is regenerated. A part of the solvent is returned to the H_2S absorption column and a part to the bottom of the CO_2 absorption column [13]. The CO_2 stream can then be dried and compressed to be suitable for transportation and storage.

In addition to the mature physical solvent technologies used in gasification processes, Air Liquide has developed a cold methanol process called Recticap™ that is tailored for capturing CO_2 from natural gas reforming processes. As opposed to the process shown in Figure 6, Recticap™ removes only CO_2 from the raw syngas stream, as there are typically less impurities in reforming syngas. This allows for a CO_2 capture rate over 95% at a lower capital cost relative to conventional cold methanol processes [21].

3.2.2 Solid Sorbent-Based Adsorption

Adsorption processes using solid sorbents operate by selectively adsorbing one or more species from a fluid stream onto the surface of the adsorbing solid [22]. This can occur through two mechanisms, namely, physical adsorption or chemical adsorption. In physical adsorption, the adsorbed species are attracted to the sorbent through Van der Waals forces, which are relatively weak and therefore have a low heat of adsorption/desorption. In chemical adsorption, on the other hand, the adsorbed species forms a stronger covalent bond with the sorbent with a heat of adsorption/desorption comparable to the heat of reaction [18]. Adsorption processes can be classified as either temperature swing adsorption (TSA) or PSA by the type of energy input used to regenerate the adsorbent [23].

3.2.2.1 Temperature Swing Adsorption

TSA processes typically employ sorbents that adsorb the desired gas species at low temperatures and release them at high temperatures. The ideal temperature range will depend on the process that the TSA system is being integrated with and the availability of waste process heat. Typically, chemical sorbents will be more suited to TSA processes, as the adsorption capacity of physical sorbents is reduced at higher temperatures, requiring fast cycling to compensate for this characteristic [23].

Researchers and companies developing TSA technologies for CO_2 capture are working to build processes that reduce the cycle time required to adsorb and desorb CO_2 [24]. A Canadian example of this is the VeloxoTherm™ process developed by Svante Inc., which uses structured adsorbent beds in a rotating adsorption machine [24]. This reactor configuration is capable of attaining cycle times of under one minute, in contrast with the hours-long cycle times required for

many other TSA configurations, such as fixed beds or circulating fluidized beds [23], [24]. Figure 7 provides an example of the steps that would be involved in a process like this.

It should be noted that this figure is not a flowsheet of an actual TSA process, but rather a representation of the steps involved in an example TSA process. In the first step, the CO_2-containing gas is contacted with the sorbent at low temperature. CO_2 is adsorbed onto the sorbent, and the non-adsorbed gas exits the vessel. The CO_2-loaded sorbent is then heated with steam in the second step, which releases the CO_2. The steam/CO_2 stream exiting this step is cooled to remove the water, producing a high-purity CO_2 stream. In the third step, the heated and humidified sorbent is cooled and dried with air or pure N2. The dry regenerated sorbent then returns to the first step of the cycle. The CO_2 stream would need to be dried and compressed before being suitable for transportation and storage.

3.2.2.2 Pressure Swing and Vacuum Swing Adsorption

PSA processes employ sorbents that adsorb the desired gas species under elevated pressure and release them under reduced pressure. Vacuum swing absorption (VSA) is a specific case of PSA, in which the adsorbed gas species is released under vacuum and may be more economical when treating a low-pressure gas stream [23]. PSA cycles are rapid in comparison with TSA cycles in similar process configurations, with cycle times of minutes or even seconds attainable in fixed beds. Physical sorbents are typically more suited to PSA processes, with the selectivity for CO_2 an important characteristic.

PSA is already commonly used to purify H_2 produced in SMR processes. Historically, the intent has been to produce a high-purity H_2 product, with the purity of CO_2 produced of less concern. With the recent focus on CO_2 capture, more advanced process configurations are being studied to produce both high-purity H_2 and high-purity CO_2 via PSA [25], [26]. These configurations are often highly complex, with multiple fixed sorbent beds simultaneously undergoing multiple steps, including feed, rinse, depressurization, blowdown, purge, and re-pressurization, and multiple stages used to produce both H_2 and CO_2 at sufficiently high purity [26]. Since 2013, Air Products and Chemicals Inc. has been operating a VSA-based CO_2 capture process on two SMR units at the Valero Port Arthur Refinery in Texas, USA, with a design capture rate of 55% of the process CO_2 emissions [27], [28]. This capture process produces CO_2 with a purity over 98 mol% after compression, cooling, and drying with triethylene glycol [29].

Figure 7: Steps involved in a TSA process

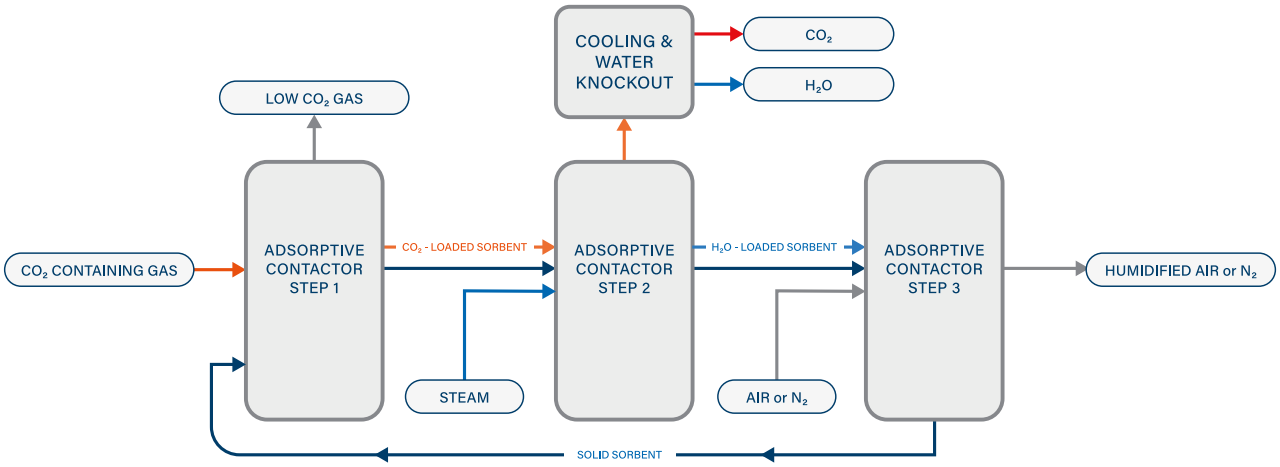
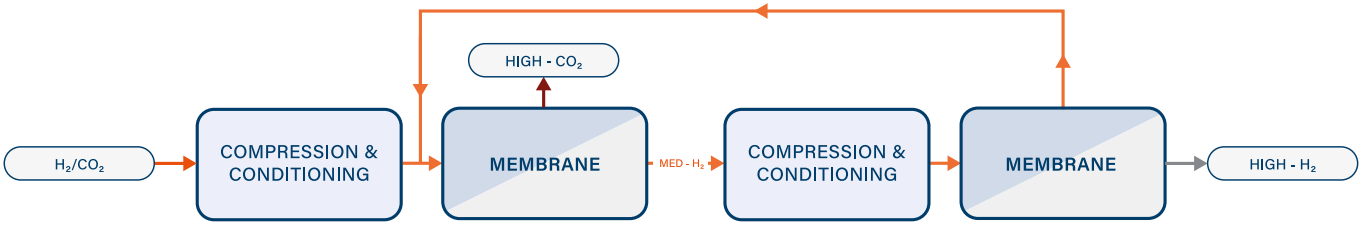


Figure 8: Simplified process flow diagram of a two-stage membrane process for separation of H_2 and CO_2



