GEOLOGICAL CO_2 STORAGE IN SOUTHWESTERN ONTARIO: A Road Map for CCUS deployment in Ontario

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EXECUTIVE SUMMARY

Geofirma Engineering Ltd. (Geofirma) was retained by CanmetENERGY to prepare this Road Map to assist the adoption of Carbon Capture and Storage (CCS) systems in industrial southwestern (SW) Ontario by 2030, which is the Federal target date for 40-45% CO_2 emissions reduction Canada-wide.

Based on a review of emission data for SW Ontario, the industry and utility sectors emitted nearly 25 MT of CO_2 in 2020, with the vast majority, or around 20 MT, contributed by SW Ontario's manufacturers. The largest emitters were iron and steel mills (~7 MT), oil refineries (~4 MT), and natural-gas powered generation facilities (~4 MT). Other significant sources of emissions originated from chemical manufacturing (~4 MT) and cement and lime production (~2.5 MT). These industries are clustered in areas across SW Ontario indicating that they and other emitters will pose expensive capture and complex gathering and transportation problems. It is anticipated that perhaps only 30% of the 2020 CO_2 emissions from many facilities will require capture and geological storage because of electrification of industrial facilities and fuel replacement. For example, the food and beverage manufacturers and automobile producers are planning to eliminate their carbon emissions primarily through energy efficiencies (e.g., by switching to renewable energy sources), as well as other process improvements. Some industrial facilities will no doubt close because of the re-ordering of the North American industrial economy prompted by the US Inflation Reduction Act of 2022. Based on the analysis and discussions with industry representatives, it is estimated that around 10 MT of CO_2/year may be captured in SW Ontario by 2030 based on the field demonstration of proven geological storage.

The capture of emissions from the industrial facilities in SW Ontario will be strongly influenced by the cost and availability of carbon capture technologies. Chemical absorption with amine solutions is the most mature carbon capture technology available today, although oxy-combustion may prove to be the most promising for 2030. However, amine systems are often too expensive (i.e., with no viable business case) and may not be optimal for all industries. While other newer technologies, such as various forms of physical separation, membranes, solid looping, and inherent or direct CO_2 capture, offer potential capital and operational cost savings, these systems are less mature technologically and commercially, with high uncertainty in capture costs, rates, and implementation timelines. Therefore, further research and development is urgently needed (e.g., in the form of pilot plants and demonstration projects) to reduce the cost of CO_2 capture and to increase the technology readiness level of emerging technologies. It is also important to recognize, however, that the lack of CO_2 transport and storage infrastructure can be a more critical barrier to deployment of CCS than the availability of suitable carbon capture technology.

Industries are also aiming to cut costs by curbing their emissions through energy conservation and efficiency improvements, including electrification and switching to hydrogen-based fuels. While there is high potential for electrification in many industrial heating applications, electrically powered equipment offers no productivity or efficiency advantage over equipment powered by fossil fuels, resulting in little financial incentive to replace the equipment. Industry electrification would also require vast amounts of renewable energy, particularly to produce green hydrogen, which would be challenging to develop. In the short term, blue hydrogen is poised to serve as a bridge until more green hydrogen becomes available, with the Sarnia-Lambton region identified as a potential hydrogen hub, given not only its proximity to existing or new salt caverns for underground storage of hydrogen, but also the large

concentration of CO_2 emitting industries and hydrogen consumers in the area. The captured CO_2 would require a suitable storage site; geological storage in Essex County appears possible but is unproven.

The transportation of CO_2 in SW Ontario is challenged by the spread of the various large emitters around the region. It is expected that transportation by pipeline would be the preferred choice, however, this can be costly and will also require corrosion-resistant steels and pre-treatment to strictly limit the amounts of impurities in the gas stream. While road and rail CO_2 transport are even more expensive than pipelines, water-borne transport (i.e., by specially-constructed lakers) may be cost comparable and offer an attractive solution to the major emitters in Ontario, as many of them are located along or near the shores of the Great Lakes.

In terms of geological storage, there has been little progress towards identifying the potential CO_2 storage capacity beneath SW Ontario since Shafeen's 2004 study. Without numerous boreholes that have been completed within the potential CO_2 storage reservoirs and then characterized by in-situ hydraulic testing, it is impossible to provide reliable estimates of storage capacity at any one site. In general, sandstone aquifers have been the preferred choice of saline formations for dedicated geological CO_2 storage, and this includes the basal Cambrian sandstone formation that overlies the Precambrian basement of granitic rocks in SW Ontario. The pioneering work of Shafeen had identified a large CO_2 storage capacity in the Cambrian formation along and beneath the shore of Lake Erie. However, with the experience gained from 20 years of CO_2 storage across the world, these estimates now appear overly optimistic, and do not account for the inefficiency of storage during CO_2 injection operations, i.e., due to factors such as gravitational segregation due to CO_2's buoyancy, high-permeability channeling, capillary blockage, viscous fingering, and brine pressurization. As a working estimate, injection wells completed in the Cambrian sandstone beneath SW Ontario appear likely to sustain an injectivity of only ~200 kilotonnes of CO_2 per year. Therefore, to refine geological storage estimates across SW Ontario, there is an urgent need to perform site characterization of the Cambrian formation through test wells that can confirm or revise such injectivity rates and the associated brine pressure responses.

In the short term by 2026, it is recommended that at least three sites be investigated along the north shore of Lake Erie, where injection of CO_2 into saline aquifers might be undertaken, the results analyzed, and an initial 10 million tonnes per year (MT/yr) of CO_2 storage is proven to catalyze CCS decisions by industry. Assuming an injectivity of 200 kT CO_2/well/year, 50 injection wells will be required to store 10 MT each year.

In addition to 18 specific RD&D needs listed in section 6 that require addressing by industry, government, and academia before 2030, the following general recommendations are made:

1: The federal and provincial governments ensure the proven availability of 10 MT/yr of geological CO_2 storage capacity by late 2025 in SW Ontario to allow manufacturing industry to proceed with FIDs regarding carbon capture and to commit to pipeline construction. To be achieved by late 2025.

2: Consideration should be given to the possibility of laker (i.e., specialized ships) transportation of CO_2 through the Great Lakes system as an insurance should geological CO_2 storage fail to meet current expectations and to provide a lifeline to industrial emitters distant from potential geological storage hubs. To be achieved by 2028**.**

3: Exploratory drilling and formation testing of the Cambrian sandstone be undertaken in high priority potential areas along the north shore of Lake Erie during 2023-2025 to establish proven geological storage for CCS hubs and to measure in-situ stresses. These sites are in Essex, Norfolk and Haldimand Counties. They should be developed as test sites where 1 km deep boreholes would be drilled, cored and tested for their suitability to become CO_2 injection wells. To be achieved by late 2025.

4: An RD&D test site should be developed in SW Ontario, at one of the three sites mentioned above, to demonstrate the steps required for proven storage including the pilot testing of CO_2 injection. To be achieved in 2025.

5 Reservoir engineering research, development, and demonstration should be supported to determine how to best manage the pressurization of the Cambrian sandstone during CO_2 injection, whether that be in western or eastern Canada. To be achieved by 2028.

6: The completion of the geophysical exploration of existing faults along the north shore of Lake Erie is critical, especially to detect and characterize basement faults. To be achieved by late 2025.

7: Federal, provincial, and local authorities should initiate a public outreach and education programme to inform Ontarians about CCS. To be achieved in 2024.

It is regrettable that, although Ontario began in 2006 to consider how to implement CCS, the provincial government lost interest after the shut-down of the coal-powered generating capacity of OPG in 2013. While it is certainly true that many field and laboratory techniques can be adopted from experience elsewhere, particularly from Alberta, there is much to be learned in how best to proceed in SW Ontario.

Proving sustainable geological storage at three sites of 10 MT/yr by late 2025 appears to be a prerequisite to allowing financial and operational planning by industry to commit carbon capture and pipeline construction by 2030, when the carbon tax is due to reach $170/tonne emitted. These three sites are chosen (see section 5.5) on the basis of their favorable hydrogeological properties. Failure to commence industrial CCS activities and to accelerate provincial policy and regulatory development in 2023/4 may result in decarbonization by deindustrialization of parts of the Ontario economy by 2030.

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APPENDIX B Acknowledgement: Individuals thanked for their professional opinions and the information provided to the authors during the preparation of this Road Map

APPENDIX C Workshop Report: Geological CO_2 Storage in Ontario: Addressing Regulatory Uncertainties, by Professor Neil Craik, October 2022

LIST OF ABBREVIATIONS

ATR	Auto-Thermal Reforming
BD3	Boundary Dam Power Plant unit 3, SaskPower
BF	Blast Furnace
Bgs	below ground surface
BOF	Basic Oxygen Furnace
CAPEX	Capital cost expenses
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and (geological) Storage
CCUS	Carbon Capture, Utilization, and Storage’
CH_4	Methane, the principal component of natural gas
CO_2	Carbon Dioxide
CO	Carbon Monoxide
DOE	US Department of Energy
DRI	Direct Reduction of Iron Ore
EAF	Electric Arc Furnace
EOR	Enhanced Oil Recovery

EU	European Union
FCC	Fluid Catalytic Converter
Fm.	Geological Formation
GS	Generating Station
H_2	Hydrogen
IEA	International Energy Agence
ITC	Investment Tax Credit
kT/yr	kilotonnes per year
MT/yr	Million tonnes per year
NETL	National Energy Technology Laboratory (of the US DOE)
N_2O	Nitrous Oxide
OPEX	Operational cost expenses
PSA	Pressure Swing Adsorption
PV	Pore Volume
R&D	Research & Development
RD&D	Research, Development & Demonstration
RFG	Refinery Fuel Gas
SMR	Steam Methane Reformer
SW	SouthWestern
T	Tonne (metric)
TSA	Temperature Swing Adsorption
VSA	Vacuum Swing Adsorption

1 INTRODUCTION

Geofirma Engineering Ltd. (Geofirma) was contracted by CanmetENERGY to carry-out a road mapping study to engage with key stakeholders in industry, academia, and governments to chart a path forward for the deployment of CCUS technology in Ontario to advance geological CO_2 storage in Southwestern (SW) Ontario by 2030 to meet emissions reductions targets. This Road Map is a strategic plan outlining activities that industry, governments, and academia might undertake before 2030 to enable the achievement of the Federal 2030 CO_2 emissions objectives assuming industrial and federal funding and other resources are available, and the provincial government issues a policy and regulatory framework to address geological CO_2 storage. As such, the Road Map can be updated over time. The area of interest of this Road Map – SW Ontario – is defined in Figure 1-1.

1.1 Background

In April 2021, the Government of Canada established a deadline of 2030 to reduce Canadian greenhouse gas (GHG) emissions by 40-45% relative to 2005 emissions. Carbon capture and (geological) storage (CCS) offers a crucial strategy for reducing CO_2 emissions from heavy industry. However, this implies that a wide variety of technical, social, and economic issues associated with carbon capture, processing, transportation, and geological storage must also be resolved prior to 2030.

Government of Canada data[1] show that manufacturing industry in SW Ontario produces ~20 MT/yr (million metric tonnes per year) of CO_2 emissions. These emissions are from iron and steel production, oil refining and petrochemicals, cement & lime production, electricity generation and automobile manufacturing. These are listed in Table 1-1 together with other fixed-site emitters, principally electrical generating utilities, that bring the total for the area to approximately 25 MT/yr. Because SW Ontario is a diversified industrial economy, it produces many of the basic industrial commodities used throughout the Canadian economy and exported to the USA. It requires a particular set of solutions to its carbon capture and storage needs.

Worldwide, heavy industry is uniquely challenged by decarbonization; this is no different in Ontario. A report from the Brookings Institute[2] indicated that steel, cement and chemicals produce 40% of global industrial CO_2 emissions while being essential to the building of infrastructure in the low-carbon economy of 2050. Therefore, Brookings points out that steel, cement, and lightweight, durable plastics will remain critical components of any future Canadian industrial economy. SW Ontario is a major producer of all three industrial products. Hence, it is also a major generator of CO_2 emissions.

A set of CCS solutions for Ontario's heavy industry will have to reflect how international trade in these commodities is changing because of the anticipated increase in Canadian CO_2 emission prices and potential border adjustment tariffs instituted by the USA and the European Union. It should also reflect

[1] https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/facility-reporting/data.html

[2] Gross, S, 2021. *The Challenge of Decarbonizing Heavy Industry.* Brookings Institute, Washington DC, USA.

how rapid improvements in CCS technologies are occurring worldwide. These improvements will no doubt be driven through a learning-by-doing process between now, 2030 and beyond.

In November 2021, the International Energy Agency[3] identified over 100 new carbon capture facilities had been announced worldwide in 2021 alone and that the carbon capture of operating facilities had tripled since 2010 to over 40 MT/yr. An example of this progress is the operation of the Quest project in Alberta, where operating costs of ~$40/tonne of stored CO_2 have now dropped to ~$25/tonne. Furthermore, it is anticipated that the capital cost of such a facility, which captures and stores ~ 1 MT of CO_2 per year, would now cost about $80/tonne as opposed to initial estimates of $120/tonne[4].

There is a strong argument that, to limit global temperature increase by ≤2°C by 2050, CCS will be required. The IPCC 2014 Fifth Assessment Report[5] concluded that to keep global temperatures below 2°C implies reducing emissions by 40-70 per cent from 2010 values by mid-century. Furthermore, the IPCC indicated that to achieve 2°C without the use of CCS requires 2.5 times greater global expenditure[6] than if CCS is widely used throughout the global economy. Or, as Haszeldine and Singh Ghaleigh[7] put it*: "No CCS = No 2°C*"." In October 2022, the Copenhagen Climate Centre of the United Nations Environment Programme[8] (UNEP) released its assessment of progress towards the expected progress through to 2030 and concluded that there was inadequate action on the climate crisis leaving the 2°C scenario in doubt. Therefore, it is reasonable to expect increased efforts by the Federal Government to ensure its 2030 40-45% decarbonization objective is met.

However, the technology of carbon capture, utilization, and storage (CCUS) has many social critics. As the Brookings Institute has observed: "*although CCUS is likely to play an important role in deep decarbonization of the economy, the most environmentally-minded citizens are least supportive of the technology*"[9]. This became evident in Canada in early 2022 when over four hundred academic scholars – mainly social scientists – issued a letter[10] to the Federal government advising against a new investment tax credit for CCUS.

This letter claimed that "*over 80% of CCUS projects in the United States have failed"* citing a report[11] by the Deep Decarbonization Initiative at the University of California, San Diego. In fact, this report was

[3] McCulloch, S., 2021. *Carbon Capture in 2021: Off and running or another false start.* IEA, Paris, France.

[4] https://www.cbc.ca/news/business/quest-ccs-milestone-carbon-capture-1.5645077 The facility is an SMR+CC unit.

[5] IPCC, I., 2014. Fifth Assessment Synthesis Report. *Climate Change*, pp.1-15. Intergovernmental Panel on Climate Climate Change, WMO, Geneva, Switzerland.

[6] IPCC 2014 AR5, Working Group III, Figure 6.24.

[7] Haszeldine, S. and Singh Ghaleigh, N., 2018. *Geological Factors for Legislation.* In *Carbon Capture and Storage: Emerging Legal and Regulatory Issues, 2nd Edition.* Edited by Ian Havercroft, Richard Macrory and Richard Stewart, Hart Publishing Plc., Oxford, UK.

[8] United Nations Environment Programme (2022). Emissions Gap Report 2022: *The Closing Window — Climate crisis calls for rapid transformation of societies* — Executive Summary. Nairobi. https://www.unep.org/emissions-gap-report-2022.

[9] Gross, S., ibid, see Footnote 1.

[10] Letter from scientists, academics, and energy system modellers: Prevent proposed CCUS investment tax credit from becoming a fossil fuel subsidy. Addressed to Chrystia Freeland, Deputy Prime Minister & Minister of Finance, January 19, 2022. https://pipelineonline.ca/heres-the-entire-letter-signed-by-400-academics-in-opposition-to-carbon-capture-utilization-and-storage/#/?playlistId=0&videoId=0

[11] Abdulla, A., Hanna, R., Schell, K.R., Babacan, O. and Victor, D.G., 2021. Explaining successful and failed investments in US carbon capture and storage using empirical and expert assessments. *Environmental Research Letters*, *16*(1), p.014036.

quite clear in its conclusion that "*most (>70%) proposed gas processing projects – the most mature carbon capture application – have succeeded and are in operation today. By contrast, in the power sector, close to 90% of proposed CCS capacity was never built.*" These consequences – the failure of proposed power projects but not of operating CCS facilities – were explained, by three principal factors: the importance of (i) capital cost; (ii) technological readiness; and (iii) the credibility of project revenues.[12] Furthermore, this report stressed the "*groundwork*" that CCS requires of the project development team:

1. Characterizing storage site geology.
2. Securing access to pore space.
3. Constructing pipelines or linking capture facilities with the existing CO_2 pipeline network.
4. Complying with regulatory requirements embodied in measurement, monitoring and verification regimes.

Two Canadian CCS projects, each designed for the utilization or geological storage of 1 MT CO_2 annually, have clearly succeeded in accelerating technology readiness and are widely cited as examples of what is required for success. Geological issues associated with these CCS projects are discussed in section 5 of this Road Map.

The first is the Boundary Dam 3 (BD3[13]) project in southern Saskatchewan. Most of the captured CO_2 from the coal-powered electricity generation at BD3 is directed to enhanced oil recovery (EOR) in the Weyburn-Midale oil field, however a fraction (~10%) is diverted on occasion to the Aquistore[14] project, which is one of dedicated geological storage, i.e., the CO_2 is stored not utilized. BD3 suffered from technical problems in 2021 associated with its compressors[15], which, as a first-of-a-kind facility worldwide, is hardly unusual[16]. SaskPower's BD3 generating station has captured over 4.5 million tonnes of CO_2 since 2014, with 89% of the CO_2 from the flue sent to the capture plant.