3.2.3 Membrane Separation

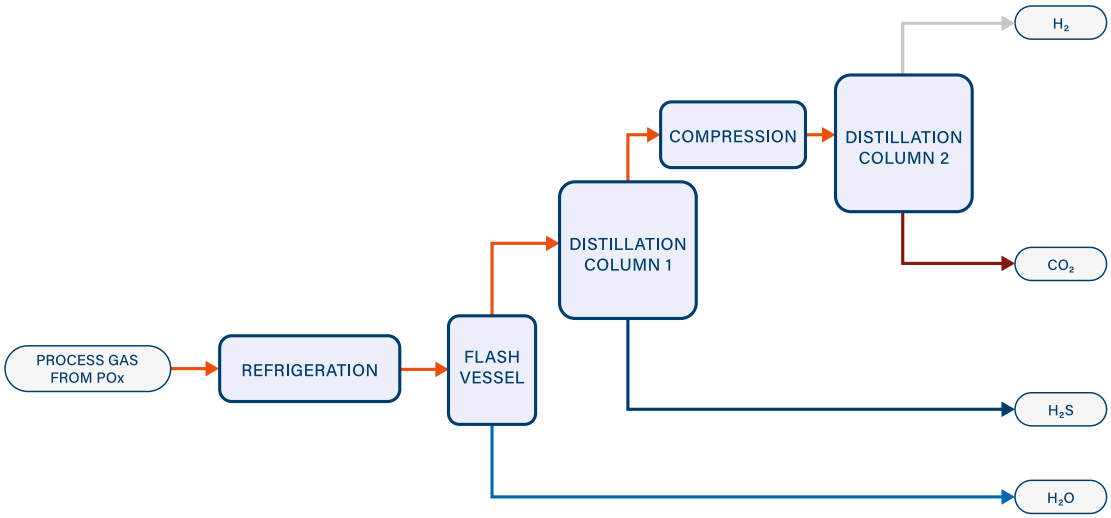
A membrane is a barrier that selectively restricts the transport of certain components in a fluid stream in order to produce a separation of those components. For this separation to occur, two things are required: a difference in permeability between the different solution components, referred to as the selectivity, and a driving force across the membrane. Components with a higher permeability will preferentially pass through the membrane into the permeate stream, while components with a lower permeability will preferentially remain in the retentate stream. The driving force is provided by the difference in the chemical potential of the solution across the membrane which, in most gas separation applications, is quantified by the difference in partial pressure [20].

A significant challenge in membrane separation processes is the inverse relationship between permeability and selectivity; that is, the more selective a membrane material is for a given gas species, the lower the permeability will be, and vice versa [30]. This limitation can be overcome to some extent by using multi-stage membrane processes, such as the one shown in Figure 8. In this process, the incoming H_2/CO_2 stream is compressed and conditioned before entering the membrane unit. The CO_2 preferentially remains in the retentate stream, while the H_2 permeates the membrane. The permeate stream from this membrane stage may require further compression and conditioning before entering the second membrane stage, where again the H_2 permeates the membrane and produces a relatively high-purity H_2 stream. The retentate stream from the second membrane stage is recycled back to the feed to the first stage to increase the overall H_2 recovery in the process.

The compression duty needed to attain the difference in partial pressure required for transport across the membrane can be significant and costly. Two approaches can be used to generate the required difference in partial pressure: compression of the feed stream or vacuum on the permeate stream. The first approach can produce a much higher driving force; however, as the gas volume is significantly larger in the feed stream in comparison with the permeate stream, the energy duty is much higher [20]. The second approach allows for a reduced energy duty, but the lower driving force necessitates much larger membrane areas to attain the necessary H_2 recovery [20].

The selectivity of conventional membrane materials for H_2 over CO_2 tends to be somewhat low, as these species have similar physical characteristics that influence selectivity, such as kinetic diameter. Developing membranes with higher selectivities for H_2 is an area of active research [30]. Even with multi-stage processes being employed, the overall recovery and purity attainable with membranes tend to be lower than other H_2/CO_2 separation processes. Because of this, application development leans toward processes where membranes are used as a step in combination with other separation technologies, such as cryogenic separation [20]. (An example of one of these processes is shown in Figure 10 in the next section.)

Figure 9: Simplified process flow diagram of a cryogenic distillation column producing high-purity CO_2 from a gasification-derived syngas



3.2.4 Cryogenic Gas Separation

Cryogenic gas separation technologies make use of the difference in boiling points or freezing points of different components in a gas mixture to achieve separation via phase change [31]. While a number of cryogenic separation process types exist, a mature technology with applications developed for CO_2-containing gas streams is cryogenic distillation. In cryogenic distillation, the gas stream being treated is compressed and cooled before undergoing an extractive distillation process in which species with lower boiling points are removed in the gas phase at the top of the column, while species with higher boiling points are removed in the liquid phase at the bottom of the column [32]. Depending upon what species are present in the gas stream, multiple distillation columns may be required. Cryogenic distillation has been developed commercially to remove CO_2 from natural gas, as the large difference in the boiling points of CO_2 and methane makes it relatively easy [33]. It is also a mature technology for the purification of H_2 produced in SMR and gasification processes, although as with other H_2/CO_2 separation technologies, the focus has historically been on optimizing recovery and purity of H_2 rather than of CO_2. Commercial processes have attained H_2 purity as high as 98% at a recovery rate of 95% [34]. Cryogenic distillation processes optimizing purification of CO_2 in H_2 production have been studied more recently; an example of such a process producing CO_2 from gasification syngas is shown in Figure 9.

In this example, the process gas from the gasification process contains primarily H_2 and CO_2, with H_2O, H_2S, CO, N2, and Ar present in smaller amounts. The incoming gas is refrigerated before entering a flash vessel where H_2O is removed as a liquid while the other species remain in the gas phase. This gas stream then enters the first distillation column, where H_2S is removed as a liquid along with any remaining water. The remaining gas stream exits the top of the column, is further compressed, and enters a second distillation column, where the final CO_2/H_2 separation occurs. While this example has thus far been developed via process simulation only, a CO_2 purity of over 99% was attained, with a capture rate of 85%. The H_2 product, however, had a purity of only 83%, with the balance being CO_2, N_2, CO, and Ar [35]. This demonstrates the challenge in using a cryogenic distillation process to achieve both a high-purity CO_2 and a high-purity H_2 product as well as high recovery rates for both species. For this reason, as well as the high energy demand associated with cryogenic gas separation, recent efforts have focused on the combination of cryogenic



"Recent efforts have focused on the combination of cryogenic distillation with other gas separation technologies, such as PSA and membranes."

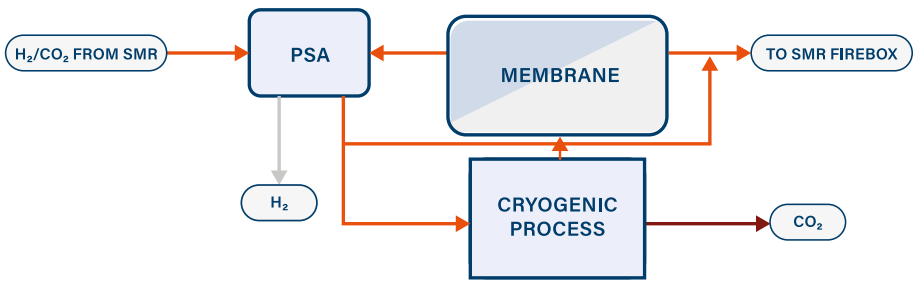
distillation with other gas separation technologies, such as PSA and membranes [34]. An example of this is the CryoCap™ H_2 technology developed by Air Liquide, which has been demonstrated on an SMR unit in Port-Jérôme, France, since 2015 [36]. A flow diagram for this process is provided in Figure 10.

In this process, the off-gas from the PSA goes to a cryogenic process that produces a CO_2 stream with a purity over 99.5%. The remaining gas stream from the cryogenic process then goes to a membrane separation unit to increase the recovery of H_2. The high-H_2 content stream leaving the membrane unit is recycled to the PSA unit, and the low-H_2 content stream goes to the SMR firebox to supplement the combustion fuel. In the Port-Jérôme case, only about two-thirds of the PSA off-gas goes to the cryogenic process, and the rest goes to the SMR firebox, as shown in Figure 10. However, this is based on the relatively low demand for high-purity CO_2, not on the technology's capability. Air Liquide reports a CO_2 capture rate over 97% as well as a 10 to 15% increase in H_2 production in comparison with the standard PSA-only configuration, in which all PSA off-gas would be sent to the SMR firebox, due to the added membrane recovery [36].