The second is Quest[17],[18] in Alberta. Quest captures CO_2 from the hydrogen manufacturing unit, a steam methane reformer (SMR), at the Shell Scotford bitumen upgrader near Edmonton using Athabasca oil-sands as the bitumen feedstock and natural gas feedstock in the SMR. The CO_2 effluent is 99% pure[19] and is transported to injection wells by an 80 km CO_2 pipeline, where it is injected into the Basal Cambrian Sandstone at 2 km depth. The Quest project has captured more than six million tonnes since 2015.

Both BD3 and Quest received very strong government support and financing at a time before investment tax credits (ITCs) were available. Shell Canada, the operator of Quest, had anticipated and benefitted

[12] Abdulla et al., 2021, ibid.
[13] Preston, C., Bruce, C. and Monea, M., 2018, October. An Update on the Integrated CCS Project at SaskPower's Boundary Dam Power Station. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).
[14] Worth, K., White, D., Chalaturnyk, R., Sorensen, J., Hawkes, C., Rostron, B., Risk, D., Young, A. and Sacuta, N., 2017. Aquistore: Year One–Injection, Data, Results. *Energy Procedia*, 114, pp.5624-5635.
[15] https://www.eenews.net/articles/ccs-red-flag-worlds-sole-coal-project-hits-snag/, accessed 2022-11-30.
[16] Herzog, H.J., 2018. *Carbon capture*. MIT Press.
[17] Preston, C., 2018, October. IEAGHG Summary Report of the Shell Quest Carbon Capture and Storage Project. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).
[18] Rock, L., O'Brien, S., Tessarolo, S., Duer, J., Bacci, V.O., Hirst, B., Randell, D., Helmy, M., Blackmore, J., Duong, C. and Halladay, A., 2017. The Quest CCS project: 1st year review post start of injection. *Energy Procedia*, 114, pp.5320-5328.
[19] Personal communication, Dave Schnepper, Shell Canada, June 4, 2022.

from the 2008 Government of Alberta announcement establishing a $1.24 billion CCS Fund, which provided it with $745 million over 15 years in addition to C$120 million for the Federal government's Clean Energy Fund. BD3 required Federal funding to offset the cost of developing this first-of-a-kind project that was anticipated to have technology risks and associated costs. During the 3rd Quarter of 2022, the BD3 CCS facility was available 94.5% of the time, capturing 219,750 tonnes of CO_2. Given the design capacity of 90% CO_2 capture, this is ~85% capture. The total cost to retrofit the generating station's power unit and build the carbon capture unit was $1.5 billion[20], of which the Federal Government contributed $240 million with the balance from SaskPower based on projected revenue from sales of CO_2 for enhanced oil recovery (EOR) at the nearby Weyburn-Midale oilfield.

The government contributions to both Quest and BD3 allowed these projects to become commercially viable and have allowed critical lessons to be learned in developing subsequent CCS projects. Critically, Alberta also established clear and attractive legislation in 2010 by amending the Mines and Minerals Act through the Carbon Capture and Storage Statutes Amendments Act of 2010. This addressed "*the questions of long-term liability for CO_2 stored underground, pore space access and ownership, and the funding of maintenance and remediation following closure*"[21]. Bankes[22] stated that this was a "*clean and bold ownership solution*" in that it established a regulatory framework by (i) declaring that the pore space in Alberta's subsurface belongs to the provincial Crown (except where it belongs to Canada) and (ii) establishing a tenure system for geological CO_2 storage based on a renewable permit for a 5-year term, if accompanied by a plan for measurement, monitoring and verification (MMV) of the proposed storage operations.

In Ontario, the provincial government has only recently become interested in the issue again after having investigated CCS in 2007-8. At that time, Ontario's Ministry of Natural Resources[23] released a review and analysis of the potential for geological CO_2 storage in Ontario including a 5-year study that would "*focus on deep formations beneath and adjacent to Lake Erie and Lake Huron,*" which had been identified by Shafeen at the University of Waterloo[24] as having good storage potential.

Subsequently, Hewitt[25] outlined the opportunities for geological CO_2 storage in Ontario, provided explicit guidance as to how sites might be characterized and noted the legal uncertainties, many of which exist to this day. Nothing has come of this earlier plan. The provincial government lost interest in CCS as it terminated the operations of Ontario Power Generation's coal-powered electricity generating stations,

[20] Preston et al., (2018, footnote 12).

[21] Krupa, H.J., 2018, The legal framework for carbon capture and storage in Canada. In: Havercroft, I., QC, Macrory, R. Hon QC and Stewart, R. eds., 2018. Carbon Capture and Storage: emerging legal and regulatory issues. Bloomsbury Publishing, Oxford, UK.

[22] Bankes, N., 2022, *The Legal and Regulatory Framework for Carbon Storage Projects in Alberta.* Workshop Presentation at: Geological CO2 Storage in Ontario: Addressing the Regulatory Uncertainties. Balsillie School of International Affairs and Waterloo Institute for Sustainable Energy, Waterloo, Ontario, 13 October 2022.

[23] Carter, T., Gunter, W., Lazorek, M. and Craig, R., 2007. *Geological sequestration of carbon dioxide: a technology review and analysis of opportunities in Ontario*. Climate Change Research Report-Ontario Forest Research Institute, (CCRR-07), Ministry of Natural Resources, Sault Ste. Marie, Ontario.

[24] Shafeen, A., Croiset, E., Douglas, P.L. and Chatzis, I., 2004. CO_2 sequestration in Ontario, Canada. Part I: storage evaluation of potential reservoirs. *Energy Conversion and Management*, 45(17), pp.2645-2659.

[25] Hewitt, A.E., 2008, *New Commercial-Scale Underground Storage Opportunities in Ontario*, Presentation at the 47th Annual Ontario Petroleum Institute (OPI) Conference, Niagara Falls, Ontario.

including the Nanticoke GS that was emitting over 15 M tonnes of CO_2 annually in the period 2005-2008.

In November 2022, the Ontario government proposed legislative change to the prohibition on the geological injection and storage of CO_2 into the subsurface that was contained in the Oil, Gas and Salt Resources Act and on the utilization of CO_2 in EOR operations. It indicated further regulatory actions would be forthcoming in 2023 including issues arising from pilot projects and the development of CCS hubs. This announcement shortly followed a workshop on the regulatory uncertainties existing in Ontario. The summary report of this workshop is attached as Appendix C.

Nevertheless, industry in Ontario is disadvantaged in adopting CCS because of the competition for capital needed to build CCS plants (typically an amine-absorption unit costs ~$1 billion depending on size). The Federal 2022 budget provided an investment tax credit (ITC) for pipelines and "injection and storage equipment" of 37.5%, lasting until 2030; capture costs are eligible for a 60% ITC until 2030. No ITC is available in Ontario for dedicated geological storage of CO_2 under the 2023 Federal budget[26].

A recent analysis[27] of this financing issue indicated that the ITC available from the Canadian government likely covers less than 25% of total projected capital and operating costs (CAPEX + OPEX) for CCS facilities that conceivably will be operating in 2030 as compared with nearly ⅔ of total costs for facilities in the U.S. qualifying for CCS grants under the 2022 Inflation Reduction Act.

Consequently, there is concern in Ontario's industries that, without further federal or provincial support, total projected costs for CCS operations in Ontario will result in uneconomic industrial operations in Ontario leading to plant closures and replacement of Ontario production with US production made attractive by the more generous US ITCs.

1.2 Objectives

In 2006 CanmetENERGY published a Road Map for CCS in Canada, with an emphasis on western Canada, known as CCSTRM[28]. It noted that geological CO_2 storage was important to Canada and anticipated the rapid development of CCS in western Canada since 2006, e.g., Quest and BD3. In 2006, capture technologies were not considered mature and, in hindsight, the understanding of the accessible geological storage capacity and the behaviour of injected CO_2 in the subsurface was primitive. It strongly urged the use of demonstrations to ensure that newly developed CCS technologies work well under Canadian conditions. CCSTRM concluded that there was an important need for the "*national coordination of R&D and demonstration efforts undertaken on CCS.*"

This important need has not changed, and this Road Map seeks to identify the research, development, and demonstration (RD&D) needs that have emerged in the years since the publication of CCSTRM in 2006 more clearly. Here we analyze future needs and identify objectives through 2030 with specific

[26] https://www.budget.canada.ca/2023/report-rapport/chap3-en.html#a5: only BC, Alberta and Saskatchewan are included.
[27] BMO Capital Markets, August 22, 2022, *Canada Falling Behind in CCUS Policy, Following U.S. Upgrade.*
[28] *Canada's CO_2 Capture & Storage Technology Roadmap*, March 2006, Natural Resources Canada.

reference to geological CO_2 storage in Ontario, although it is anticipated that this Road Map may have quite general applicability throughout Canada given the interest in the Cambrian sandstone.

The motivation behind this Road Map is to create a decision aid allowing industry, governments, and academia to plan and prioritize resources for supporting the development of one or more carbon capture and sequestration (CCS) hubs by industry in southwestern Ontario by 2030. It provides a high-level assessment of the priority geological reservoirs for subsurface CO_2 storage. Identification of the specific geological formations in SW Ontario that warrant industrial development as CCS hubs will allow engineers and geoscientists from industry, government and universities to focus on the RD&D issues arising from such development. The Road Map will support decision making by both heavy industry and the federal and provincial governments in their work to achieve substantially reduced CO_2 emissions by 2030 and net-zero emissions by 2050.

1.3 This Road Map

A wide variety of technical, social, and economic issues associated with carbon capture and transportation must also be resolved before 2030. The inhibitors to decision-making in this context have been identified by the Global CCS Institute in a 2021 report prepared for the Government of Alberta[29], which is shown as Table 1-2.

The industrial sources that are the subject of this assessment are presented in section 2 using data publicly available from Environment Canada for 2020[30]. These are listed in terms of general industrial sectors in order of emissions in 2020. The reader interested in general reviews of decarbonization by heavy industry are referred to reviews by McKinsey & Company[31], the Brookings Institution[32] and the US Government Accountability Office[33], which have been used as sources in this Road Map.

The infrastructure required for carbon capture and transportation is reviewed in section 3. Of the three technological approaches to reducing CO_2 emissions in SW Ontario, we will briefly review two of the three important mitigation pathways in section 4: (i) reducing energy use through industrial efficiencies and (ii) shifting to low-carbon energy sources. In addition, in section 4, we consider how hydrogen (H_2) generation and storage may complement CCS in SW Ontario as a mitigation measure.

The critical tasks of geological CO_2 storage are summarized in Section 5: Evaluating and selecting CO_2 storage reservoirs in SW Ontario. The utilization of captured CO_2 in EOR is employed in Alberta and is now permitted in Ontario, therefore some deep depleted oil and gas fields are considered. More importantly, saline aquifers are under consideration for geological CO_2 storage in SW Ontario.

[29] *Addressing the Barriers to CCS Investment – Lessons from Other Countries*. Prepared for the Government of Alberta, March 2021, Global CCS Institute, Melbourne, Australia. See Table 1, page 6.
[30] Environment Canada data is from: https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/facility-reporting/data.html
[31] *Decarbonization of Industrial Sectors: The Next Frontier*. June 2018. McKinsey & Company.
[32] Gross, S., 2021, *The Challenge of Decarbonizing Heavy Industry.* Brooking Institution, Washington D.C., USA.
[33] *US Government Accountability Office, 2022. Decarbonization: Status, Challenges, and Policy Options for Carbon Capture, Utilization and Storage. Washington D.C., USA.*

Section 6 addresses the development of CCS hubs in SW Ontario that may be either 'open-access', i.e., accessible to all emitters, or private access. More importantly, it is here that the RD&D issues arise as attempts are made to undertake geological CO_2 storage in SW Ontario. Here, the Road Map becomes retrospective in style, in that it identifies the goal in year 2030 and works backwards to 2023 to establish the activities that must occur to allow geological CO_2 storage by 2030.

For the purposes of data summaries and statistics, SW Ontario is defined as the geographic area to the West of Hwy 400 and West of Hwy 427 in Toronto. The area is shown in Figure 1-1. The distribution of CO_2 emitters across southern Ontario is shown in Figure 1-2.

FIGURE 1-1 DEFINING THE GEOGRAPHICAL EXTENT OF SW ONTARIO

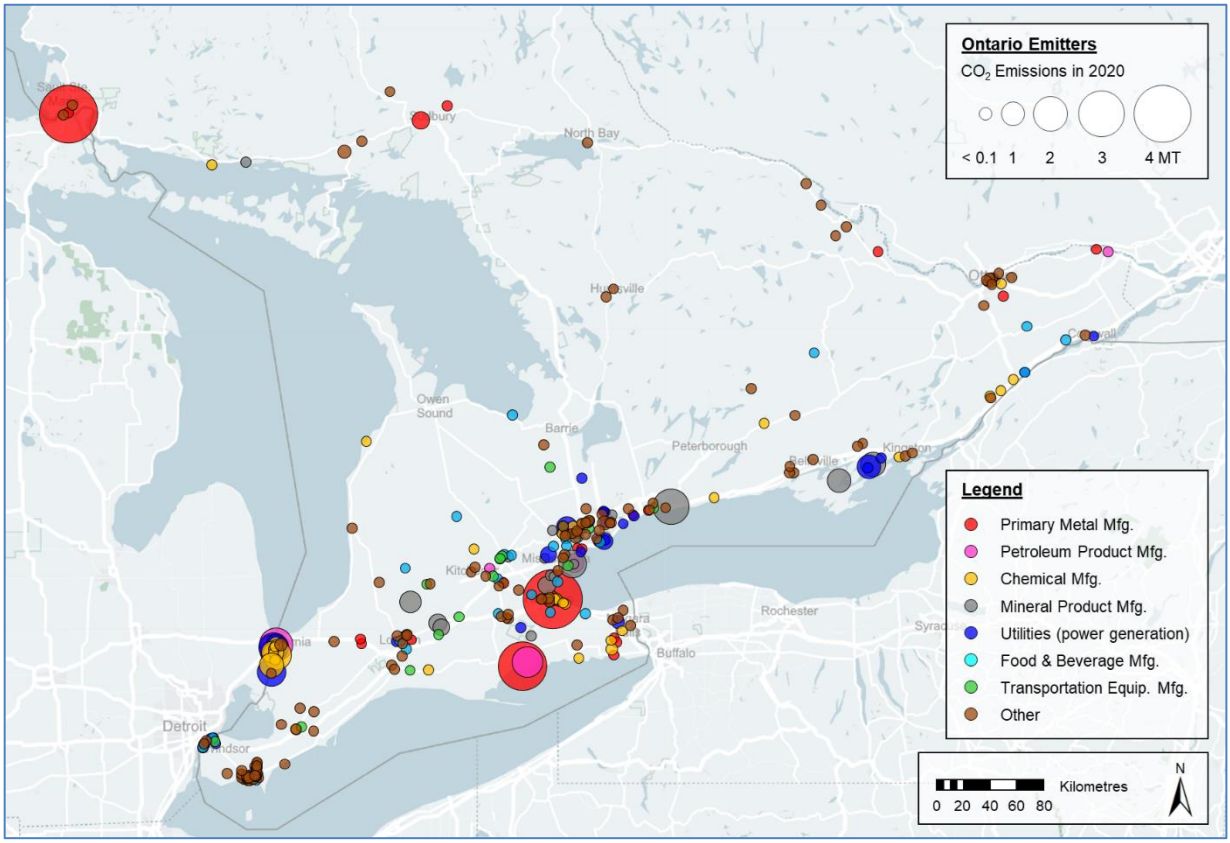

FIGURE 1-2 PRINCIPAL CO_2 EMITTERS IN SOUTHERN ONTARIO

TABLE 1-1 CO_2 EMISSIONS BY INDUSTRIAL SECTOR IN SW ONTARIO

Sector	Number of Emitters	Total CO_2 (kT)	% of Total
Manufacturing	116	19,400.1	78.3
Utilities	19	3,777.2	15.2
Greenhouse, nursery and floriculture production	42	781.8	3.2
Education and health care	14	354.8	1.4
Mining and oil and gas extraction	3	235.2	0.95
Waste management and remediation services	28	152.9	0.62
Miscellaneous	4	84.2	0.34
TOTAL	**226**	**24,786.4**	**100%**

TABLE 1-2 POTENTIAL POLICY RESPONSES TO ADDRESS MAIN BARRIERS TO CCS DEPLOYMENT[34]

Barrier	Description	Examples of potential policy response
Insufficient value on CO_2 emissions	The value on reducing CO_2 emissions is insufficient, resulting in a mismatch between the private and social costs of emitting CO_2	Introduce a **value on CO_2 emissions reductions**, for example through a carbon tax, tax credit, emissions trading scheme, CCS obligation, emissions performance standard or through government procurement standards
	CCS adds to the costs of production and leads to a loss in competitiveness	Design any value on CO_2 emissions to **limit effects on competitiveness**, or consider introducing, for example, a **border adjustment tariff**
Interdependency of the CCS value chain	Emitters may have to take investment decisions for the capture facility before a transport and storage solution is operational	Provide **capital support to enable the development of shared T&S networks**, with a focus on integrated hubs and clusters where economies of scale can reduce unit costs and a diversified source of emissions can reduce the risk of asset stranding
	T&S providers have uncertain demand for their network ahead of taking final investment decisions	
High capital costs of CCS projects	The capital costs of building T&S infrastructure are high	
Information market failures	Storage operators are unable to take on uncapped storage liabilities	Consider **transfer of liabilities** after a period of time and a **collective industry insurance fund**
	Uncertainty around the policy framework weakens case for investment	Provide a **clear and stable** policy environment for CCS
Political risks	Local communities object to T&S in their area	**Facilitate community-level engagement** in CCS projects to improve public perception and, where possible, site projects away from areas of local opposition

[34] *Addressing the Barriers to CCS Investment – Lessons from Other Countries*. Prepared for the Government of Alberta, March 2021, Global CCS Institute, Melbourne, Australia. See Table 1, page 6.