3.2.5 Oxy-fuel and Chemical Looping Combustion

In oxy-fuel combustion, fuel is combusted in the presence of pure O_2 (typically 95% purity or higher) diluted with recycled flue gas. This eliminates, or nearly eliminates, the presence of N_2 in the flue gas stream, making downstream gas separation to produce high-purity CO_2 much easier. As the proportions of CO_2 and H_2O in the combustion chamber are much higher than

Figure 10: Simplified process flow diagram of CryoCapTM H_2 process used in Port-Jérôme

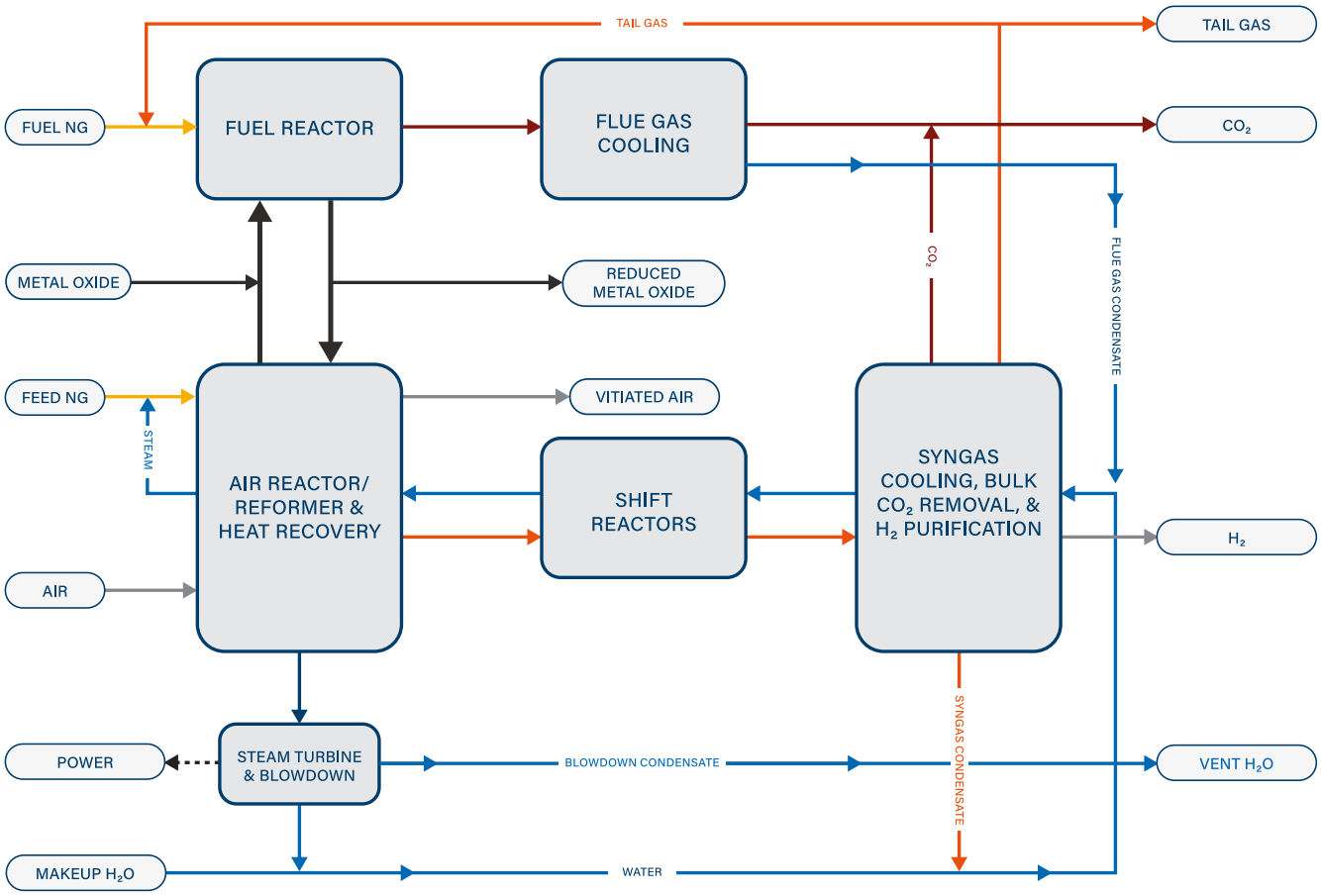


in typical air-fired combustion, the emissivity of the gas is higher, meaning that higher radiative heat transfer rates can be attained [37].

Using pure O_2 as the oxidant in place of air requires separation of O_2 from air, which is conventionally done in a cryogenic ASU. This entails a high energy penalty, consuming about 0.24 kWh/kg of O_2 at 95% purity. Promising alternatives to the cryogenic ASU include ion transport membrane reactors (ITMR) and chemical looping combustion (CLC). In an ITMR, O_2 is separated from air on the feed side of the membrane and combusted with fuel diluted in recirculated CO_2 on the permeate side of the membrane [38]. In CLC, direct contact between air and fuel is avoided through the use of a metallic oxygen carrier (typically iron, nickel, manganese, or copper-based) circulating between an air reactor and a fuel reactor [39]. In the air reactor, the oxygen carrier is oxidized, thereby separating O_2 from the air stream. In the fuel reactor, the oxygen carrier is reduced by the fuel, producing a stream of CO_2 and H_2O [40].

In the context of hydrogen production, variations of oxy-combustion technology have been proposed or are under development. Autothermal reforming, described in Section 3.1.3, is an example of an oxy-combustion hydrogen production process and is the most commercially advanced, with a 400 tonnes per day facility currently under development in Edmonton, Alberta [41]. Variations on the SMR process in which the reformer tubes are externally

Figure 11: Simplified process flow diagram of PCL-SMR



heated by oxy-combustion of natural gas, as opposed to conventional air-fired combustion, have also been proposed, but remain low on the development scale [42]. Similarly, integration of the SMR process with an ITMR has been proposed, but has yet to be developed beyond analytical studies [43]. The concept of using pressurized chemical looping (PCL) to drive the SMR process, referred to as PCL-SMR, has also been studied [39]. A simplified process flow diagram of PCL-SMR is presented in Figure 11.

In the PCL-SMR process, as in conventional SMR, steam and natural gas are reacted over a nickel catalyst in the tubes of the reformer. However, instead of heat supplied by direct combustion of natural gas in the reformer firebox, the heat is supplied in the air reactor/reformer via the exothermic reaction of the oxygen in air with the reduced form of a metal oxide. The metal oxide, now at a higher oxidation state, is then transferred to the fuel reactor, where it is reduced by natural gas, producing a flue gas stream comprised primarily of CO_2 and H_2O. This flue gas is then cooled to condense and remove the H_2O, producing a high-purity CO_2 stream. While the metal oxide is continuously circulated in the process, it does require purge and makeup in order to maintain reactivity.

3.2.6 Considerations for Selecting a Carbon Capture Technology

The carbon capture technologies presented in this section are all being studied or developed in some capacity for applications in CO_2 capture from hydrogen production. Chemical solvents for CO_2 capture in SMR and physical solvents for CO_2 capture in POx processes are commercially mature technologies for bulk CO_2 removal from syngas, although thus far they have not been applied for high-purity CO_2 production. PSA and cryogenic distillation have also been commercially developed for purification of H_2 from CO_2 [27], [34]. Other technologies described here are at lower stages of development for CO_2 capture applications but may offer benefits over more mature technologies. Things to consider when selecting a carbon capture technology for implementation at a given location include feedstock requirements; thermal and electrical energy input requirements; safety impacts on people, property, and environment; CO_2 capture rates; and CO_2 product purity.