2 REVIEW OF SOURCES OF INDUSTRIAL CO_2 EMISSIONS IN SW ONTARIO

Industrial emissions of CO_2 in Ontario are reviewed using the standard industrial (NAICS[35]) descriptors shown below. All data presented in this section are from Environment Canada[36] for the year 2020. Figure 2-1 shows graphically the CO_2 emissions in SW Ontario by industrial sector that are listed in Table 1-2 and that yield a total of 24.8 MT in 2020 according to Environment Canada. Note that emissions from residential and commercial buildings and from transportation are not accounted for in Figure 2-1. Manufacturing is a critical component of Ontario's economy and dominates the fixed-site emissions shown in the pie chart.

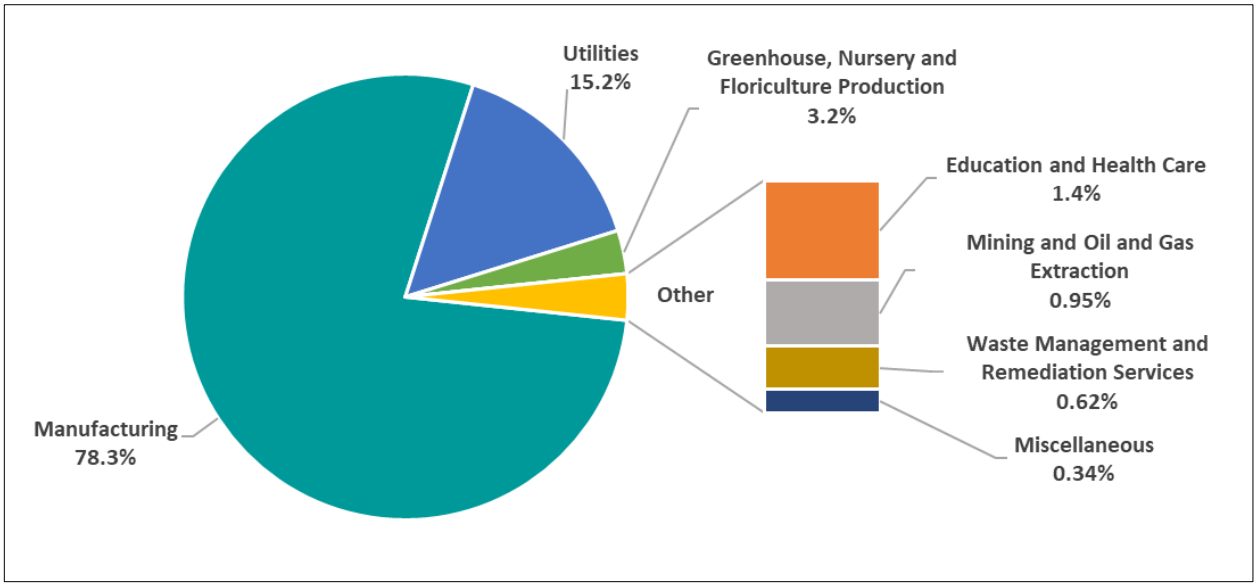

FIGURE 2-1 CO_2 EMISSIONS IN SW ONTARIO BY INDUSTRIAL SECTOR – TOTAL 24.8 MT IN 2020

The manufacturing sector contributed nearly ~20 MT of total CO_2 emissions in 2020 and can be further broken down into six primary sub-areas as shown in Figure 2-2. The highest emissions were from primary metal manufacturing by Ontario's steel industry and petroleum product manufacturing by the four major oil refineries located in SW Ontario.

This section will discuss the main sources of CO_2 emissions in each of the manufacturing sub-sectors shown in Figure 2-2, including each industrial sector's plans for decarbonization and potential requirements for CCS. We also include discussion of utilities, i.e., fossil-fueled power generation, which in Ontario is now based on natural gas combustion. The discussion is organized in order of emissions by each sector in 2020.

[35] North American Industry Classification System (NAICS) https://www23.statcan.gc.ca/imdb/p3VD.pl?Function=getVD&TVD=1181553

[36] https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/facility-reporting/data.html

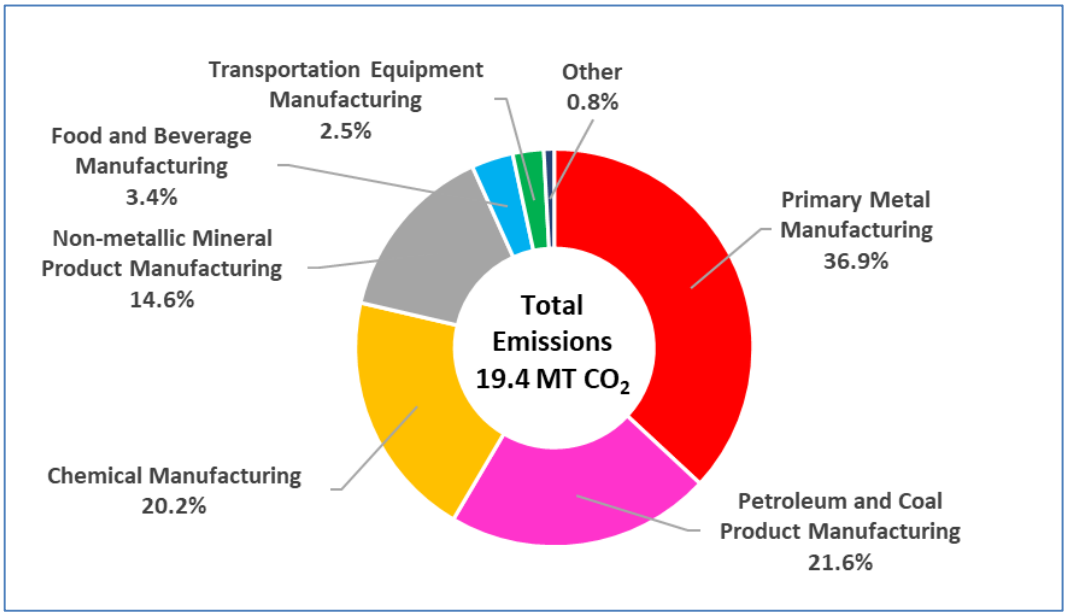

FIGURE 2-2 CO2 EMISSIONS IN SW ONTARIO BY MANUFACTURING SUB-SECTOR – TOTAL 19.4 MT IN 2020

The capture of emissions from the industrial facilities in SW Ontario will be strongly influenced by the cost and availability of carbon capture technologies. The maturity of the technology – measured by its Technology Readiness Level (TRL) – will be critical to its successful adoption by industry[37]. The TRL of any carbon capture technology is constrained by the TRL of its least mature essential component.

Figure 2-3 provides examples of TRLs indicating whether they are at the conceptual level (TRL 1-2), laboratory scale (TRL 3-5), pilot scale validation (TRL 6) or at full scale (TRL7-9). To be applicable to carbon capture in SW Ontario by 2030, we are only concerned with TRL ≥6. This includes post-combustion technologies in that capture equipment can be retrofitted to existing industrial plant with long remaining lifetimes despite having low emission CO_2 partial pressures. Recent reviews of TRLs with respect to CCS technologies has been prepared by Kearns et al[38] and Hong[39].

[37] Abdulla et al., 2021, ibid.
[38] Kearns, D., Liu, H., and Consoli, C., 2021. *Technology Readiness and Costs of CCS.* Global CCS Institute.
[39] Hong, W.Y., 2022. A techno-economic review on carbon capture, utilisation, and storage systems for achieving a net-zero CO2 emissions future. *Carbon Capture Science & Technology*, p.100044.

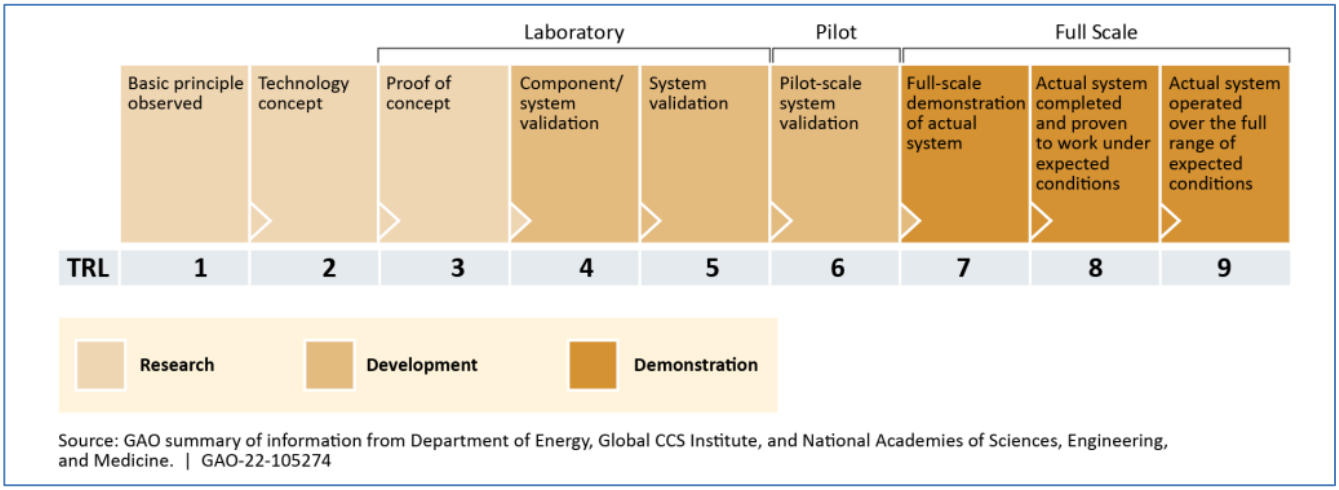

FIGURE 2-3 SCHEMATIC OF TECHNOLOGY READINESS LEVELS (GAO, 2022)

2.1 Primary Metal Manufacturing

Ontario is Canada's principal iron and steel producer. It consumes 80% of the sector's energy use across Canada[40] and produced 10 million tonnes of iron and steel in 2019[41]. Because the Ontario iron and steel sector's CO_2 emissions dominate those of the other primary metal manufacturers shown in Figure 2-3, we will concentrate on it and ignore the minor sectors such as aluminum and non-ferrous metal processing.

The steel industry is a large emitter of CO_2 because of both a carbon-rich feedstock and high-temperature heat needs. It has traditionally used coke derived from coal and must reduce iron oxide ore to iron at blast furnace temperatures of 1200°C. Steel is widely traded globally and there is a vast amount of new steel production in China some of which is sold to the North American market resulting in depressed corporate profitability when just such profitability will be required to build CCS infrastructure.

The vast majority of Canada's raw steel is produced in Ontario by three integrated manufacturers – ArcelorMittal Dofasco, Stelco and Algoma Steel, with the remainder produced by electric arc furnaces in smaller facilities ("mini-mills"). The primary metal manufacturers of SW Ontario (NAICS 331) emitted over 7.1 MT CO_2 in 2020, with their locations are located as shown in Figure 2-4, and their 2020 emissions details provided in the appendix. These three integrated manufacturers produce over 95% of total CO_2 emissions by primary metal manufacturers in Ontario and are by far the largest CO_2 emitters in the province. These facilities also emitted significant amounts of other GHG's in 2020 in SW Ontario, including nearly ~1.2 KT of CH_4 and 37 tonnes of N_2O.

The products are used in auto and auto-parts manufacturing, construction, pipe and wells for oil, gas and water production and for various types of machinery. For example, a typical industrial-sized wind

[40] Griffin, B., 2019. *Energy Use and CO2 Emissions in Canadian Iron and Steel and Ferro-Alloy Manufacturing Industries 1990 to 2017*. Canadian Energy & Emissions Data Centre, Simon Fraser University, Burnaby, BC.
[41] Cheminfo Services Inc., 2019. *Economic Assessment of the Integrated Steel Industry*. Markham, Ontario

turbine will incorporate about 140 tonnes of steel as well as 3-4 tonnes of copper and 1-2 tonnes of rare earth permanent magnets[42].

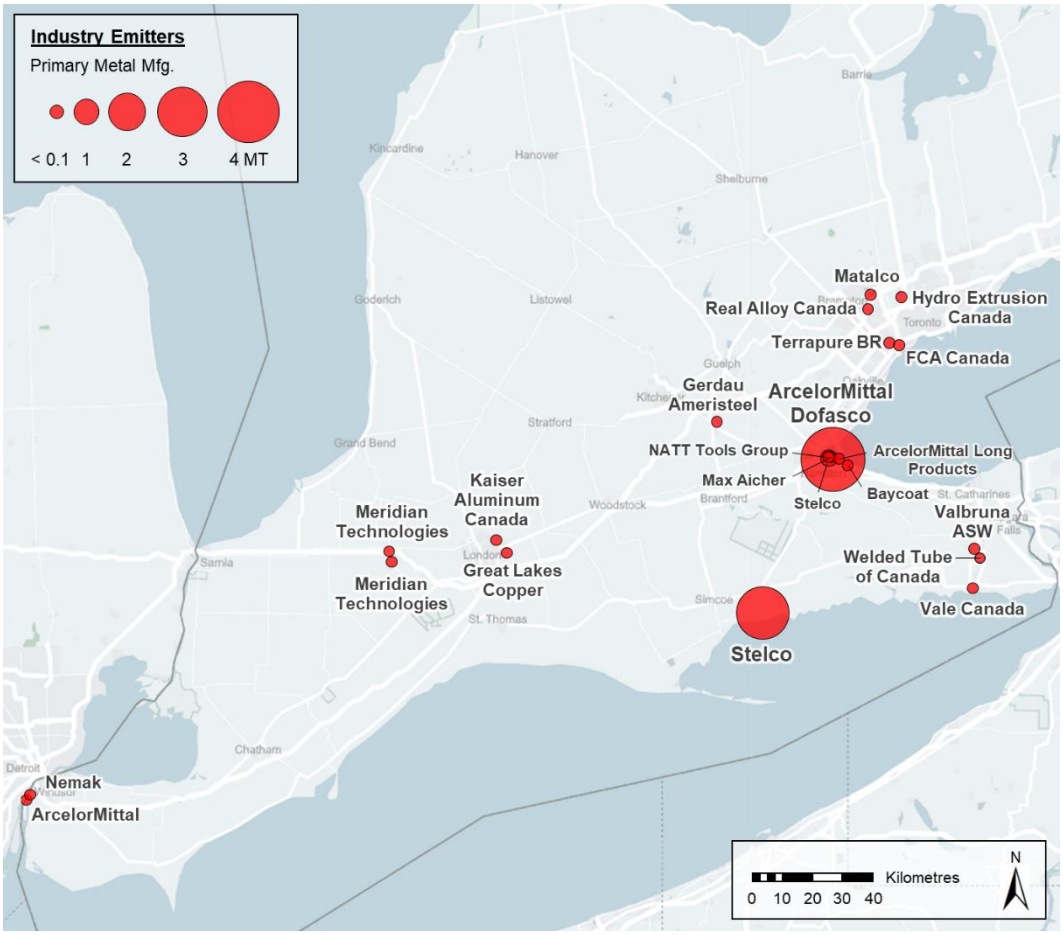

FIGURE 2-4 LOCATION OF PRIMARY METAL MANUFACTURERS (NAICS 331)

Steel is produced industrially by the three processes shown in Figure 2-5: (i) a blast furnace (BF) that produces “pig iron” from iron ore and coke produced from coal and which iron in turn is converted to ‘primary’ steel in a basic oxygen furnace (BOF); (ii) direct reduction of iron ore (DRI) by syngas (a mixture of H_2, CO and CO_2) in a shaft furnace followed by steel production in an electric arc furnace (EAF); and (iii) using steel scrap in an EAF. At present, all three integrated Ontario plants use the BF-BOF process, while three smaller facilities in Ontario use scrap metal and EAFs.

[42] The steel tonnage is from a presentation by Bilal Sheikh, ArcelorMittal Dofasco, at the Hard to Abate Club workshop, University of Waterloo, November 2022, citing data from CRU, an international commodities business consultancy. The sources of the other values are: (i) copper https://www.copper.org/resources/market_data/infographics/copper-and-the-clean-energy-transition-brochure.pdf; (ii) rare earths: https://lynasrareearths.com/products/how-are-rare-earths-used/wind-turbines/.

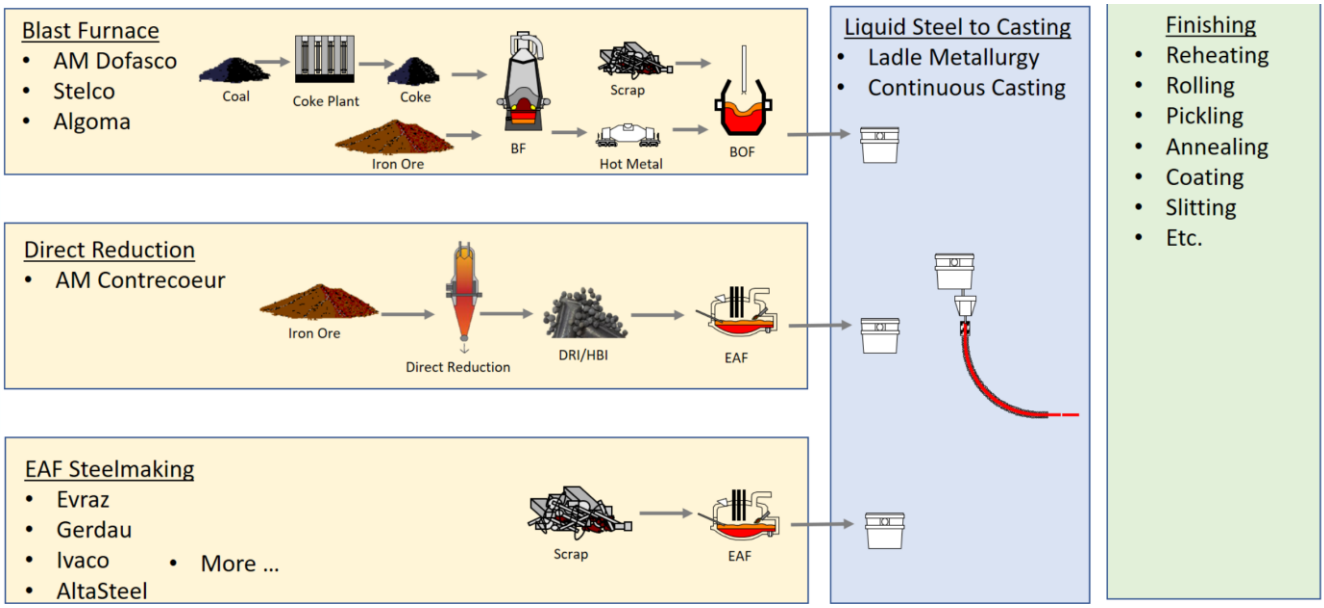

FIGURE 2-5 THE TECHNOLOGICAL VARIABILITY OF THE CANADIAN STEEL INDUSTRY

The three integrated manufacturers are decarbonizing in quite different ways:

Stelco is investigating the use of CCS at its Lake Erie Works near Nanticoke but has announced no federal or provincial funding agreements. This plant emitted 2.7 MT of CO_2 in 2020, with lesser amounts emitted at the Hamilton works (268,000 tonnes, i.e., 268 kT), which uses steel produced at the Lake Erie Works and coke during reheating and finishing. Stelco does not intend to produce steel by EAF because of concerns about the quality of such product on account of the effect of the inclusion of scrap-based impurities – e.g., Cu, N, P – which are known as 'tramp' species. Therefore, geological storage for ~ 3 MT CO_2 is expected to be part of Stelco's future[43].

ArcelorMittal Dofasco has announced[44] a $1.8 billion plan to decarbonize its Hamilton operations involving replacing its coal-fed coke ovens and blast furnaces with DRI and EAFs, which should eliminate about 3 MT of CO_2 emissions annually. At the heart of the plan is a 2.5 million tonne capacity DRI facility and an EAF facility capable of producing 2.4 million tonnes of steel. The Government of Canada announced it will invest CAD$400 million in the project and the Government of Ontario announced it will invest CAD$500 million in the project. Moving forward, strategies including alternative reductants such as hydrogen, bioenergy and biocarbon for the EAFs, and carbon management through carbon capture utilization and sequestration are being investigated to address the roughly 2MT/yr of remaining CO_2 emissions.

Algoma Steel in Sault Ste. Marie, which is outside the study area of SW Ontario, is to receive up to $420 million in federal funding to retrofit their operations and phase out coal-fired steelmaking and thus reduce CO_2 emissions by 70% or about 3 MT of CO_2. Steel production will turn to scrap based EAFs that will allow carbon injection in the form of coal powder initially and later charcoal.

[43] P. Badgley, Stelco, personal communication.
[44] ArcelorMittal Dofasco press release, 30 July 2021.

Algoma expects to have electric power delivered to the site by 2030 via a 5-km transmission line. Their smaller furnaces will rely on syngas as the reductant. Algoma Steel has no stated need for geological CO_2 storage.

Therefore, both ArcelorMittal Dofasco and Stelco have plans that will likely involve carbon capture and geological storage (CCS) of a total of 5-6 MT CO_2 annually, preferably nearby in SW Ontario.

At present, the only steel plant in the world using CCS is the DRI facility at Emirates Steel in Abu Dhabi, which can capture 800 kT CO_2 annually. Because its DRI emits a 90% CO_2 waste stream, only compression to supercritical state and dehydration is needed prior to transmission through a 50-km pipeline prior to injection in an onshore oil field for enhanced oil recovery (EOR)[45].

The flue gas emissions from steel making in Ontario are not currently anywhere near the purity of the Abu Dhabi mill, although ArcelorMittal Dofasco expects that its future DRI plant will produce pipeline grade CO_2 as a waste stream when natural gas is initially used, prior to its replacement with hydrogen. Currently in typical integrated steel plants that use the BF+BOF process, while significant absolute volumes of CO_2 are emitted, the relative fraction of CO_2 is lower and is generally no more than 22% in the case of a blast furnace.[46]. Currently, in typical integrated steel plants that use the BF+BOF process, the overall gaseous emissions contain ~15% CO_2 with the largest fraction emitted by the BF[47]. At Stelco's Lake Erie Works, BF emissions are 22-24% CO_2[48].

This low partial pressure of CO_2 indicates that any capture process used will have considerable operational expenses in capturing CO_2 from the flues: "*all else being equal, CO_2 capture costs are inversely proportional to the partial pressure in the gas stream*"[49]. Assuming that the steel industry adopts mature amine absorption capture technology on site, which is at TRL 9, the costs of capture are of the order of US$40-130 per tonne of CO_2 depending on the number of flues associated with each mill. As of September 2022, amine absorption capture has only been deployed in the iron-making operations, e.g., DRI in Abu Dhabi, and not with steel making operations such as EAF and BOF plants[50].

2.2 Petroleum & Coal Product Manufacturing

For Ontario's industries, NAICS descriptor 324 applies to the four major oil refineries, a lubricants facility, a solvent and waste oil recycling plant and a natural gas liquids fractionation and storage facility. Their total CO_2 emissions were ~4.2 MT in 2020, the vast majority of which was emitted by the four oil refineries shown in Figure 2-6. These facilities were also responsible for significant emissions of other GHG's in 2020, including 953 kT CH_4 and 50 T of N_2O. Shell's Sarnia refinery also emitted small amounts of various hydrofluorocarbons in 2020.

[45] *Carbon Capture and Storage (CCS),* World Steel Association Fact Sheet, July 2021.
[46] B.J. Jamieson, ArcelorMittal Dofasco, personal communication, 2203-01-02.
[47] Rackley, S.A., 2017. *Carbon Capture and Storage*, 2nd edn. Butterworth-Heinemann, Boston.
[48] P. Badgley, Stelco, personal communication.
[49] Kearns, D., Liu, H. and Consoli, C., 2021. *Technology Readiness and Costs of CCS.* Global CCS Institute
[50] US Government Accountability Office, 2022. *Decarbonization: Status, Challenges, and Policy Options for Carbon Capture, Utilization and Storage.* Washington D.C., USA.

FIGURE 2-6 DISTRIBUTION OF PETROLEUM & LUBRICANTS REFINING FACILITIES (NAICS 324)

An assessment of several Shell oil refineries published in 2009[51] identified the origin of CO_2 emissions within an oil refinery. The Shell studied developed a consensus that is based upon the energy consumption and associated CO_2 emissions within a typical European or US refinery, which we assume is representative of the four refineries operating in SW Ontario: (i) the largest share of emissions (~63%) is associated with stationary combustion units, such as a central heating and power plant and from process heaters, furnaces and boilers, which produce the heat for unit processes from natural or refinery fuel gas; (ii) the next largest share is process emissions, particularly from fluid catalytic cracking (~22%) and steam methane reforming for hydrogen production (~9%). The percentages cited in this section are from Byrum et al. [52]

[51] Van Straelen, J., Geuzebroek, F., Goodchild, N., Protopapas, G. and Mahony, L., 2010. CO2 capture for refineries, a practical approach. *International Journal of Greenhouse Gas Control*, *4*(2), pp.316-320.
[52] Byrum, Z., Pilorgé, H. and Wilcox, J., 2021. *Technological Pathways for Decarbonizing Petroleum Refining.* Working Paper. World Resources Institute. Washington D.C.

The general findings identified by Shell have been endorsed by others[53,54] and suggest that combustion units for heat generation will require either electrification of mechanical equipment or a switch from natural gas to hydrogen. Small combustion sources are likely to be widespread across a refinery and each emit a low CO_2 concentration (~8%), however their total emissions are large (see Sunny et al.). The Shell study indicated that the costs for their capture will be very high.

The process emissions are more readily captured in that the main sources – fluid catalytic crackers and steam methane reformers – can be retrofitted to allow carbon capture from their flues. Therefore, the percentage of CO_2 emissions within an oil refinery that it may be economically attractive to use CCS is perhaps as low as 30%. This assumes that electrification and fuel switching were able to eliminate the balance of the present emissions from stationary combustion sources by 2030.

The implication of this is that, based on Environment Canada's 2020 CO_2 emissions from the three Sarnia area refineries[55], only 30% of the total 2.7 MT may require geological storage. The total amount of current emissions from the Sarnia-Lambton area that might need geological storage has to include not only these refinery emissions but also the capturable emissions from the 30+ petrochemical, fertilizer and natural-gas fired power plants in the Sarnia-Lambton area. However, it is uncertain what the additional tonnage of CO_2 generated by fuel switching to blue hydrogen will be; this additional CO_2 will require geological CO_2 storage for the hydrogen to be counted as 'blue'.

2.3 Chemical Manufacturing

Ontario's chemical manufacturing companies (NAICS 325) produce petrochemicals, fertilizer and other inorganic chemicals, resins, plastics, and various speciality chemicals. In 2020, it emitted 3.9 MT CO_2 (see Table 325 in Appendix A). In terms of GHG's other than CO_2, the chemical manufacturing industry emitted nearly ~400 T CH_4 and ~73 T N_2O in 2020. Around 75% of these emissions were from three main sources: NOVA Chemicals site in Corunna, Imperial Oil's chemical plant in Sarnia, and CF Industries nitrogen fertilizer complex in Courtright, Ontario.

As the previous discussion indicates, the location of the largest emissions is the Sarnia-Lambton petrochemical cluster, where there is considerable integration between chemical plants, refineries, and industrial gas producers. This is also a liability in that the refineries anchor the manufacturing base of the Sarnia-Lambton petrochemical cluster and, should one close, the viability of other plants would be jeopardized. Figure 2-7 illustrates the distribution of chemical manufacturing facilities.

In 2021, IHS Markit[56] undertook a competitiveness survey of the Sarnia-Lambton industry and identified the area as among the least competitive petrochemical manufacturing areas in North America. Therefore, IHS concluded, it is disadvantaged among petrochemical manufacturing areas in North

[53] Madugula, A.C.S., Sachde, D., Hovorka, S.D., Meckel, T.A. and Benson, T.J., 2021. Estimation of CO_2 emissions from petroleum refineries based on the total operable capacity for carbon capture applications. *Chemical Engineering Journal Advances*, 8, p.100162.
[54] Sunny, N., Bernardi, A., Danaci, D., Bui, M., Gonzalez-Garay, A. and Chachuat, B. 2022 A pathway towards net-zero emissions in oil refineries. *Frontiers in Chemical Engineering*,4:804163.
[55] See Table Axx in the Appendix.
[56] IHS Markit, 2021, Ontario Petrochemical Industry Study.

America in which to invest the capital expenditures. For reasons outlined earlier, this disadvantage must also apply to CAPEX for decarbonization.

This is perhaps emphasized by the lack of recent investment in the area; the notable exception is the Nova Chemical expansion of its ethylene and polyethylene resin plants. However, IHS concluded that "*from the emissions standpoint, Sarnia plants are reasonable and generally within the expected ranges of North America chemical facilities."*

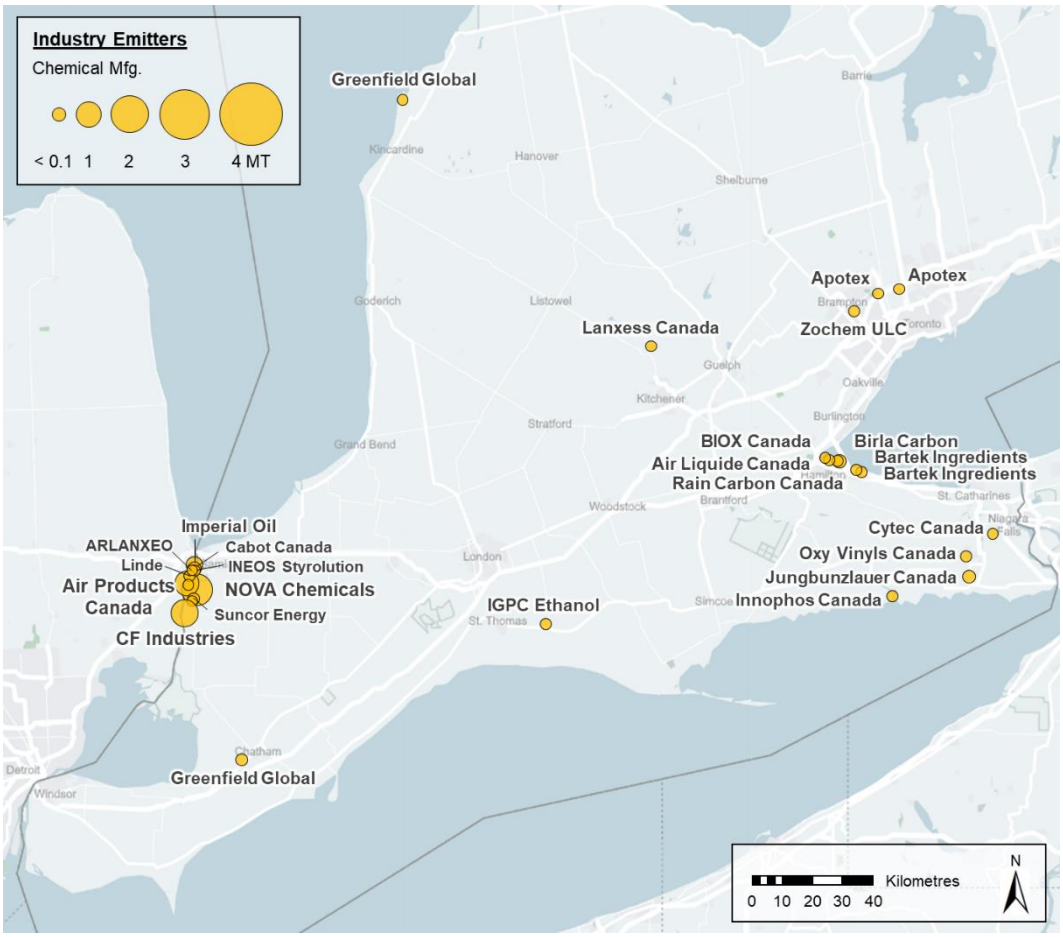

FIGURE 2-7 CHEMICAL MANUFACTURING FACILITIES (NAICS 325)

Decarbonization of the chemical industrial sector is anticipated to occur through feedstock and fuel switching, e.g., natural gas to hydrogen, plant modernization and associated efficiency improvements, and low-carbon technologies, including CCS[57,58]. Therefore, significant CO_2 volumes for CCS may only be possible where the flues of large unit processes can be retrofitted to capture the emitted gas. This might include steam methane reformers in nitrogenous fertilizer production and steam cracking in

[57] Fusco, D., 2022. *The Ontario Chemical Industry: Renewal and Transformation.* Presentation to the Hard to Abate Club, University of Waterloo, 4 November on behalf of the Chemistry Industry Association of Canada.
[58] Levi, P.G. and Cullen, J.M., 2018. Mapping global flows of chemicals: from fossil fuel feedstocks to chemical products. *Environmental Science & Technology*, *52*(4), pp.1725-1734.

ethylene production[59]. Consequently, it is possible that the volumes of CO_2 generated in the Sarnia-Lambton area requiring CCS may be similar (~30%) to that considered above for oil refining. An additional uncertainty arises in estimating the additional tonnage of CO_2 generated by fuel switching to blue hydrogen, which will require geological CO_2 storage for the hydrogen to be counted as 'blue'.

Ironically, with respect to CCS, the IHS study indicated that Sarnia-Lambton had "*access to ample underground salt caverns for CO_2 sequestration*". This is misleading in that the salt caverns in question are too shallow and volumetrically too small for geological CO_2 storage and are better suited to and should be reserved for hydrogen storage.

2.4 Non-Metallic Mineral Product Manufacturing

This industry sector (NAICS code 327) includes the manufacturing of cement and lime, as well as other non-metallic mineral-based goods, such as bricks, glass containers, glass fiber materials, and gypsum products (e.g., drywall). The locations of these industrial emitters are shown in Figure 2-8, with details found in Appendix A.

FIGURE 2-8 NON-METALLIC MINERAL PRODUCT MANUFACTURING EMITTERS (NAICS 327)

Of the total CO_2 emissions of ~2.8 MT in 2020 for this sector, the vast majority (~2.5 MT or around 87%) was emitted from cement and lime manufacturing. Therefore, this section will focus on these two

[59] Gross, S., 2021, *The Challenge of Decarbonizing Heavy Industry.* Brooking Institution, Washington D.C., USA.

primary sources, which includes three cement manufacturers (CRH Ash Grove, St. Marys Cement and Federal White Cement), and one lime producer (Carmeuse) with two different operations in SW Ontario. The CRH Ash Grove cement plant in Mississauga was the largest emitter in this sector in 2020 not only in terms of CO_2 (0.9 MT), but also with respect to the other greenhouse gases: CH_4 (125 tonnes) and N_2O (6.6 tonnes).