Solvent-based absorption processes require the input of chemical solvents. Although the solvent is regenerated as part of the capture process, solvent degradation and environmental losses do occur over time, requiring continuous makeup of fresh solvent to maintain the CO_2 capture rate. Similarly, CLC requires continuous makeup of the metallic oxygen carrier due to attrition and deactivation of the material. Other processes, such as solid sorbent-based adsorption and membrane separation, require periodic replacement of the solid sorbents and the membrane modules. The operating life of these materials will depend on the operating conditions and the species present in the gas being treated.

Solvent-based absorption and TSA processes require thermal energy input to regenerate the solvent or sorbent being used. In most cases, this thermal energy is in the form of steam, although there are solvent-based processes under development that can use hot water in place of steam, potentially lowering the thermal energy requirement. At the scale required for CO_2 capture in SMR, for example, this steam is typically produced via combustion of natural gas. In mature amine capture processes, this has the drawback of consuming over 20% more natural gas than was initially being consumed by the process, depending on the capture rate [4]. In addition to the increase in non-renewable fossil fuel consumption, this also increases the quantity of CO_2 being produced, leading to a challenging optimization situation in which increasing capture rates lead to increased production of CO_2, as implied by the solvent regeneration energy requirement [18]. Other technologies, such as PSA, membrane separation, cryogenic separation, and oxy-fuel combustion, do not require additional thermal energy input. However, their electrical energy input requirements are very high, and thus increased fossil fuel consumption and CO_2 emissions may occur indirectly, depending on the source of the electricity being used.

The hydrogen production technologies discussed here are industrial processes operating under severe conditions (i.e., high temperature, high pressure), and thus the addition of a carbon capture facility should not significantly increase the safety risks related to these operating conditions [10]. However, the addition

of downstream CO_2 processing equipment, as opposed to directly venting the CO_2 to the atmosphere, can increase the risk of a CO_2 leak within the facility to some degree. At high concentrations, CO_2 is an asphyxiant and can pose a safety risk to facility operators. Further, there may be safety and environmental risks associated with the materials used in some processes, particularly with amine solvents. Many commercial solvents are inherently toxic, with amine slip occurring on the absorption side of the process leading to some atmospheric emissions of toxic species [44].

Technologies also vary widely in their capture rates and CO_2 product purities. Solvent-based absorption processes, solid-based adsorption processes, oxy-combustion, and PCL-SMR can produce CO_2 at a purity of over 95% and attain capture rates of 95% or higher, although, as previously noted, the optimization of capture in processes requiring thermal energy input can be complex. State-of-the-art membrane processes, on the other hand, are reaching maximum capture rates of 90%, with 60 to 80% being more realistically achievable and with CO_2 purity ranging from 70 to 90% [45]. Cryogenic distillation can provide high capture rates and very high product purity but requires the incoming stream to have an already high CO_2 content in order to do so. Processes that integrate multiple technologies with different capture abilities to overcome these limitations are being developed, such as the CryoCap™ technology described in Section 3.2.4.

3.3 Carbon Dioxide Transport, Utilization, and Geological Storage Technologies

For industrial CO_2 emitters considering implementing CO_2 capture at their facilities, the question of what to do with captured CO_2 is a priority. While CO_2 utilization can play a role in answering this question, large-scale geological sequestration of CO_2 will likely be required to avoid atmospheric emission of most industrially produced CO_2. Depending upon the emitter's location, CO_2 transportation may be required to reach a suitable storage or utilization location. CO_2 may be transported by pipeline, ship, rail, or truck [46]. An overview of the conditions required for transportation by each of these methods is provided in Table 1.

Table 1: Overview of required conditions for CO_2 transportation [47]

Transportation Method	CO_2 Conditions	CO_2 Transportation Phase(s)
Pipeline	4.8 to 20 MPa 10 to 34 °C	Vapour; dense, liquid; supercritical
Ship	0.7 to 4.5 MPa -52 to 10 °C	Liquid
Truck	1.7 to 2.0 MPa -30 to 20 °C	Liquid
Rail	0.7 to 2.6 MPa -50 to -20 °C	Liquid

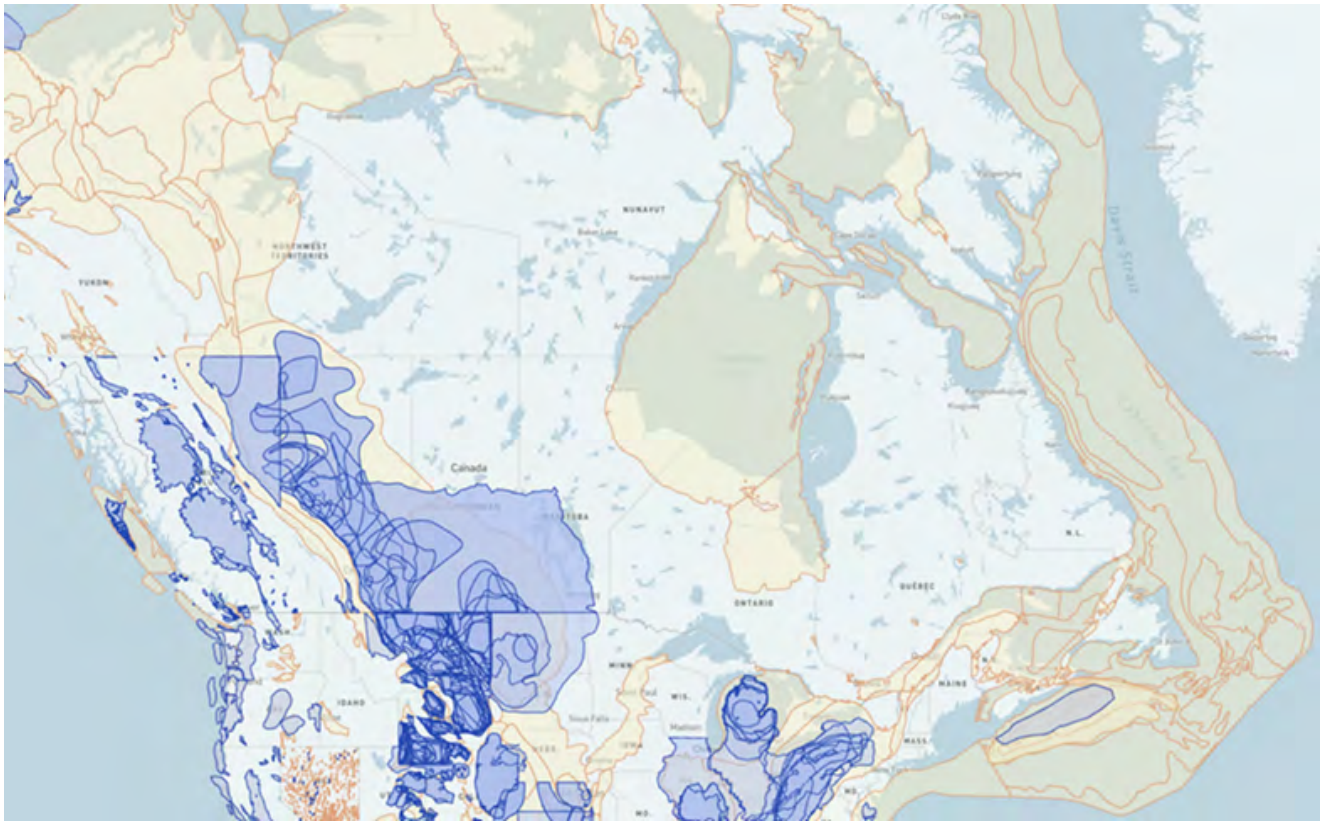
Currently, CO_2 pipelines are in operation around the world, including over 8000 km in the United States transporting around 66 megatonnes per year of supercritical CO_2 and an additional 100 km transporting gas-phase CO_2 [46]. In Canada, the Quest pipeline has been operating since 2015, and the Alberta Carbon Trunk Line became fully operational in 2020, with the capacity to eventually transport up to 14.6 megatonnes per year of CO_2 [20], [49]. While studies show that pipelines can offer the lowest operating costs and environmental impacts of the available transportation options, their high capital costs mean that large CO_2 capacity is required to attain the economy of scale that makes them economically viable. Transportation of CO_2 by ship has been employed over the last decade or so for food-grade CO_2 in vessels with capacities of 2000 tonnes or less [47]. Over longer distances it can be cost competitive with pipeline transport; however, the current use of marine diesel to power ships may make the environmental impact unfavourable compared with pipeline transport [47]. Over shorter distances, and for stranded CO_2 producers, truck or rail may be the most practical transportation solution [46].