Importantly, there are also three other large cement industry emitters east of Toronto, along Lake Ontario, namely, St. Marys Cement in Bowmanville (1.5 MT of CO_2 in 2020), Lafarge in Bath (0.7 MT of CO_2 in 2020) and Lehigh Hanson Materials in Picton (0.6 MT of CO_2 in 2020), as well as Carmeuse's smaller lime plant in Blind River in northern Ontario (0.1 MT of CO_2 in 2020). These emitters are outside the study area of SW Ontario and remote from suitable geological storage sites.

The cement sector is the third-largest industrial energy consumer in the world, with cement production accounting for approximately 7 % of global CO_2 emissions[60]. In Canada, the cement industry contributes $76 billion annually to the Canadian economy and is responsible for approximately 158,000 direct and indirect jobs across the country[61]. In 2019, cement manufacturing accounted for a total of 1.5 % of Canada's GHG emissions[62].

The main challenge for the cement and lime producers is that the CO_2 is generated inherently as part of the manufacturing process. Approximately 60% of the overall emissions are process related, resulting from the calcination reaction of limestone ($CaCO_3$) in a high temperature kiln into CaO (lime) and CO_2. This calcining reaction produces a flue gas with CO_2 concentrations in the range of 14-33%[63]. The remaining 40% of emissions originate from burning fossil fuels to generate the required high temperatures, which can be managed through fuel switching and efficiency gains. However, the process emissions are difficult to mitigate without CCUS.

Examples of the plans and initiatives for decarbonization of the cement and lime industries are provided in the following references, both globally and in the Canadian context[64]. The primary strategies involve increasing clinker substitutes (e.g., fly ash, etc.), reducing reliance on fossil fuels by switching to lower-carbon alternatives, improving energy and materials efficiency, optimizing the design of concrete projects and use of concrete during construction, and investing in technology and innovation, including CCUS.

[60] IEA, 2022. Industry Tracking Report, International Energy Agency, September 2022.

[61] ISED, 2022. Roadmap to Net-Zero Carbon Concrete by 2050: Positioning Canada's cement and concrete industry as a global leader in the production of, and technologies related to, low-carbon and concrete, Innovation, Science and Economic Development Canada, 2022.

[62] Auer, A., and Petrevan, S., 2022. Delivering decarbonisation with demand-side initiatives, *World Cement*, October 2022.

[63] Rackley, S.A., 2017. *Carbon Capture and Storage.* 2nd edn. Butterworth-Heinemann, Boston.

[64] See for example, ISED, 2022, ibid; Auer and Petrevan, 2022, ibid; GCCA, 2021. Concrete Future: The GCCA 2050 Cement and Concrete Industry Roadmap for Net Zero Concrete, Global Cement and Concrete Association, 12 October 2021.; Fennell, P., Driver, J., Bataille, C., and Davis, S.J., 2022. Going net zero for cement and steel, Nature, Vol. 603, pp. 574-577, 24 March 2022.; Czigler, T., Reiter, S., Shulze, P, and Somers, K., 2020. Laying the foundation for zero-carbon cement, McKinsey & Company, 2020.; IEA, 2018. Technology Roadmap: Low-Carbon Transition in the Cement Industry, International Energy Agency, March 2018.; Simoni, M., Wilkes, M.D., Brown, S., Provis, J.L., and Kinoshita, H., 2022. Decarbonising the lime industry: State-of-the-art, Renewable and Sustainable Energy Reviews, Vol. 168, October 2022, 112765.

In addition to these technical aspects, the industry is advocating for policies associated with low-carbon or "green" procurement, the creation of performance bases standards and regulations, and targeted market-price assurance[65]. A business case for decarbonization involving costly technologies, such as carbon capture, requires a high measure of certainty that there will be a buyer and sufficient market value for the higher priced lower-carbon products in the future[66].

Regardless of the challenges, CCUS is an essential and necessary component for this hard-to-abate sector if it is going to reach net zero emissions by 2050. There are currently no commercial CCS facilities in operation in the cement and lime industries, however, Heidelberg Cement is in the process of constructing the world's first major CCS project attached to its Norcem cement plant in Brevik, Norway, with the goal of capturing 0.4 MT of CO_2 per year starting in 2024[67]. In Canada, Heidleberg Cement and Enbridge are collaborating on a CCS solution for Heidelbergs's cement manufacturing facility in Edmonton, Alberta, with the goal of being online by 2025 and capturing approximately 0.78 MT CO_2/yr, which will then be transported by Enbridge via pipeline and geologically stored in the Wabamun area[68].

The lime industry is pursuing full-scale CCUS projects at several facilities including Lhoist in France[69], Nordkalk in Scandinavia[70], and Carmeuse in Belgium[71]; operations are anticipated to start over the next several years.

The 2021 roadmap by the Global Cement and Concrete Association (GCCA) estimated that CCUS would account for 36% of CO_2 emission savings from cement production in the pathway to net-zero[72]. Canada's plan for achieving net-zero carbon concrete by 2050 was developed recently by the Cement Association of Canada and Innovation, Science and Economic Development Canada[73], however, the ISED Road Map lacks any indication of the possible need for geological CO_2 storage.

Based on discussions with industry representatives, it is expected that CCUS could reduce emissions by around 30 %, for a total of 0.75 MT of CO_2 per year requiring storage from this sector in SW Ontario. However, because of the uncertainties in the legal and regulatory environments regarding CCS in Ontario, as outlined in Section 1 of this report, and the long time associated with permitting, design,

[65] ISED, 2022, ibid.
[66] Auer and Petrevan, 2022, ibid.
[67] Global CCS Institute, 2022. Facilities Database (https://co2re.co/FacilityData).
[68] Heidelberg Materials, 2022 – Jan 26 2022 Press Release (https://heidelbergmaterials.us/home/news/news/2022/01/26/lehigh-cement-and-enbridge-agree-to-advance-a-co2-storage-solution-in-alberta).
[69] Air Liquide, 2022 May 09 Press Release (https://www.airliquide.com/group/press-releases-news/2022-05-09/air-liquide-and-lhoist-join-forces-launch-first-its-kind-decarbonization-project-lime-production).
[70] Nordkalk, 2022 Dec 14 Blog Post (https://www.nordkalk.com/carbon-capture-storage-and-utilisation-in-lime-manufacturing/).
[71] Carmeuse, 2020 Dec 10 News Release (https://www.carmeuse.com/eu-en/newsroom/global/carmeuse-engie-and-john-cockerill-join-forces-reduce-industrial-co2-emissions).
[72] GCCA, 2021, ibid.
[73] ISED, 2022, ibid.

construction, and commissioning of such facilities, it is likely to take many years to realize the benefits of reduced carbon emissions from this industry sector in SW Ontario.

2.5 Utilities

In 2003, coal-powered electricity generation at the Nanticoke and Lambton generating stations (GS) emitted 21.9 MT CO_2. Over the course of the next ten years, these emissions were eliminated by the closing of these and other coal-powered stations and the substitution of electricity from new generating plants fueled by natural gas and by wind- and solar-power facilities.

CO_2 emissions in 2020 from 19 utility facilities in Ontario totaled 3.8 MT. The largest fraction was due to emissions by co-generation and combined-cycle gas turbine (CCGT) plants spread across SW Ontario as shown in Figure 2-9, such as the Halton Hills Generating Station, Greenfield South Power, Goreway Power Station and TransAlta Cogen in Sarnia, which is a combined heat and power facility. The utilities also emitted nearly ~1 KT CH_4 and ~200 tonnes of N_2O in 2020.

Because of the need for hydrogen (H_2) to replace fossil fuels in various industrial plants, it is likely that additional natural gas plants may be built – or existing ones be expanded – and coupled with steam methane reformers (SMRs) to generate H_2. Therefore, CO_2 production would increase at a rate of ~11.9 tonnes CO_2 per tonne of H_2[74]. These additional CO_2 emissions will have to be captured and geologically stored if the hydrogen generated is to be considered 'blue hydrogen'.

The amount of additional CO_2 that might be emitted is speculative because the production of blue hydrogen to be commissioned is similarly speculative. If, for example, the total blue hydrogen produced in Ontario were equal to what might be expected from electrolyzer-generated or 'green' hydrogen, then about 800,000 T H_2 would be produced by 2050. This would be enough to generate 6 GW of energy[75]. Assuming the CO_2 emissions from SMRs are ~11.9 T CO_2 per T of H_2 produced, the additional CO_2 emissions from blue hydrogen generation might be of the order of 10 MT/yr by 2050 with, perhaps,1 MT/yr by 2030.

The uncertainty associated with this additional emission is large but, it should be noted, the 2050 number itself is far larger than the total 2020 emissions of 3.8 MT/yr by utilities. As will be shown in Section 5, geological storage constraints suggest it would be best to locate blue hydrogen production in an area with promising geological properties, e.g., Essex County.

[74] Eric Croiset, Professor of Chemical Engineering, University of Waterloo suggested this value as a median value of estimates. Values appearing in the literature range from 5.5 to over 13 T CO_2/T H_2.
[75] Tom Lumley, OPG, personal communication, January 2, 2023, estimated this H_2 tonnage but stressed its uncertainty.

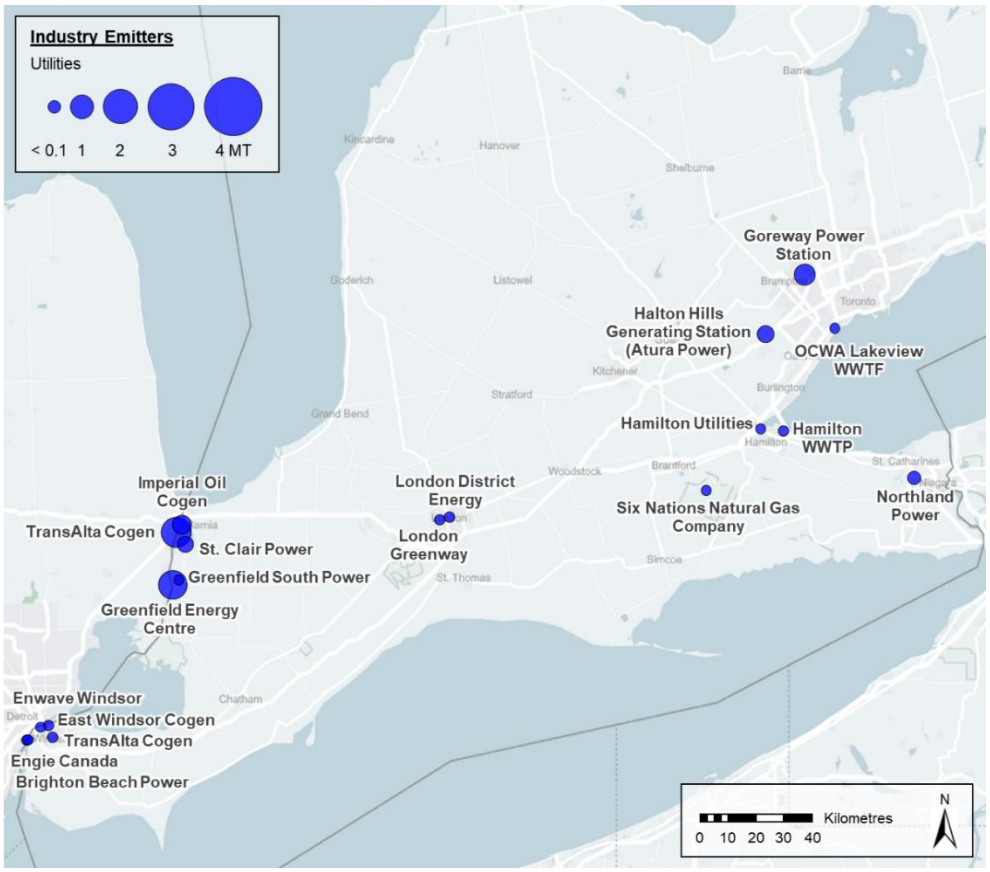

FIGURE 2-9 CO_2 EMISSIONS BY UTILITIES (NAICS 221)

In April 2022, natural gas constituted only 6% of Ontario's electricity supply and was used to generate electricity during interruptions in the supply of electricity by nuclear, wind and solar power[76]. Additional emissions of CO_2 generated from natural gas is expected between 2023 and 2030 by the Independent Electricity System Operator to replace lost nuclear power with the shut down of the Pickering Generating Station and refurbishment of the nuclear generating stations at Bruce and Darlington.

2.6 Food and Beverage Manufacturing

Food and beverage manufacturing accounted for around 3.4% of the total manufacturing sector emissions in 2020. The total CO_2 emissions were 658 KT from 21 different sources. The food industry emitters (NAICS 311) included sugar, snack food, and dairy and meat product manufacturers, as well as grain and oilseed milling and fruit and vegetable processing (e.g., canning, pickling, and drying). The emissions from two breweries and two distilleries accounted for nearly all the emissions from beverage manufacturing (NAICS 312). Figure 2-10 shows the location of the emitters for this sector, with details found in Appendix A.

[76] *Ontario's Low-Carbon Hydrogen Strategy – A Path Forward*. 2021. Government of Ontario, 56p.

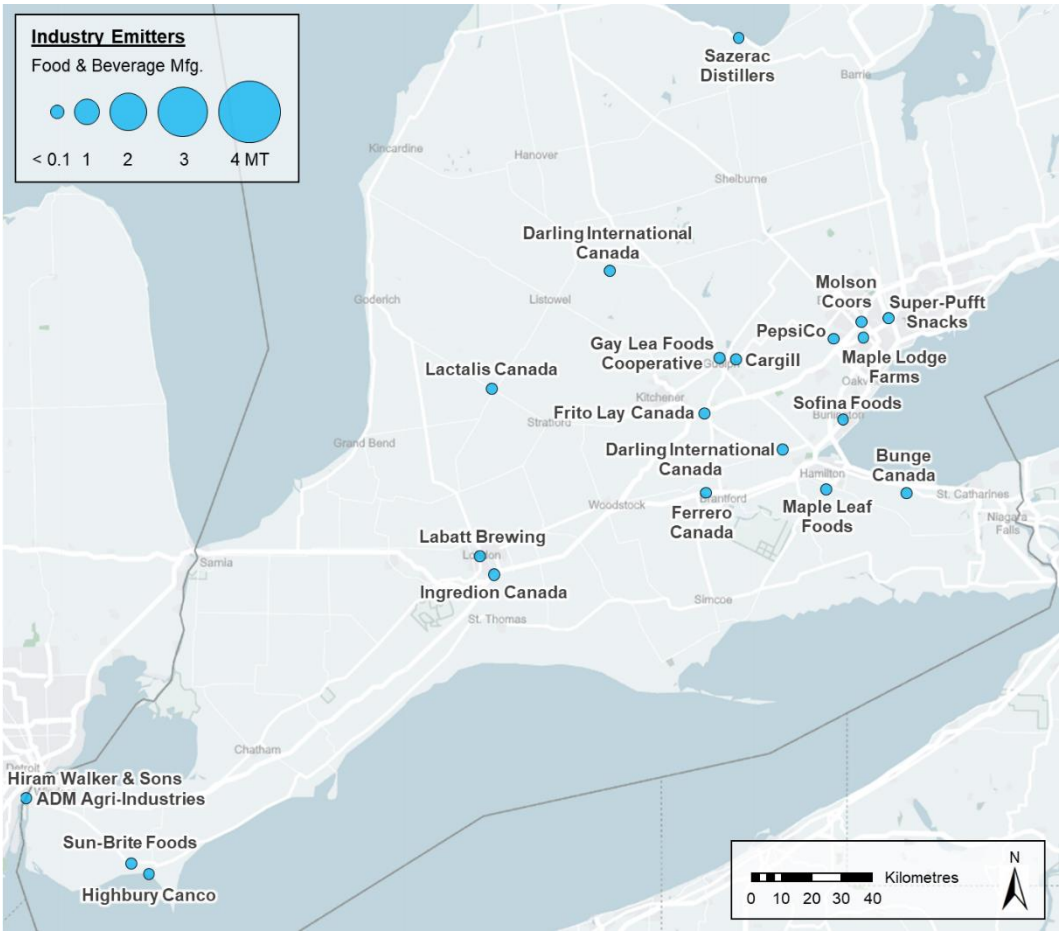

FIGURE 2-10 LOCATION OF FOOD AND BEVERAGE MANUFACTURERS (NAICS 311 & 312)

The highest emissions arise from grain and oilseed milling, including Ingredion's corn processing plant in London, Ontario (129 KT of CO_2 in 2020), and ADM Agri-Industries oilseed milling operation in Windsor, Ontario (75 KT of CO2 in 2020). The Hiram Walker & Sons distillery in Windsor, Ontario was the highest beverage industry emitter, with 70 KT CO_2 emitted in 2020. The emissions of other GHG's from this sector were very low, generally less than 1 tonne of CH_4 and N_2O, with few having slightly higher values.

ADM is a global leader in the implementation of CCS technology, and their Decatur project in the Illinois Basin is the world's first successful completion of a dedicated geological storage CCS project[77]. The project captured and stored CO_2 from ADM's ethanol plant in Decatur, Illinois, which is the biggest corn processing plant in the world, with over 4 MT of annual CO_2 emissions. While the company is continuing and pursuing further storage projects in the Illinois Basin[78], it seems unlikely to employ carbon capture

[77] https://investors.adm.com/news/news-details/2022/ADM-Carbon-Capture-and-Storage-Project-Earns-Top-Honors-from-Environment--Energy-Leader/default.aspx
[78] https://www.adm.com/en-us/standalone-pages/adm-and-carbon-capture-and-storage/

at its Windsor milling operation because of the much lower emissions (only 75 KT of CO_2 in 2020) and high cost of the technology.