Many options exist for CO_2 utilization, including mineralization in aggregates and concrete, chemicals and fuels synthesis, food and beverage industry applications, polymers, engineered materials, and agricultural feed. Many reports broadly categorize these

utilization pathways as either long-term or short-term CO_2 sequestration pathways based on the lifetime of the product, with lifetimes over 100 years considered long term. Concrete and aggregate production, some polymers, and engineered materials, such as carbon fibre, can have sufficiently long lifetimes to be considered long-term sequestration pathways, while products, such as fuels, will immediately re-release CO_2 to the atmosphere upon use, classifying them as short-term sequestration pathways. Currently, global annual CO_2 utilization is around 250 megatonnes per year, primarily for urea production and enhanced oil recovery (EOR) [46]. A 2018 study from the Global CO_2 Initiative estimated that this could grow to between 2 and 8 gigatonnes per year by 2050, with production of concrete, aggregates, and fuels becoming the primary utilization pathways and EOR no longer included [49].

Long-term storage of CO_2 requires geological reservoirs with sufficient porosity to hold CO_2, the permeability to accommodate the injection of CO_2, and impermeable caprock to prevent CO_2 leakage [46]. In Canada, the most storage potential lies in saline formations and sedimentary basins which, as seen in Figure 12, are primarily located in Western Canada, with smaller reservoirs in Southwestern Ontario and off the coast of Nova Scotia. A 2013 study estimated that Canada has between 48 and 320 gigatonnes of geological storage capacity available, primarily in saline formations [50]. As of 2022, approximately 4.8 megatonnes of CO_2 are being stored annually in Western Canada. Of this, 3.6 megatonnes are stored through CO_2-EOR, primarily in the Weyburn field in Saskatchewan, with the remaining 1.2 megatonnes stored in the Quest and Aquistore saline aquifer storage projects [51].

Figure 12: Saline formations (blue) and sedimentary basins (beige) in North America. Data sourced from the National Carbon Sequestration Database (NATCARB) Viewer [52]



3.4 Existing Standards and Guiding Documents Relevant to Carbon Capture in Hydrogen Production

A review of provincial, national, and international codes and standards did not yield results specific to CCS in hydrogen production. However, many standards are relevant and applicable to this topic and broadly categorized as follows for analysis:

- Codes and standards for carbon dioxide capture processes
- Codes and standards for carbon dioxide transportation
- Codes and standards for carbon dioxide storage
- Cross-cutting or broad topics related to CCS
- Project-wide environmental impacts

The following sections review codes and standards, technical reports, technical specifications, and standards currently under development in each of these subject areas, with a focus on the first category. The following abbreviations are used to identify the status of standards not yet issued or other items produced by the SDO:

- **AWI** Approved new Work Item (applicable to ISO standards)
- **CD** Committee Draft (applicable to ISO standards)
- **RP** Recommended Practice
- **TR** Technical Report
- **TS** Technical Specification

Documents relevant to carbon capture processes are summarized in Table 2, followed by carbon dioxide transportation in Table 3 and geological storage in Table 4. Documents on cross-cutting and broad topics related to carbon capture, transportation, and storage are presented in Table 5, while documents related to project-wide environmental impacts are summarized in Table 6.

Table 2: Standards and relevant documents for carbon capture processes

Designation	Title	Publication Year
DNV-RP-J201	Qualification procedures for carbon dioxide capture technology [53]	2021
ISO 14678	Hydrogen fuel quality – product specification [54]	2019
ISO/TS 19883	Safety of pressure swing adsorption systems for hydrogen separation and purification [55]	2017
ISO/TR 27912	Carbon dioxide capture – Carbon dioxide capture systems, technologies, and processes [56]	2016
ISO 27919-1	Carbon dioxide capture – Part 1: Performance evaluation methods for post-combustion CO_2 capture integrated with a power plant [57]	2018
ISO 27919-2	Carbon dioxide capture – Part 2: Evaluation procedure to assure and maintain stable performance of post-combustion CO_2 capture plant integrated with a power plant [58]	2021
ISO/TR 27922	Carbon dioxide capture – Overview of carbon dioxide capture technologies in the cement industry [59]	2021
ISO/CD 27927	Carbon dioxide capture, transportation and geological storage – Key performance parameters and characterization methods of absorption liquids for post-combustion CO_2 capture [60]	In progress
ISO/CD 27928	Carbon dioxide capture, transportation and geological storage – Performance evaluation methods for CO_2 capture plants connected with CO_2 intensive plants [61]	In progress

Table 3: Standards and relevant documents for carbon dioxide transportation

Designation	Title	Publication Year
DNV-RP-F104	Design and operation of carbon dioxide pipelines [62]	2021
ISO 27913	Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems [63]	2016
ISO/AWI TR 27929	Transportation of CO_2 by ship [64]	In progress
CSA Z662	Oil and Gas Pipeline Systems [65]	2023

Table 4: Standards and relevant documents for geological storage of carbon dioxide

Designation	Title	Publication Year
CSA Z741	Geological storage of carbon dioxide [66]	2012
DNV-RP-J203	Geological storage of carbon dioxide [67]	2019
ISO 27914	Carbon dioxide capture, transportation and geological storage – Geological storage [68]	2017
ISO 27916	Carbon dioxide capture, transportation and geological storage – Carbon dioxide storage using enhanced oil recovery (CO_2-EOR) [69]	2019
ISO/TR 27923	Carbon dioxide capture, transportation and geological storage – Injection operations, infrastructure and monitoring [70]	2022
ISO/CD TR 27926	Carbon dioxide enhanced oil recovery (CO_2-EOR) – Transitioning from EOR to storage [71]	In progress

Table 5: Standards and relevant documents on broad and cross-cutting topics related to carbon dioxide capture, transportation, and storage

Designation	Title	Publication Year
ISO 27917	Carbon dioxide capture, transportation and geological storage – Vocabulary – Cross-cutting terms [72]	2017
ISO/TR 27918	Lifecycle risk management for integrated CCS projects [73]	2018
ISO/TR 27921	Carbon dioxide capture, transportation and geological storage – Cross Cutting Issues – CO_2 stream composition [74]	2020
ISO/TR 27925	Carbon dioxide capture, transportation and geological storage – Cross Cutting Issues – Flow assurance [75]	2023

Table 6: Standards and documents relevant to project-side environmental impacts of carbon capture, transportation, and storage

Designation	Title	Publication Year
ISO 14021	Environmental labels and declarations – Self-declared environmental claims (Type II environmental labelling) [76]	2016
ISO/TS 14027	Environmental labels and declarations – Development of product category rules [77]	2017
ISO 14040	Environmental management – Life cycle assessment – Principles and framework [78]	2006
ISO 14044	Environmental management – Lifecycle assessment – Requirements and guidelines [79]	2006
ISO 14046	Environmental management – Water footprint – Principles, requirements and guidelines [80]	2014
ISO 14064-1	Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals [81]	2018
ISO 14064-2	Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements [82]	2019
ISO 14064-3	Specification with guidance for the verification and validation of greenhouse gas statements [83]	2019
ISO 14067	Greenhouse gases – Carbon footprint of products – Requirements and guidelines for quantification [84]	2018
ISO/TR 19870	Methodology for determining the greenhouse gas emissions associated with the production, conditioning, and transport of hydrogen to consumption gate [85]	2023
ISO/TR 27915	Carbon dioxide capture, transportation and geological storage – Quantification and verification [86]	2017
SA TS 5373	Carbon Dioxide Capture, Transportation and Geological Storage – Quantification and Verification of Emission Reductions [87]	2022

3.4.1 Carbon Dioxide Capture Processes

The International Organization for Standardization Technical Committee 265 (ISO/TC 265) for Carbon Capture, Transportation, and Geological Storage was convened in 2011 to prepare standards for the design, construction, operation, environmental planning and management, risk management, quantification, monitoring and verification, and other related activities in CO_2 capture, transportation, and geological storage [88].