In general, the food and beverage manufacturers in SW Ontario are planning to reduce their carbon emissions primarily through energy efficiencies, for example, through the use of renewable energy sources, as well as other process improvements[79]. Therefore, this industry sector is not expected to contribute to the geological storage requirements through CCS.

2.7 Transportation Equipment Manufacturing

The automotive sector is an essential and long-established part of Ontario's economy, contributing 16% of Ontario's manufacturing GDP (or $13.9 billion) in 2019, while employing nearly 100,000 workers in vehicle assembly and parts manufacturing[80]. Ontario ranks as the number two auto-producing jurisdiction in North America (after Michigan) and has the vehicle assembly facilities of five major global auto makers, namely Ford, General Motors, Honda, Stellantis (formerly Fiat Chrysler Automobiles (FCA) Canada), and Toyota.

In 2020, the transportation equipment manufacturing sector (NAICS code 336) emitted 488 KT CO_2. The majority of the emissions (around 80% of the total, or 387 kT CO_2) were from the main vehicle assembly plants, while the remainder originated from automotive part manufacturers. The locations of the emitters are shown in Figure 2-11, with details found in Appendix A.

In terms of other greenhouse gases (GHG's), the emissions of CH_4 and N_2O in 2020 were generally low, between 0.2 and 1.6 tonnes. However, the transmission and power train parts supplier Stackpole International emitted 3.7 tonnes of CH_4 and 48.6 tonnes of N_2O from it's powder metal manufacturing facility in Stratford, Ontario.

Automotive manufacturers are committed to reducing CO_2 emissions from new vehicles, primarily through electrification (i.e., production of electric vehicles). The five major auto makers have made significant investments toward this goal in their assembly plants in SW Ontario, amounting to over $10 billion since 2018[81]. This is in addition to the recently announced new 220-acre $5 billion electric vehicle battery manufacturing plant in Windsor, Ontario, by Stellantis and LG Energy Solution[82]. The plant is expected to be operational in 2024 and employ around 2,500 people in the Windsor area. It is unknown at this time what the annual CO_2 emissions will be from this large battery manufacturing facility. A second battery manufacturing facility was announced by Volkswagen's PowerCo in early 2023 for St. Thomas.

[79] Ingredion is investing in energy efficiencies at its London plant (https://www.canada.ca/en/natural-resources-canada/news/2019/04/canada-invests-in-energy-efficiency-improvements-in-london.html), Hiram Walker & Sons is converting to renewable electricity use by 2025 (https://corby.ca/en/hiram-walker); Bunge is pursuing low carbon sources of electricity and steam (Bunge, 2022, Global Sustainability Report).

[80] Government of Ontario (2019). Driving Prosperity: The Future of Ontario's Automotive Sector.

[81] Cywinski, M., 2022. Continued investment in Canadian automotive production. MRO magazine, July 2022.

[82] Stellantis March 23, 2022 Press Release (https://www.stellantis.com/en/news/press-releases/2022/march/stellantis-and-lg-energy-solution-to-invest-over-5-billion-cad-in-joint-venture-for-first-large-scale-lithium-Ion-battery-production-plant-in-canada).

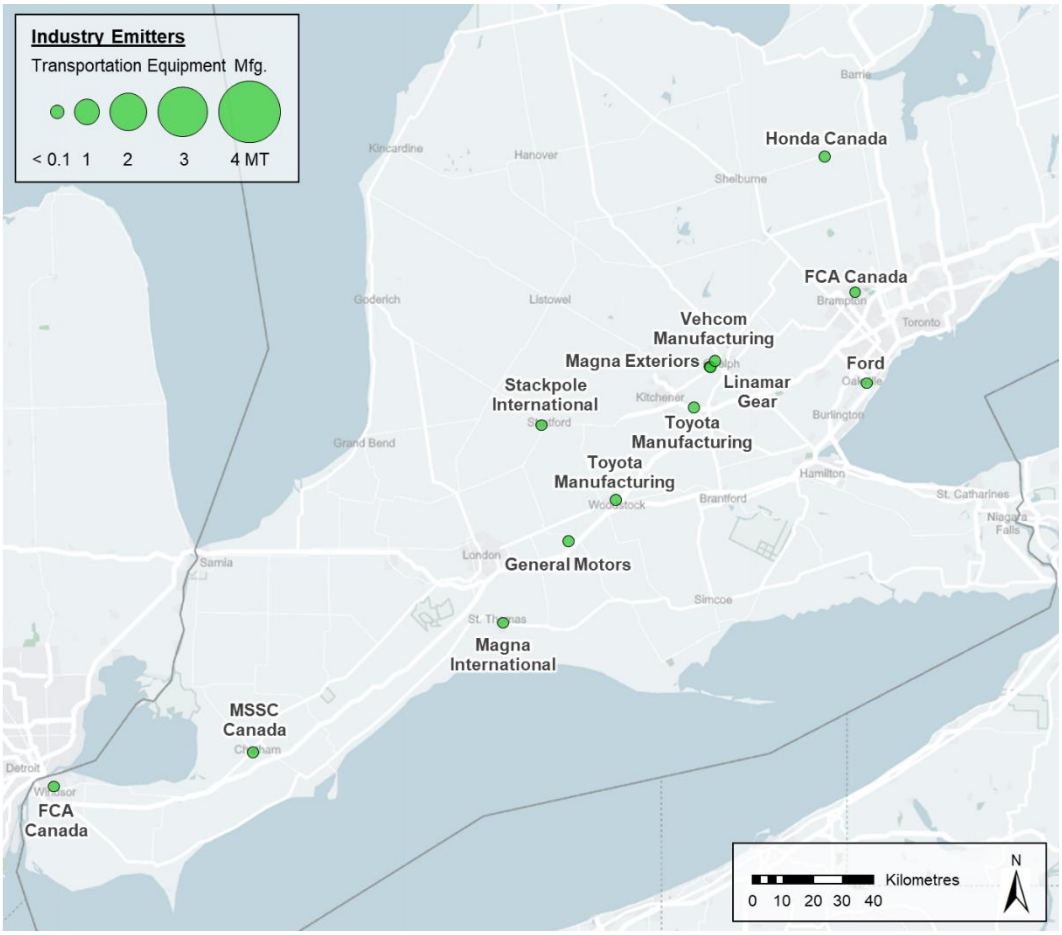

FIGURE 2-11 TRANSPORTATION EQUIPMENT MANUFACTURING FACILITIES (NAICS 336)

In terms of vehicle assembly, all five auto makers are planning to eliminate CO_2 from their manufacturing operations[83]. The decarbonization strategies are reliant on (1) reducing energy use through efficiency improvements and (2) switching to 100% renewable energy sources. The primary source of CO_2 emissions from auto manufacturing is the paint shop, particularly the heating required for the oven[84]. These emissions can be reduced through electrification (from renewable energy) or by switching from natural gas to hydrogen. Therefore, the automotive sector in SW Ontario is not expected to require any geological storage through CCS.

[83] See Ford Motor Company, 2022 Task Force on Climate-Related Financial Disclosure (TCFD) Report; General Motors, 2021 Sustainability Report; Honda, 2022 Sustainability Report; Stellantis, 2022 Sustainability Report; Toyota, 2021 North American Environmental Report.

[84] Giampieri, A., Ling-Chin, J., Ma, Z., Smallbone, A., Roskilly, A.P., 2020. A review of the current automotive manufacturing practice from an energy perspective, Applied Energy, Vol. 161, 114074.

3 REVIEW OF CO_2 CAPTURE AND TRANSPORTATION

Carbon capture is vital for reducing emissions from large industrial facilities and reaching the global net zero objectives[85]. According to the International Energy Agency (IEA), more than 1 Gt CO_2/year will need to be captured by 2030[86], requiring the construction of hundreds of new CCS facilities by the end of this decade. Furthermore, Bui and Danaci[87] have estimated that between 2800 and 4500 CCS plants of 1.7 MT/yr capacity will need to be commissioned between 2030 and 2060 to meet the IPCC 2°C target. Haszeldine and Singh Ghaleigh[88] have abbreviated this to*: "No CCS = No 2°C*".

Although many carbon capture technologies are mature, they have not reached widespread deployment primarily because of high costs, as well as other technological and bureaucratic challenges[89]. As stated by the Harvard Kennedy School report[90], CCUS is not economically competitive in 2022 in most of its applications, despite current levels of government support through tax policies.

Currently, there are around 35 commercial capture facilities in operation globally, with a total annual capture capacity of about 45 MT CO_2[91]. This includes both the Quest project[92] and those associated with the Alberta Carbon Trunk Line[93] near Edmonton, Alberta. Although over 200 new CCS facilities have been proposed and are planned to be capturing over 200 MT CO_2 per year by 2030[94], this is still far below the 1 GT CO_2/yr required by the net zero scenario.

Regarding SW Ontario, Figure 3-1 shows the estimated CO_2 capture volumes by 2030 based on analysis and discussions with industry representatives regarding their plans for decarbonization[95]. The total estimate is approximately 10 MT CO_2/year, including ~5 MT/yr from the steel industry in SW Ontario. No specific plans or proposals have yet been announced by most industry emitters regarding how these capture goals might be achieved, although the steel sector appears unique in that it has identified its plans and capital costs (see Section 2.1).

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[85] IEA (2020). Energy Technology Perspectives 2020 Special Report on Carbon Capture Utilisation and Storage: CCUS in clean energy transitions. Paris: International Energy Agency.

[86] IEA (2020). World Energy Outlook 2020. Paris: International Energy Agency

[87] Bui, M., and Danaci, D. (2022). Supply chain readiness for widespread deployment of carbon capture and storage, Chemical Engineering and Industrial Chemistry, May 19, 2022 Version 1 pre-print.

[88] Haszeldine, S. and Singh Ghaleigh, N., 2018. *Geological Factors for Legislation.* In *Carbon Capture and Storage: Emerging Legal and Regulatory Issues, 2nd Edition.* Edited by Ian Havercroft, Richard Macrory and Richard Stewart, Hart Publishing Plc., Oxford, UK.

[89] US Government Accountability Office (GAO) 2022, ibid.

[90] Moch, J.M., Xue, W., and Holdren, J.P. (2022). Carbon Capture, Utilization, and Storage: Technologies and Costs in the U.S. Context, Environmental and Natural Resources Program, Belfer Center for Science and International Affairs, Harvard Kennedy School, Cambridge, MA, January 2022.

[91] See IEA (2022). Carbon Capture, Utilization and Storage, Tracking Report - September 2022. Paris: International Energy Agency.; Global CCS Institute (2022). CO2RE Facilities Database. https://co2re.co/FacilityData

[92] Preston, C., 2018, ibid. (Shell Quest)

[93] Enhance Energy Inc. (2022). Alberta Carbon Trunk Line (ACTL) system. https://enhanceenergy.com/actl/

[94] IEA (2022), ibid. (tracking report)

[95] The estimated CO2 capture volumes are based on the analysis and assessment found in Section 2 of this report, as well as personal communications with representatives from the cement, lime, and steel industry sectors.

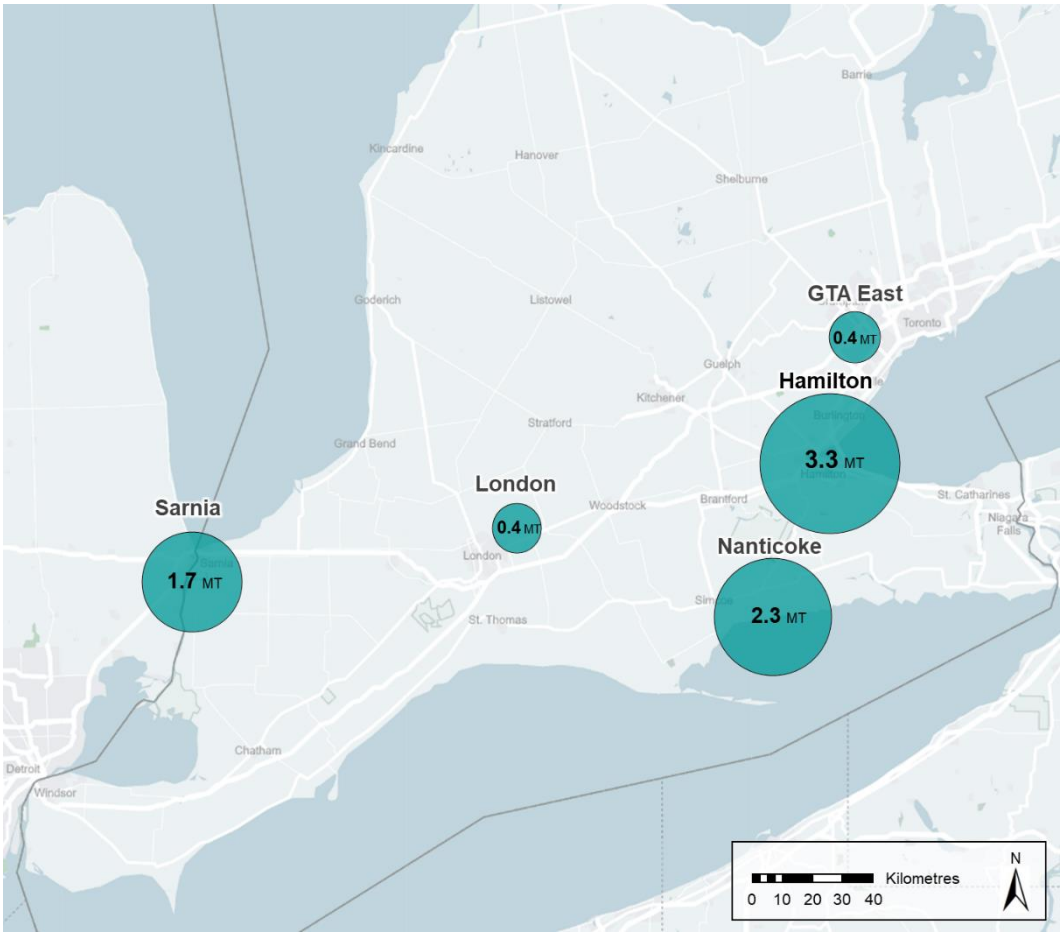

FIGURE 3-1 ESTIMATED CO_2 CAPTURE VOLUMES FOR SW ONTARIO

The main obstacle for decision making by industry is the high financial, technological, and regulatory uncertainty surrounding CCS implementation. The capture process itself typically accounts for 75 to 80 % of the total cost[96], however, these costs can vary widely depending on the application[97]. Figure 3-2 shows the estimated capture costs from different industry sources, highlighting the large range of variability both across and within each sector.

[96] See for example, Moch et al., 2022; and Alberta Innovates (2022). *Carbon Capture, Utilization, and Storage (CCUS): Technology Innovation to Accelerate Broad Deployment in Alberta.* Alberta Innovates, Edmonton, AB, April 2022.
[97] Global CCS Institute (2021). *Technology Readiness and Costs of CCS*. March 2021. (Kearns et al. report)

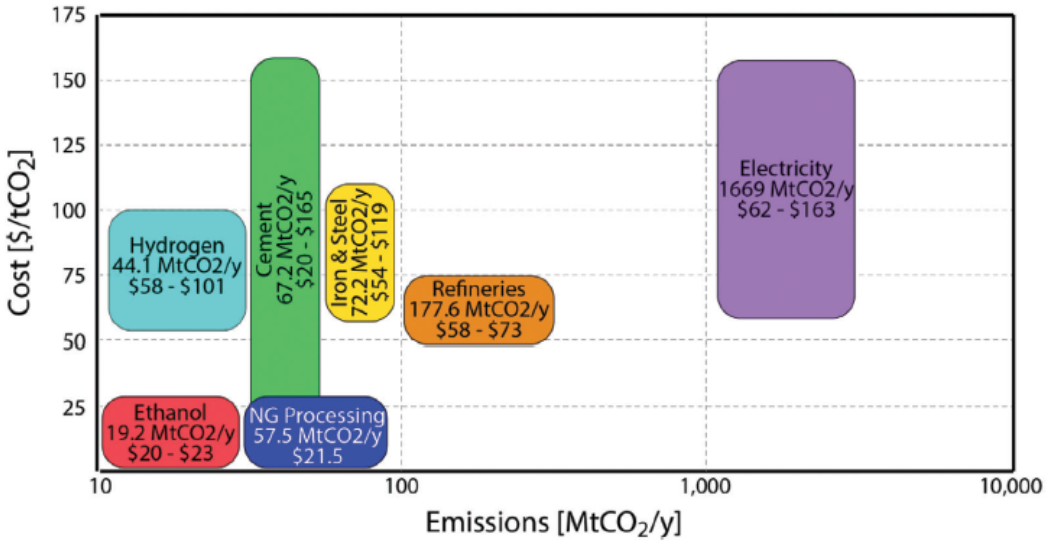

Figure 5. CO_2 capture cost per tCO_2-avoided and annual US emission from different sources (data from Tables 2–6). Emissions data are obtained from previous studies [21,32,41,48,49,51]. The reference for cost data for each item is as follows: Bio-ethanol: [27,35], Cement: [27,35,47], Electricity: [27,28,35], hydrogen [35], iron and steel: [9,27,37–39,52], natural gas processing [27], refineries [35].

FIGURE 3-2 ESTIMATED CARBON CAPTURE COSTS FOR DIFFERENT INDUSTRY SECTORS[98]

Technological development and innovation will be crucial for driving down the future cost of CCS and making CCS possible for the hard-to-abate sectors, such as steel and cement[99]. The objective of this section is to review the current status of available carbon capture technologies, with a particular focus of amine-based systems, and to identify their usage potential for the large emitters in SW Ontario. The discussion relies on the excellent technology summaries published recently by AECOM[100], Hong[101], Kearns at al.[102], Kazemifar[103], and the IEA[104].

The status of a particular technology is typically described by the technology readiness level (TRL)[105], which defines the technological maturity within an increasing scale of commercial deployment, from

[98] Kazemifar, F., 2022. A review of technologies for carbon capture, sequestration, and utilization: Cost, capacity, and technology readiness, *Greenhouse. Gas. Sci. Technol*. 0:1–31, DOI: 10.1002/ghg.2131.

[99] Global CCS Institute, 2021, ibid.

[100] AECOM (2022). *Next Generation Carbon Capture Technology. Technology Review Work Package 2*, Department for Business, Energy and Industrial Strategy, 60666122-WP2-RP-001, 24 May 2022.

[101] Hong, W.Y., 2022, ibid.

[102] Global CCS Institute (Kearns et al., report), 2021, ibid.

[103] Kazemifar, F., 2022, ibid.

[104] IEA, 2020, ibid.

[105] The TRL scale ranging from 1 to 9 was originally developed by NASA in the 1970's and has been widely used since to track the progress of technology development. The IEA has extended the scale to include TRL 10 and TRL 11 to describe the technology's readiness to meet energy policy objectives (IEA, 2020, ibid.). Others have also used the Commercial Readiness Index (CRI) introduced by the Australian Renewable Energy Agency to describe the commercialization status of the technology in addition to the technological readiness (see for example, AECOM, 2022, ibid., and Bui, M., and Danaci, D., 2022, ibid.). In this Section, we only consider the 1-9 TRL scale, which is also referenced in Figure 2-3 in Section 2.

TRL 1 – Concept level, to TRL 9 – Commercial application (see Figure 2-1). Amine based systems have been extensively developed and used (including at Quest and Boundary Dam) at TRL 9, and have become the benchmark for post-combustion capture from power plants[106]. However, these systems are very expensive, and may not be optimal for all industries.

It is also important to recognize that the lack of CO_2 transport and storage infrastructure can be a more critical barrier to deployment of CCS than the availability of suitable carbon capture technology[107]. Therefore, this section will also discuss the issues and challenges associated with CO_2 transportation in SW Ontario. Geological storage issues are examined in Section 5.

3.1 Amine Absorption Systems

Many different technologies have been devised to separate or capture CO_2 at different stages of industrial operations. While the primary focus has been on the effluent flue gas (i.e., post-combustion capture), the CO_2 can also be separated from the fuel itself by pre-combustion capture, during combustion (e.g., by oxyfuel or chemical looping combustion), or by direct separation (e.g., isolating process emissions from limestone calcination using Calix's technology)[108].

Chemical absorption with amine solutions is the most advanced carbon capture technology (TRL 9). It has been widely used for many decades in chemical production and purification of natural gas streams and is currently applied in both small and large-scale CCS projects around the world: e.g., electric-power generation (e.g. Boundary Dam in Saskatchewan and, from 2017 to 2020, Petra Nova in Texas), fuel transformation (e.g., Quest in Alberta) and industrial production (e.g., Emirates Steel in Abu Dhabi and Japan's COURSE50 Project, both for steel production, the Enid Fertilizer Plant in Oklahoma, and the Uthmaniyah CO_2-EOR demonstration project in Saudi Arabia)[109].

The process, shown in Figure 3-3, is based on the chemical reaction (absorption) of CO_2 from the flue gas into an amine based liquid solvent that forms a weak bond with the CO_2, thus removing CO_2 from the feed stream. The concentrated CO_2 is then released from the solvent in the regenerator (or stripper) by heat, which also regenerates the solvent that is then cooled and sent back to the absorber[110]. Common solvents consist of aqueous alkanolamines that include primary amines (such as monoethanolamine (MEA) and 2-amino-2-methyl-1-propanol (AMP)), secondary amines (such as diethanolamine (DEA)) and ternary amines (such as MDEA)[111].

[106] Bettenhausen, C., 2021. The life-or-death race to improve carbon capture, Chemical & Engineering News, 99(26), 18 July 2021.
[107] AECOM, 2022, ibid.
[108] See for example, Global CCS Institute, 2021, ibid., and Project LEILAC website - Pilot Plant, https://www.project-leilac.eu/leilac-pilot-plant.
[109] IEA, 2020, ibid.
[110] IECM, 2019, Amine-based Post-Combustion CO2 Capture, Integrated Environmental Control Model Team, Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA, January 2019.
[111] Hong, W.Y., 2022, ibid.

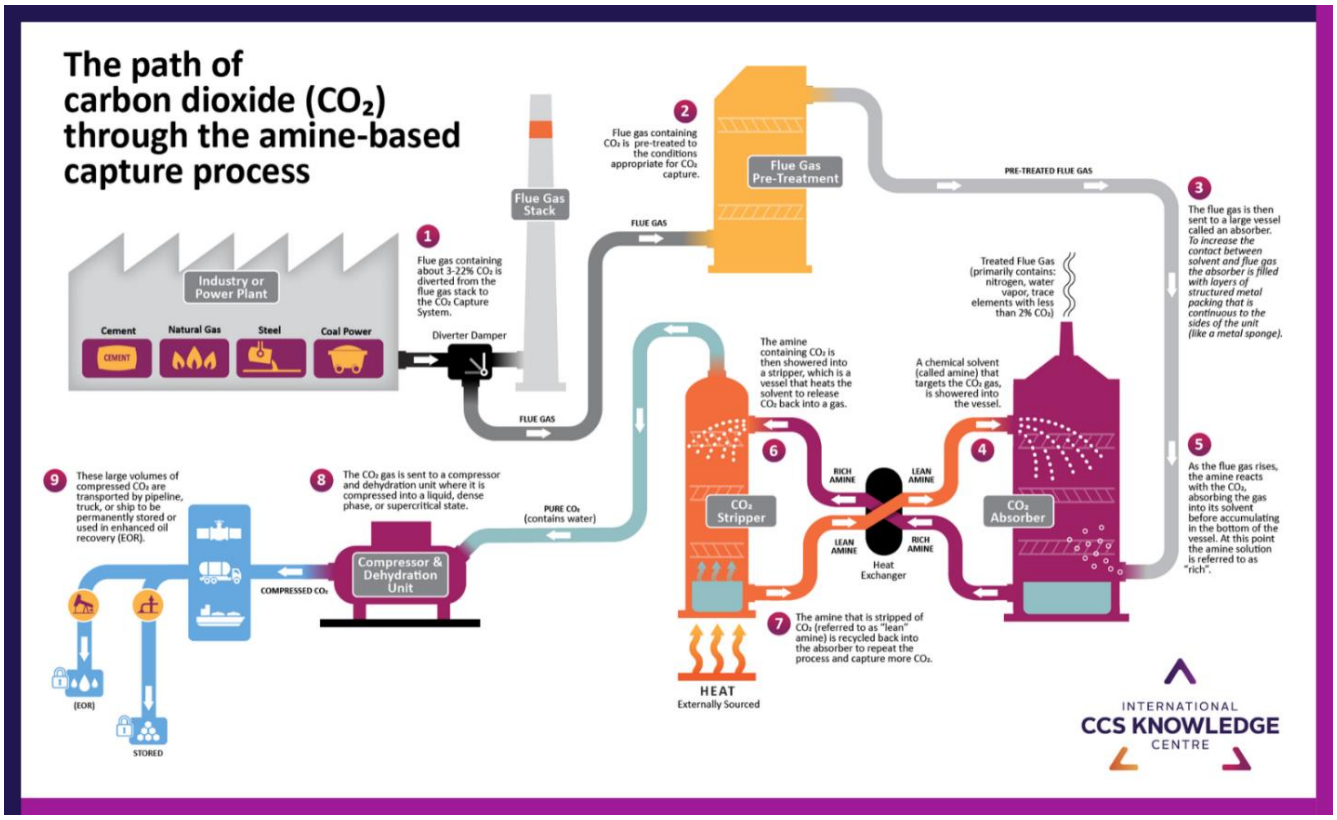

FIGURE 3-3 CARBON CAPTURE BY AMINE ABSORPTION

The most widely used absorbent for CO_2 separation applications has been 20-30 wt% aqueous MEA[112], due to its high CO_2 absorption capacity (4.09 mol CO_2 /kg solvent), high CO_2 recovery (typically between 85% and 90% vol.) and CO_2 purity above 99% vol.[113] Dow, Shell, Fluor, and others offer commercially ready MEA-based solutions for carbon capture[114].

Although the main advantage of post-combustion carbon capture technologies, such as amine scrubbing, is that they can generally be implemented without major changes to the industrial plant itself, the main drawbacks of MEA-based systems are (i) the high energy consumption during solvent regeneration, (ii) solvent degradation (due to the presence of SO_2 and NO_2 in the flue gas), and (iii) high equipment corrosion rate (due to the presence of O_2), which makes the process very costly to operate[115].

[112] Bui M, Adjiman CS, Bardow A, Anthony EJ, Boston A, Brown S., 2018, Carbon capture and storage (CCS): the way forward. Energy Environ Sci. 2018;11(5):1062–176.
[113] Li, K., Leigh, W., Feron, P., Yu, H., Tade, M., 2016. Systematic study of aqueous monoethanolamine (MEA)-based CO2 capture process: Techno-economic assessment of the MEA process and its improvements. Appl. Energy 165, 648–659.
[114] See for example, AECOM, 2022, ibid., and Global CCS Institute, 2022, State of the Art: CCS Technologies 2022, Technical Report.
[115] See for example, Wang, M., Lawal, A., Stephenson, P., Sidders, J., Ramshaw, C., 2011. Post-combustion CO2 capture with chemical absorption: A state-of-the-art review. Chem. Eng. Res. Des. 89, 1609–1624.; Bettenhousen, C., 2021, ibid.; Vega, F., Baena-Moreno, F.M., Gallego Fernández, L.M., Portillo, E., Navarrete, B., Zhang, Z., 2020, Current status of CO2 chemical absorption research applied to CCS: Towards full deployment at industrial scale. Appl. Energy 2020, 260, 114313.

In the cement industry, the requirement for pre-treatment of the flue gas to remove SO_2 and NO_2 and increased fuel consumption for heating increases these costs even more[116].

The high cost (both CAPEX and OPEX) is the main obstacle for the wider adoption of amine-based capture systems by the industry. To reduce costs, companies such as BASF, Linde, General Electric, and Carbon Clean, are working on advanced amines with chemicals such as piperazine alongside or, instead of MEA, to achieve better stability, kinetics, and thermodynamics[117]. However, some experts believe that amine systems can become only 10 to 20% more efficient[118], which may not be sufficient to make a successful business case in many industries. As a result, there has been increased research and development work involving alternate capture systems.

3.2 Alternative Capture Systems

Alternative carbon capture technologies have evolved quickly in recent years through testing in multiple R&D pilot projects around the world and through experience gained during deployment of large-scale projects, which has triggered further optimization of the technologies. Excellent lists and evaluations of these technologies can be found in AECOM's report to the UK government[119] and Table 2 in the Global CCS Institute's technology readiness report[120]. The Global CCS Institute has also recently published a catalogue of commercially available carbon capture technologies from leading technology providers, as well as promising emerging companies[121]. For highly innovative and experimental approaches, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) has compiled a compendium of R&D work it is sponsoring with respect to advanced CO_2 capture technologies[122]. The report provides technical summaries of over 120 projects in 2022, ranging from laboratory scale testing to pre-FEED and FEED studies.

The various carbon capture approaches can be categorized technologically into chemical absorption, physical separation (absorption, adsorption, cryogenic separation, or dehydration and compression), membranes, oxy-combustion, solid looping, and inherent or direct CO_2 capture. The maturity and status of each technology is generally described by their TRL, see Figure 2-3. Importantly, the TRL also reflects the level of uncertainty associated with both capture capacity and cost, with low TRL having higher uncertainty, and high TRL having lower uncertainty. Furthermore, TRLs are context specific, meaning that while a technology may be mature in one application, it may not be ready for use in other plants where process conditions differ significantly[123].

[116] Plaza, M.G., Martinez, S., Rubiera, F., 2020, CO2 Capture, Use, and Storage in the Cement Industry: State of the Art and Expectations, Energies 2020, 13, 5692; doi:10.3390/en13215692.
[117] See for example, Bettenhousen, C., 2021, ibid., and AECOM, 2022, ibid.
[118] Quote by Syrie Crouch, VP of CCS at Shell in Bettenhausen, C., 2021, ibid.
[119] AECOM, 2022, ibid.
[120] Global CCS Institute, 2021, ibid.
[121] Global CCS Institute, 2022, State of the Art: CCS Technologies 2022, Technical Report.
[122] NETL, 2022, Carbon Capture Program R&D Compendium of Carbon Capture Technology, U.S. Department of Energy, National Energy Research Laboratory.
[123] Bui, M., and Danaci, D., 2022, ibid.

Figure 3-4 shows a plot of the TRL versus estimated capture cost for some of the technologies and industry sectors. It is evident that the estimated capture cost can vary widely depending on the application. Technologies at the pilot stage (TRL 6-7) would be expected to have large uncertainty associated with their capture costs, as they have not yet been applied at the full commercial scale. Even for mature technologies (TRL 9), there is still significant uncertainty in the capture cost because it would depend on many local conditions and plant specific characteristics.

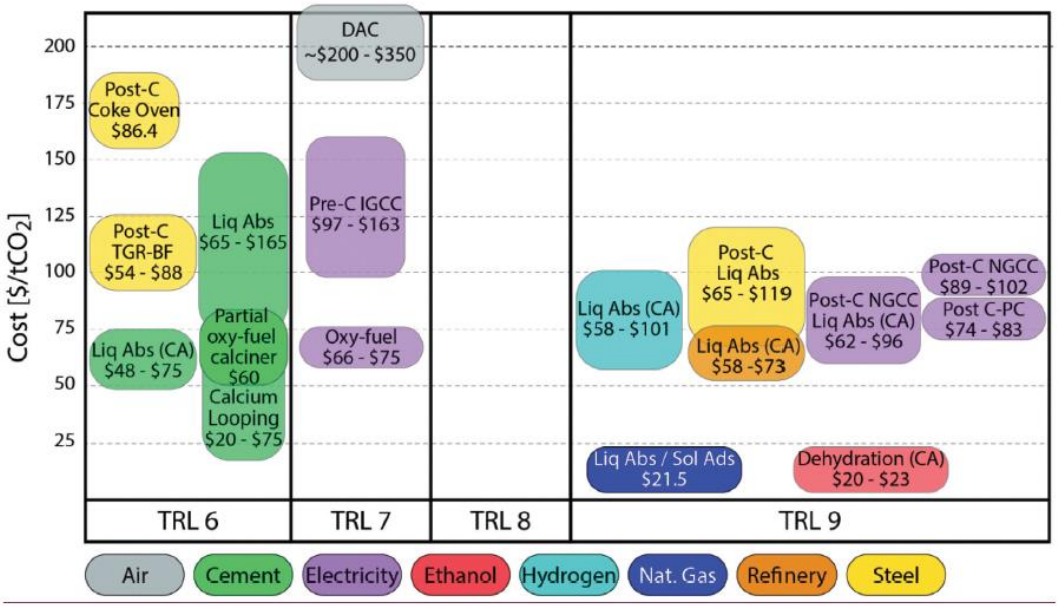

Figure 6. Cost and TRL for capture from different CO_2 source streams (data from Tables 2–6).
Abbreviations: *BF*: Blast furnace, *DAC*: Direct air capture, *IGCC*: Integrated gasification combined cycle, *Liq Sol*: Liquid solvent, *NGCC*: Natural gas combined cycle, *PC*: Pulverized coal, *PreC*: Precombustion, *PostC*: Postcombustion, *TGR*: Top gas recycling.
Notes: Items marked with (CA) indicate estimate obtained specifically for California taken from *EFI & Stanford University 2020*[35] and includes available federal and state tax credits and/or incentives. Data from *GCCSI 2017*[27] represents cost estimates for first-of-a-kind plants[9,27,35,37–39,47,52,59,61]

FIGURE 3-4 TRL VS. CAPTURE COST FOR DIFFERENT TECHNOLOGIES AND INDUSTRY SECTORS[124]

As discussed above, chemical absorption using amine-based solvents is the most advanced and widely used capture technique. In contrast, physical separation using liquid solvents (e.g., Selexol or Rectisol) rely on intermolecular interactions to dissolve the CO_2. They use less energy than chemical solvents but require high pressures and low temperatures. They are generally unsuitable for combustion flue gas and have been primarily used to remove CO_2 from natural gas and syngas.

Physical separation by adsorption involves the chemical or physical adsorption of CO_2 onto a surface of a solid sorbent. A wide range of materials have been used as CO_2 adsorbents including classic adsorbents (carbon, alumina, silica, zeolites) as well as new adsorbents (metal organic frameworks or MOFs, hydrotalcites, polymers, and high temperature metal oxides). The solid sorbents are usually regenerated by increasing temperature (temperature swing adsorption or TSA) or reducing pressure (pressure swing adsorption or PSA) or vacuum swing adsorption or VSA) to release the captured CO_2.

[124] Kazemifar, F., 2022, ibid.

Physical sorbent-based technology has mainly been used in industrial manufacturing processes, such as syngas and hydrogen manufacturing, and natural gas cleaning[125]. The applications typically involve proprietary solvents, VSA, or cryogenic separation techniques[126].