In 2016, ISO/TC 265 issued Technical Report ISO/TR 27912, titled *"Carbon dioxide capture – Carbon dioxide capture systems, technologies, and processes"*, with the objective of reviewing existing capture technologies and processes to support the development of the subsequent series of standards [56]. The scope covers capture systems applicable to CO_2 point source emissions from industrial processes. The report classifies capture systems, identifies the applicable system boundaries, and then further breaks down CO_2 separation processes by type. This is followed by sections on CO_2 capture in an absorption process and ventilation in a process gas stream in the power generation industry, the cement production industry, the iron and steel industry, and industrial gas production processes including hydrogen production. ISO/TR 27922 further summarizes carbon capture technologies applicable to the cement industry that are currently under development [59].

ISO 27919-1 and ISO 27919-2 provide requirements for evaluating the performance of a post-combustion CO_2 capture (PCC) facility using liquid-based chemical absorption integrated with a power plant. Part I provides a basis for estimating, measuring, evaluating, and reporting on key performance indicators (KPI) for a PCC facility [57], while Part II provides formulas and methods for assuring and maintaining reliable performance [58]. These documents do not cover capture technologies other than post-combustion liquid-based chemical absorption. Specifically, ISO 27919-1 defines the system boundaries, parameters that describe the capture plant performance, utilities and consumption calculation approach, guiding principles for testing required to calculate the KPIs, standards applicable to instrumentation and measurement methods, and the calculation approach to evaluating the KPIs. The KPIs considered are specific thermal energy consumption (STEC), specific electrical energy consumption (SEC), specific equivalent electrical energy consumption (SEEC), specific reduction in CO_2 emissions (SRCE), specific absorbent consumption (SAC), and specific chemical consumption (SCC) [57]. While these KPIs were developed for a PCC facility in a power plant, they can be considered relevant and applicable to hydrogen production processes as well. However, the KPIs' definitions and boundary measurement points would need to be redefined as appropriate for this application, given the differences in process configuration and operation between power plants and hydrogen production facilities, and additional KPIs may need to be added. Two future new standards will provide requirements for absorption liquids for post-combustion CO_2 capture (ISO/CD 27927) and performance for CO_2 capture plants connected to CO_2 intensive plants (ISO/CD 27928) [60], [61].

ISO 14687 and ISO/TS 19883 provide guidance on hydrogen fuel quality and safety of PSA systems for hydrogen purification, respectively. While the detailed sampling and analysis methods in ISO 14687 are not directly relevant to carbon capture, the specifications for fuel quality can inform the selection and design of H_2/CO_2 separation systems.

DNV-RP-J201 is a Norwegian recommended practice document on qualification procedures for new CO_2 capture technologies applied to power generation from fossil fuels and covers post-combustion capture, pre-combustion capture, and oxy-fuel combustion. In this context, technology qualification refers to a systematic approach to risk management before and during implementing new technologies and is used to confirm that a technology will meet operation requirements within defined limits. The document introduces the philosophy and principles of technology qualification and describes the main steps in the process including developing the qualification basis, conducting the technology assessment and threat assessment, developing and executing the qualification plan, and conducting the performance assessment. An example of the qualification process for a post-combustion amine capture process on a natural gas combined cycle power plant is provided in an appendix. The example suggests critical parameters to assess in the qualification of CO_2 capture technologies, including CO_2 capture rate, heat and power consumption, solvent degradation rate, and CO_2 product composition [53].

3.4.2 Carbon Dioxide Transportation

It is important to acknowledge that there is currently a developed infrastructure for carbon dioxide transportation. In Canada, transportation of CO_2 is regulated by Transport Canada under the Transportation of Dangerous Goods Regulations, which addresses transportation via road, rail, marine, and air [89]. CO_2 is classified as a Class 2.2 non-flammable and non-toxic gas transported at an absolute pressure of 280 kPa or higher at 20 °C, or as a refrigerated liquid [89].

ISO 27913 provides requirements and recommendations specific to the transportation of CO_2 via pipelines from the inlet of pipeline from carbon capture facility to pipeline outlet to storage facility. It is intended to be used in conjunction with requirements of existing standards that cover pipeline transport of gas and liquids, such as CSA Z662, which outlines requirements for pipelines and includes provisions specific to CO_2 [65]. Within the boundaries, the standard addresses health, safety, and environment aspects of CO_2 transport and monitoring, and prescribes the requirement for the gas's properties and its mixtures that influence pipeline transportation, pipeline concept development and design criteria, materials and construction, operation, and requalification of existing

pipelines for CO_2 service. While it is not specific to transport of CO_2 captured from hydrogen-producing processes, it does provide guidance on considerations for the CO_2 stream exiting a capture facility. These considerations include temperature, pressure, phase, and presence of impurities in the CO_2 stream, including oxygen, water, nitrogen, hydrogen, and sulphur species. While specific requirements will depend on the project and the pipeline being considered, ISO 27913 provides indicative levels of both CO_2 and several main impurities in the CO_2 stream, identifies the importance of adequate dehydration of the CO_2 stream, and notes the requirement for pipeline design review in the case that a CO_2 stream from a new project is proposed to be connected [63].

DNV-RP-F104 is a Norwegian recommended practice document for the design, construction, and operation of CO_2 pipelines with the intent of providing consistent safety requirements. Among other topics, it covers the specific properties of CO_2 as well as safety aspects of CO_2 transport by pipeline relevant to the context of CO_2 capture [62].

As noted, ISO/AWI TR 27929 is an in-progress report on the topic of CO_2 transportation by ship. Requirements for transportation by ship will be important for CO_2 capture facility operators to understand in cases where CO_2 is exported for utilization or storage. Other modes of transportation, particularly rail, may also be of interest in cases where facilities are small scale or too remote for pipelines to be economically feasible [64].

3.4.3 Carbon Dioxide Geological Storage

In Canada, geological storage of CO_2 is provincially regulated. The most advanced jurisdiction with respect to CO_2 storage is Alberta, where it is regulated by the Alberta Energy Regulator. Provincial legislation specifies that the Crown owns the pore space in which CO_2 is injected and is accountable for long-term liability and enables the Government of Alberta to issue evaluation permits, agreements, and leases for CO_2 storage [55]. Saskatchewan also has regulations in place that allow the province's Ministry of Energy and Resources to authorize CO_2 storage projects [90]. At the end of 2022, British Columbia received federal approval of their proposed CO_2 storage regulations, which are administered by the Ministry of Energy, Mines, and Low Carbon Innovation [91]. Other provinces are not as advanced in this area, although some are in the process of developing regulations for CO_2 storage. For example, in Ontario in 2022, the provincial government proposed changes to the Oil, Gas, and Salt Resources Act, which currently prohibits geological storage of CO_2. This proposal was the first step toward designing a framework to regulate CO_2 storage projects on Crown and private land in Ontario [92].

First released in 2012, CSA Z741 was the first performance standard for the geological storage of CO_2 in sedimentary basins [93], [66]. It served as the seed document for ISO 27914, which was issued in 2017 [93]. These standards, which outline requirements on storage site screening and selection for the minimization of risks to the environment and human health, may be of relevance to CO_2 capture in hydrogen production, as project proponents will need to consider their proximity to a storage site that meets the requirements [66], [68]. Similarly, DNV-RP-J203 is a Norwegian recommended practice that provides a systematic approach to the selection, qualification, and management of geological CO_2 storage sites to ensure environmentally safe, long-term CO_2 storage [67].

ISO 27916 is specific to quantifying and documenting the total amount of CO_2 stored in association with CO_2-EOR, while ISO 27923 covers CO_2 injection activities in association with both storage in saline aquifers and CO_2-EOR. The quantification under ISO 27916 could be used as part of a broader quantification and verification of reductions in CO_2 emissions across an entire CCS project, including in hydrogen production applications [69], [70].

3.4.4 Cross-Cutting and Broad Topics

ISO 27917 provides comprehensive definitions of terms related to CO_2; CO_2 capture, transportation, and storage; monitoring and measuring performance in capture and storage; risk; and stakeholder relationships [72]. Should a standard for CO_2 capture technologies in the hydrogen industry be developed in the future, ISO 27917 could provide the basis for common understanding of the terminology it would use.

ISO/TR 27918 is a technical report with a focus on overarching and cross-cutting risks that can affect multiple or all stages of a CCS project. It is intended to support the potential future development of an ISO standard addressing life cycle risks for integrated CCS projects. Such a standard would provide guidance on procedures for identifying, evaluating, and mitigating risks in order to help project developers meet permitting requirements and to potentially inform future regulatory development [73].

ISO/TR 27921 is a technical report on the composition of the CO_2 stream leaving the capture facility. It reviews typical impurities found in CO_2 streams produced in different industries, looks at the potential impacts of these impurities on downstream transportation and injection operations, describes parameters to measure and monitor the stream composition, and addresses integration challenges. Specifically, the report looks at the composition of CO_2 captured at H_2 production plants based on SMR and provides an example composition of a CO_2 stream produced at an SMR facility in Japan employing PSA for H_2/CO_2 separation followed by an amine scrubbing process capturing CO_2 from the PSA off-gas. This particular facility stream has a CO_2 content of 99.7 vol%, with the major impurity being residual H_2 (0.22 vol%). Impurities in CO_2 captured from SMR H_2 production tend to be low, as the feedstock natural gas is typically pre-treated to remove contaminants in order to prevent reformer catalyst poisoning [74].

ISO/TR 27925 is a technical report on the topic of flow assurance in carbon capture, transportation, and storage. In this context, the purpose of flow assurance is to maintain a continuous CO_2 supply from a capture facility, through a transportation system, and into a geological storage reservoir and to demonstrate that all foreseeable operating modes, both intended and unintended, are predictable, reliable, and safe. While much of the document applies to the transportation, injection, and storage components of the CCS project, it also identifies the importance of the composition of the CO_2 stream and the presence of impurities in modelling the thermodynamic properties that will impact fluid behaviour and flow properties. It addresses the role that processes within the CO_2 capture facility as well as the efficiency of the overall capture process play in determining the composition and mass flow rate of the produced CO_2 stream [75]. The continuous nature of hydrogen production processes suggests that under normal operating conditions, fluctuations in CO_2 flow and composition should be minimal. However, as the document notes, consideration must be given to potential deviation from normal operating conditions and the impact that these deviations may have on the produced CO_2 stream.

3.4.5 Project-Wide Environmental Impacts

Given that the purpose of implementing CCS in hydrogen production is to reduce the CI and climate impact of hydrogen, a standardized approach to assessing the reduction in GHG emissions attained by a project will be important. Many standards exist covering topics related to life cycle assessment, environmental management, and quantification and verification of GHG emission reduction claims.

ISO 14021, ISO 14027, ISO 14040, ISO 14944, ISO 14046, ISO 14064-1, 2, and 3, and ISO 14067 are under the responsibility of ISO Technical Committee 207 for Environmental Management. They are not specific to either hydrogen production or CCS; however, they provide important guidance on assessing and reporting on product environmental impacts.

ISO 14040 and ISO 14044 provide the principles, framework, requirements, and guidelines for conducting life cycle assessments (LCA) [78], [79]. In the context of hydrogen production with CO_2 capture, an LCA can help to identify steps in the process where environmental performance can be improved, make comparisons between the environmental performance of different processes or pathways, and produce environmental product declarations. The guidance on defining an LCA's goal and scope as well as selecting a functional unit will be of particular importance, as the end-use of hydrogen may be important in studies that compare different production pathways. If the intended end-use of hydrogen is in a combustion application, it may be practical to use megajoules of fuel as a functional unit and include the combustion process



"Given that the purpose of implementing CCS in hydrogen production is to reduce the CI and climate impact of hydrogen, a standardized approach to assessing the reduction in GHG emissions attained by a project will be important."

within the scope in order to facilitate comparison of environmental impacts with other combustion fuels such as natural gas. On the other hand, if the intended end-use is in chemical synthesis, it may be more practical to use kilograms or tonnes of hydrogen as a functional unit and to include the chemical synthesis process within the scope to identify potential synergies. For example, ammonia production requires both hydrogen and nitrogen as process inputs. Oxy-combustion hydrogen production processes, such as autothermal reforming or PCL-SMR, produce a waste stream of vitiated air that typically contains over 97 vol% nitrogen. The potential to integrate this waste stream in the hydrogen end-use process may be important in comparing the environmental performance of different hydrogen pathways.

ISO 14046 provides further details specific to water footprint assessments based on LCA principles [80]. As described in sections 3.1.1 and 3.1.3, water is a major feedstock in reforming processes for hydrogen production. Adding a CO_2 capture process to a reforming process may change the water balance in the facility, as the water condensed from the flue gas stream during capture can potentially be recycled within the process. As such, including water footprint assessments in LCA studies of hydrogen production processes will provide valuable information on potential environmental benefits beyond reduction of GHG emissions.

ISO 14021 specifies the requirements for environmental claims regarding products, describing common terms and qualifying their use as well as providing a general evaluation and verification methodology for such claims [76]. ISO/TS 14027 specifically provides principles, requirements, and guidelines for developing product category rules for environmental Type III declarations based on LCA according to ISO 14040 and ISO 14044 [77].

ISO 14064 parts 1, 2, and 3 specify principles and requirements for quantification, monitoring, and reporting on GHG emissions reductions and removals as well as the verification and validation of GHG statements. They are applicable to organization, project, and product emissions reductions and statements [80]–[82]. ISO 14067 is based on the guidance identified in ISO 14040 and 14044, and sets specific requirements for the quantification of a product's carbon footprint [84]. This can allow hydrogen producers to seek independent verification of their reported product carbon footprint and provide accurate and transparent information to stakeholders. In Alberta, these topics are also covered by the Technology Innovation and Emission Reduction regulation, which is applicable to facilities emitting over 100,000 tonnes of CO_2 [94].

ISO/TR 27915 is a technical report that reviews best practices for quantification and verification of GHG emissions and reductions at the project level, covering

capture, transport, and storage of CO_2. Topics include project boundaries; the composition of the CO_2 stream and requirements for measuring and verifying it; identification, quantification, and reporting of GHG emissions and reductions; objectives, methodologies, and strategies for sampling and monitoring; verification against agreed criteria; and LCA of integrated CCS projects [86]. SA TS 5373 is a technical specification developed by Standards Australia covering a similar scope to ISO/TR 27915 [87].

Further to this, Bureau de normalisation du Québec (BNQ) and CSA Group are developing a bi-national (Canada and USA) standard, CAN/BNQ 1789-200, for the quantification and verification of the CI of hydrogen production. The purpose of this standard will be to provide a mechanism to accurately and consistently determine the emissions profile of a hydrogen production process [95], [96]. ISO also intends to produce a standard on defining the GHG intensity of hydrogen production. The standard will be based on the GHG quantification methodology developed by the International Partnership for Hydrogen and Fuel Cells in the Economy [97], [98]. As this process will take many years, in the interim they have developed a Technical Specification ISO/TS 19870, Methodology for determining the greenhouse gas emissions associated with the production, conditioning, and transport of hydrogen to consumption gate [85].

3.5 Potential Gaps in Codes and Standards

As noted at the beginning of Section 3.4, no codes or standards specific to CCS in hydrogen production were identified, although many aspects of CCS in hydrogen production are covered by the standards reviewed in this report. Nonetheless, some potential gaps remain where additional standardization could be beneficial.

Standards covering the performance of CCS technologies in hydrogen production were not found in the literature. Such standards should provide requirements for KPIs of these technologies similar to those outlined in ISO 27919 for solvent-based post-combustion CO_2 capture integrated with a power plant: STEC, SEC, SEEC, SRCE, SAC, and SCC. The definitions of these KPIs should be modified as necessary to apply to hydrogen production processes and additional CO_2 capture processes, and additional KPIs should be added, as necessary. For example, the definition of STEC given in ISO 27919 only accounts for thermal energy in the form of steam supplied to a solvent-based CO_2 capture process. In a hydrogen production process such as SMR, it may be practical to also account for thermal energy in the form of natural gas or other fuel crossing the system boundary, as steam production may be partially or fully integrated with the hydrogen production process and therefore within the system boundary. The calculation of the SEC, SEEC, and SRCE may also need to be modified slightly, as by definition they are specific to post-combustion capture facilities, and additionally the SEEC accounts for the derating of the power plant due to the steam requirement for amine regeneration. The SAC would not apply to CO_2 capture processes other than absorption-based processes, and thus may not necessarily need to be included. For all of these metrics, the standard(s) should be intentional in defining which steps in the overall process should be attributed to hydrogen purification and which should be attributed to CO_2 capture. For example, in the CryoCap™ process shown in Figure 10, the PSA and membrane steps could be attributed to hydrogen purification and thus their inputs (e.g., electrical power) would be excluded from calculations of CO_2 capture performance. The cryogenic separation step, on the other hand, could be attributed to CO_2 capture and included in performance calculations. Additional performance metrics could include the total fossil fuel consumption, the total water consumption, and the total atmospheric emission of pollutants other than CO_2. These metrics may vary widely with different CO_2 capture technologies. Comparative metrics such as change in total fossil fuel consumption relative to the base process (i.e., hydrogen production without CO_2 capture), change in total water consumption relative to the base process, and change in total atmospheric emissions of pollutants relative to the base process could also be valuable, as these may also vary between capture technologies and be relevant to the hydrogen production context. For example, with conventional amine capture systems, the total fossil fuel consumption may increase relative to the base process due to the thermal energy required for solvent regeneration. However, in an oxy-

combustion or PCL-SMR process, the total fossil fuel consumption may decrease due to an increase in heat transfer efficiency between the SMR firebox and the reformer tubes. Similarly, the addition of a CO_2 capture process may increase the quantity of water being recycled within an SMR process, reducing the fresh makeup water requirement. Likewise, an amine capture facility might introduce additional atmospheric pollutant emissions due to amine slip from the absorption column, but an oxy-combustion or PCL-SMR process might reduce overall NOx emissions due to the exclusion of N2 from the combustion chamber. Finally, process inputs to other CO_2 capture technologies, such as solid sorbents or enzymes for solvent enhancement, may need to be considered separately from absorbent and/or chemical consumption depending on the specific definitions used.

Standards on life cycle assessment such as ISO 14040 and 14044 provide comprehensive guidance applicable to all environmental indicators, including GHG emissions. Others, such as ISO 14046 and ISO 14067, provide guidance specifically on quantifying the water footprint and the carbon footprint of a product or process. A standard specific to quantifying the life cycle environmental impacts associated with a CO_2 capture project remains to be developed. ISO/TR 27915 may serve as a useful reference document in the development of a standard specifically for quantification and verification of GHG emission reductions from CO_2 capture projects; in Australia, this is covered by technical specification SA TS 5373. In the hydrogen production context, this may effectively be covered by the forthcoming CAN/BNQ 1789-200 or forthcoming ISO standard quantifying the CI of hydrogen production processes. Other standards specific to quantification and verification of CO_2 capture project environmental impacts, such as water consumption, fossil fuel consumption, and emissions of toxic substances, may need to be developed.

The definitions of the system boundaries should be established for CCS technologies in hydrogen production in order for producers to understand how to correctly apply standards on this topic. This is less straightforward than the case of PCC integrated with a power plant, given that CO_2 separation from H_2 is already an inherent part of most hydrogen production processes. A suggestion for this system boundary in the case where an absorption process is used for CO_2 capture is given in ISO/TR 27912; however, this report notes that other CO_2 capture methods are not within its scope and therefore this system boundary definition may not be broadly applicable.

The scope provided for ISO/CD 27928 on performance evaluation methods for CO_2 capture plants connected with CO_2 intensive plants suggests that it may cover some or all of these discussed gaps, as it identifies a methodology for calculating KPIs and the requirement for definition of the system boundaries as being part of this forthcoming document. It remains to be seen whether hydrogen production facilities will fall within the scope of this document, or whether they will be covered under a future standard built upon the foundation of this one.

The requirements for technology qualification are described for CO_2 capture technologies in DNV-RP-J201. While it is limited in scope to capture technologies integrated with power generation facilities, the methodology described appears broad enough to cover applications in other facility types, including hydrogen production. A standard with similar content applicable in Canada, whether developed nationally or internationally, could be beneficial in managing the risks associated with implementing new technologies in hydrogen production processes.

Workshop participants noted that standardization of a technology's capture rate may be required; while ISO 27919-1 provides the calculation methodology to determine the capture rate for an amine facility, it is not prescriptive in defining a minimum rate required, as this would be up to the jurisdiction in which the facility is located. Further, ISO-27919-1 makes reference to many standards that provide guidance and methodologies for gas sampling and measurements including flow rate, composition, temperature, and pressure. Given the significant differences between flue gas and syngas, particularly in pressure and composition, a similar standard developed for carbon capture in hydrogen production should ensure to reference standards relevant to measurement of syngas in the same way that ISO 27919 references standards relevant

to measurement of flue gas. For example, ISO 27919 references standards to provide guidance on measuring outlet flue gas composition by measuring CO_2, H_2O, and O_2 content. However, in an SMR process with CO_2 capture, if the PSA tail gas is not fully recycled, or if an amine capture process is used, there may be a vented process gas stream comprising primarily CO_2, H_2, CO, and CH_4. Additional guidance on measuring these gas species may be required.

Finally, it should be noted that all standards reviewed on the topic of CO_2 capture were specific to processes where a CO_2 stream is being produced as a by-product. As such, natural gas decomposition, which produces solid carbon instead, is not within the scope of any of these standards. If further commercial development of this technology were to proceed, standards addressing the calculation of KPIs for this process could be beneficial.

4 Conclusions

A suite of technologies exist for the production of hydrogen from carbon-based feedstocks, including SMR, POx, autothermal reforming, and natural gas decomposition. Likewise, a number of carbon capture technologies exist that can be applied to reduce CO_2 emissions from hydrogen production processes, either individually or in combination. These carbon capture technologies vary widely in their characteristics, including thermal energy consumption, electrical energy consumption, safety and environmental risks, CO_2 capture rate, and CO_2 product purity.

While a number of standards exist on the topic of CO_2 capture, standards specific to CCS in hydrogen production do not currently exist, although there may be standards forthcoming that address this topic. Areas for standardization could include technology qualification and performance assessment, with focus on net changes in fossil fuel consumption, electrical energy consumption, water consumption, chemical consumption, atmospheric CO_2 emissions, and other atmospheric pollutant emissions. Given that the inherent purpose of CCS in hydrogen production is to reduce GHG emissions, it makes sense to look at this from a life cycle GHG emission basis. It is recommended that any standards developed specifically for CCS in hydrogen production be consistent with standards on life cycle assessment and CI of hydrogen.

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