Similar to amine-based systems, membranes are actively being used in natural gas processing and other areas where the partial CO_2 pressure is high[127]. Membrane-based separation uses permeable or semi-permeable materials that act like a filter to separate CO_2 from the gas mixture. Various types of membrane systems have been developed for CO_2 capture, including polymeric membranes, electrochemical membranes, and solid membranes[128].

Oxyfuel separation involves the combustion of a fuel using nearly pure oxygen and the subsequent capture of the emitted CO_2. Because the flue gas is composed almost exclusively of CO_2 and water vapour, a high-purity CO_2 stream is obtained easily by dehydration. While oxyfuel combustion improves fuel efficiency, the main cost challenge is the required oxygen, which is typically produced commercially using energy-intensive low-temperature air separation[129]. The other significant issue for industrial applications is the requirement to re-build and re-engineer the existing plant in order to minimize air ingress and optimize the heat recovery systems[130]. The technology is currently at the large prototype or pre-demonstration stage (TRL 5 to 7) for CCS, however oxyfuel combustion has been used over time in the glass and steel industries and therefore has been technologically tested beyond TRL 7..

There are a number of reasons to use oxyfuel combustion other than that of fuel efficiency and technological maturity in other industries. From the perspective of of geological storage, pre-combustion using oxyfuel reduces the geological storage need by 10-20% because of its fuel efficiency in comparison with amine absorption systems. Furthermore, oxyfuel combustion has the potential to increase process efficiences substantially (~10%) when high temperature heat sources are required. Finally, in those jurisdictions with lower power costs, oxyfuel combustion is highly competitive with amine-based capture systems.

More recently, calcium looping, and chemical looping technologies are being explored for potential integration within industrial plants as more efficient, less toxic alternatives to current post-combustion capture processes (such as amine scrubbing)[131]. Calcium looping is one of the most promising CO_2 capture technologies for the cement sector[132]. These looping technologies transfer lime (calcium looping) or a metal oxide (chemical looping) between two reactors to produce a concentrated stream of CO_2[133]. These technologies can significantly reduce the energy penalty associated with CO_2 capture,

[125] Concawe (2020). *Technology Scouting – Carbon Capture: From Today's to Novel Technologies*. Report 18/20.
[126] IEA, 2020, ibid.
[127] Bettenhausen, C., 2021, ibid.
[128] Alberta Innovates, 2022, ibid.
[129] IEA, 2020, ibid.
[130] Plaza, M.G. et al., 2020, ibid.
[131] Kazemifar, F., 2022, ibid.
[132] Plaza, M.G. et al., 2020, ibid.
[133] Paul Fennell and Ben Anthony (editors), 2015, "1 – Calcium and chemical looping technology: An introduction," *Calcium and Chemical Looping Technology for Power Generation and Carbon Dioxide (CO2) Capture* (Sawston, United Kingdom: Woodhead Publishing, 2015).

however, because they are still in the pilot stage (TRL 5-7), they are not expected to be deployed at full scale prior to 2040[134].

Other recent developments include the inherent or direct CO_2 capture technologies based on the Allam cycle and Calix's advanced calciner. The Allam cycle is an innovative natural gas power generation technology that uses a special turbine and oxy-fuel combustion to produce stream of pure CO_2[135]. It can also be integrated with hydrogen production into an integrated power and hydrogen plant with 100 % CO_2 capture[136]. However, because replacing an existing combined cycle gas turbine (CCGT) power plant with an Allam plant will likely be even more expensive than fitting it with CCS[137], this technology is not likely to be used in SW Ontario in the near term because most of SW Ontario's gas plants are also quite new, i.e., less than 15 years old.

For cement and lime producers, Calix's advanced calciner is intended to capture the hard-to-abate process emissions in a reverse application of the calcium looping technology[138]. Powdered limestone is heated indirectly in a tubular reactor such that the CO_2 released during the calcination process can be directly captured[139]. The technology has low capital cost and low energy penalty, and is being piloted as part of the European LEILAC (Low Emissions Intensity Lime and Cement) project[140]. Given the TRL of 5-6, full scale application of this technology is not expected to be available until after 2030.

The primary challenge for industry decision makers today is the lack of commercially available low-cost capture technologies. The current amine-based capture systems are too expensive for most applications, therefore eliminating the possibility for a viable business case. At the same time, newer technologies offer potential capital and operational cost savings, but with high uncertainty in capture costs, rates, and implementation timelines. Therefore, further research and development is urgently needed in order to reduce the cost of the capture and to increase the technology readiness level of emerging technologies. Until these issues are resolved, the technologies that are most likely to be deployable by 2030 are mostly amine based solvent systems that can be developed by incremental improvements, with hopefully lower costs[141].

3.3 Transportation of CO_2 in SW Ontario

Transport of CO_2 from emission sources to storage location might be by any of the four means shown in Figure 3-5[142]. Today, pure CO_2 for food packaging is delivered by truck and, by 2030, relatively small

[134] Kazemifar, F., 2022, ibid.
[135] Allam, R., Martin, S. Forrest, B., Fetvedt, J., Lu, X., Freed, D., 2017, "Demonstration of the Allam Cycle: An Update on the Development Status of a High Efficiency Supercritical Carbon Dioxide Power Process Employing Full Carbon Capture," Energy Procedia 114 (2017): 5948–5966.
[136] Global CCS Institute, 2021, ibid.
[137] The Economist, 2022, Technology Quarterly - The long goodbye: Making natural gas emissions-free will be a challenge, June 15, 2022.
[138] Global CCS Institute, 2021, ibid.
[139] AECOM, 2022, ibid.
[140] Project LEILAC website, ibid.
[141] AECOM, 2022, ibid.
[142] Lu, H., Ma, X., Huang, K., Fu, L. and Azimi, M., 2020. Carbon dioxide transport via pipelines: A systematic review. *Journal of Cleaner Production*, *266*, p.121994.

volumes of CO_2 may be transported by road or rail to gas gathering hubs for purification and compression[143]. However, it is expected that in 2030 most industrially-generated CO_2 will be transported by pipelines, one of which already exists in Alberta as the Alberta Carbon Trunk Line (ACTL). Fortunately, CO_2 pipelines are mature technologies based on 30 years of experience in west Texas.

FIGURE 3-5 ADVANTAGES AND DISADVANTAGES OF THE MEANS OF CO_2 TRANSPORT

The cost of pipeline transport in SW Ontario will depend on whether the pipeline must be constructed through an urban or greenfield land and the various obstacles that must be considered, e.g., rivers, wetlands, other pipelines and rights of way, etc., and the provision for compression along the pipeline. Also important will be the diameter of the pipe itself and its length; a pipeline over 100 km long may need booster stations along its length that will add to its capital cost. A final issue determining cost of transport will be the degree of utilization of the pipeline. The ACTL is currently transporting only ~11%

[143] Hughes, R., 2022. *Prospects for an Ontario Carbon Grid and CCS Hubs for 2030.* CANMET presentation, University of Waterloo workshop, November 4, 2022.

of its 14.6 MT CO_2/yr[144] of its design capacity, which will no doubt increase as other emitters in central Alberta establish pipeline links to the ACTL.

Pipeline costs in Ontario will vary. A 36" (0.91 m) diameter natural gas pipeline in Lambton County cost ~$200M for 20 km of pipeline or ~$10 M/km, which is much larger than normal costs that average $3.5 M/km in SW Ontario[145]. This cost likely reflects the cost of a compressor and the prevailing cost of steel in 2022. Figure 3-6 illustrates a potential pipeline route for Eastern Canada that has been developed by CanmetENERGY to optimize transportation costs under uncertainty and shows ultimate CO_2 storage in depleted oil and gas fields offshore.

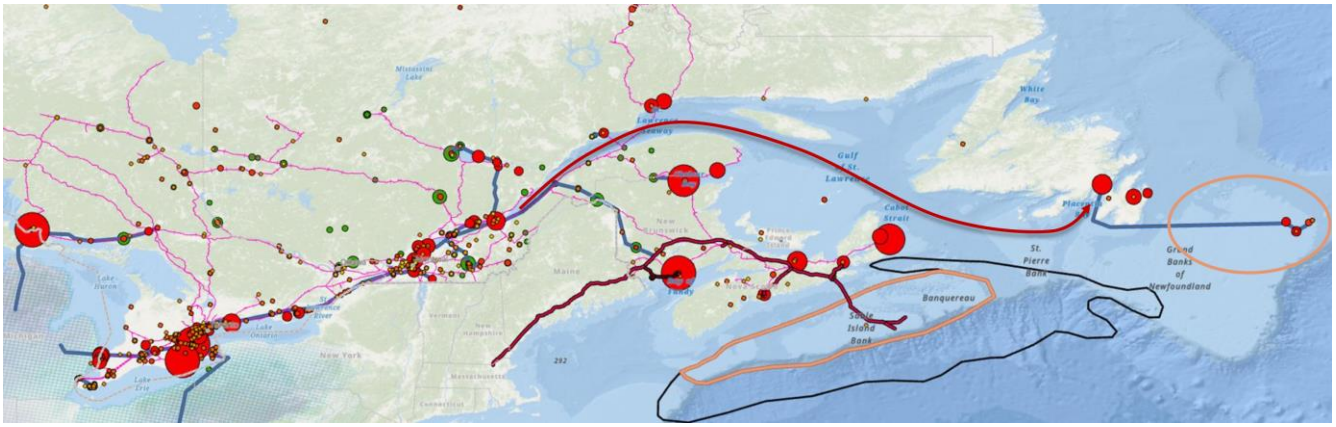

FIGURE 3-6 CANMET'S CONCEPTUAL CO_2 TRANSPORTATION PIPELINE NETWORK FOR EASTERN CANADA[146]

CO_2 transmission costs will also reflect the complexities that arise in treating the flue gases to ~99% purity, compressing, and then transporting the gas. CO_2 transmission will require corrosion-resistant steels and pre-treatment to strictly limit the amounts of impurities in the gas stream, notably oxygen, water, carbon monoxide and hydrogen sulphide. The gas itself will be transported as a dense (supercritical) phase at 10-15 MPa (Quest operates at 20 MPa[147]) or at lower pressure. BloombergNEF[148] estimates that the average pipeline project at approximately US$15-20/T CO_2, with feeder pipelines costing over US$15-20/T CO_2.

While road and rail CO_2 transport is considerably more expensive than pipelines, sea-borne transport may be cost comparable. One European project intends to provide barge transport from inland heavy industry, such as that in the Ruhr District and along the Rhine valley, to seaports such as Antwerp and Rotterdam. From there the CO_2 will be transported as of 2026 by ship to Carbfix in Iceland, where the

[144] The Alberta Carbon Trunk Line (ACTL) system was commissioned in July 2020 to capture CO_2 at the Sturgeon bitumen refinery and at a nearby fertilizer plant in Redwater, north of Edmonton. The CO_2 is transported south a distance of 240 km to mature oil fields in central Alberta for use in EOR. It is capable of transporting as much as 14.6 million tonnes of CO_2 per year via a 0.4 m diameter pipe, which represents approximately 20% of all current emissions from Alberta's oil sands plants. The network of pipelines leads to Clive, Alberta, where the CO_2 is injected into a deep carbonate oilfield.

[145] Costs provided by J. Cadotte, Enbridge, 2021-08-27.

[146] From a presentation by Nicole Bond, CANMET-Energy Ottawa, to the Hard-to-Abate Club, 4 November 2022.

[147] Rackley, S.A., 2017. *Carbon Capture and Storage*, 2nd edn. Butterworth-Heinemann, Boston.

[148] BloombergNEF, 2022. *CO_2 Transport and Storage: Scale Required.* 22 June.

CO_2 will be injected into basaltic bedrock and be trapped as a carbonate mineral[149]. Alternatively, it could be transported to depleted North Sea oil and gas fields.

This raises the possibility of gathering CO_2 from the major industrial emitters in Ontario, most of which are located along the shorelines of the Great Lakes, from Sault Ste. Marie to Kingston. Such 'laker' transport may become attractive in the Canadian context for CO_2 transport to Montreal and then by ship to depleted oil and gas fields off Newfoundland and Nova Scotia. This latter step is already under consideration by CanmetENERGY but based first on pipeline transport to Montreal. However, each port from which CO_2 may be shipped will require expensive infrastructure to cool, liquefy, pressurize, and store CO_2 prior to shipment, therefore this will not be an inexpensive option. Furthermore, to attain year-round CO_2 transportation, it will be necessary to have short pipeline sections along the Welland Canal and the St. Lawrence Seaway. Should onshore CO_2 storage be limited and pipelines prohibitively expensive or socially unacceptable in urban areas, this option would make the best use of the Great Lakes as a transportation route as it has since Canada's founding as a nation.

3.4 Conclusions

At the time of writing (early 2023), we conclude that perhaps ~10 MT CO_2 per year will be captured in SW Ontario by 2030 and then only on the basis of proven geological storage nearby. Without proven storage, plans for carbon capture and pipeline construction will not proceed to procurement, i.e., the Final Investment Decision (FID). At present, only the steel sector in SW Ontario appears ready to commit preliminary expenditures for carbon capture and geological storage under the threat of paying a federal carbon tax of $170/tonne CO_2 in 2030. Therefore, demonstration of available storage is critical to the development of CCS in SW Ontario, without which FIDs will be postponed.

Finding the capital involved to build a carbon capture plant – of the order of CDN$1 billion[150] for 1 MT/$CO_2$/yr – will be subject to competition from industries in the US or, more particularly, US-based plants of the same corporation that will have access to the investment tax credits (ITC) contained within the US 2022 Inflation Reduction Act. At present, the ITC incentives offered by the federal government to stimulate Canadian CCS pale in comparison with the 45Q tax credits available in the USA[151]. The federal 2023 budget allows ITCs only to dedicated geological storage of CO_2 in western Canada[152].

The 2020 revision of the North American Free Trade Act offers heavy industry located in Ontario – cement, oil refining, and chemicals[153] – the option of shutting down production in SW Ontario, relocating to the USA and subsequently importing the product that they would otherwise produce in and export

[149] https://dan-unity.dk/dan-unity-and-victrol-to-ship-the-co2-from-inland-europes-largest-industry-emitters-to-safe-storage/

[150] The International CCS Knowledge Centre, 2020, *Incentivizing Large-Scale CCS in Canada: A White Paper.* Regina, SK. The cost of BD3 retrofit and carbon capture plant was ~$1.5B for a design capacity of 1 MT/yr, 90% CO_2 capture rate.

[151] See BMO 22 August 2022, Canada Falling Behind in CCUS Policy, Following U.S. Upgrade. It estimates that Federal incentives will cover <25% of CCS costs sanctioned by 2030 compared with over 60% of costs in the US covered by the Inflation Reduction Act. According to BMO's March 2022 analysis of the Pathways project in Alberta, the Quest project in Alberta was funded with ~70% of CAPEX and >50% OPEX costs.

[152] https://www.budget.canada.ca/2023/report-rapport/chap3-en.html#a5. Only BC, Alberta and Saskatchewan are included.

[153] Steel is excluded here because none of the three major primary producers has production facilities in the US with which to supply Canada. Therefore, to these companies, CCS challenges are of an existential kind.

from Ontario to the US. The potential for loss of jobs and associated tax base would be considerable. In this way, Ontario would experience industrial decarbonization by deindustrialization.

Two CCS workshops, which were held in late 2022 by the University of Waterloo to support the preparation of this Road Map, exposed the deep concern among Ontario's heavy industries about the challenge of raising both capital (CAPEX) and operational (OPEX) financing for CCS in the face of the federal carbon tax. Assuming technological readiness and available geological storage, the financial incentives for CCS will be the critical criterion for investment[154,155]. Viewed from a corporate perspective, the comparative investment of CAPEX in a CCS project at a plant in SW Ontario versus a similar project at the corporation's plant somewhere in the US Mid-West would also depend on several other factors[156]:

- Accessibility and potential costs of CO_2 capture, transportation, and geological storage.
- The scale of emissions: higher emitting plants would have leverage against the fixed costs of CAPEX.
- A CO_2 emissions profile with higher CO_2 concentrations in the flue gas will result in lower capture costs.
- Regulatory pathway: has the jurisdiction established a clear regulatory pathway to licensing all aspects of CCS?
- Will there be social acceptance of a CCS hub, i.e., will it be perceived as a community benefit or will it raise concerns of vaguely perceived subsurface threats (as was the case with 'fracking' and nuclear waste disposal)?
- Will the apparent costs of electric power, or natural gas, or water treatment indicate high OPEX, and will these utilities be readily available at the scale required?

3.5 Recommendations

It is recommended that:

> ***1: The federal and provincial governments ensure the proven availability of 10 MT/yr of geological CO_2 storage capacity by late 2025 in SW Ontario to allow manufacturing industry to proceed with FIDs regarding carbon capture and to commit to pipeline construction[157].***

[154] Abdulla et al., 2021, ibid. The conclusions in this article were based on US experiences.

[155] "*If the market for CO_2 changes due to the development of CO_2 transportation and storage infrastructure and payment mechanisms for the capture and storage of CO_2, then opportunities will be created for increased levels of capture and storage from facilities that naturally generate a concentrated stream of CO_2*." From AECOM, 2022, *Next Generation Carbon Capture Technology*, prepared for the UK Department of Business, Energy and Industrial Strategy. Glasgow, UK.

[156] David Bangma, Director of Innovation, Ash Grove Cement, Mississauga ON, personal communication, 3 February 2023.

[157] Jeff Cadotte, Enbridge, indicated a 4-year requirement for pipeline construction (if and only if the regulatory environment is established) at a meeting of vulnerable industries at CMAT Hamilton, December 6, 2022.

2: Consideration should be given to the possibility of laker (ship) transportation of CO_2 through the Great Lakes system as an insurance should geological CO_2 storage fail to meet current expectations and to provide a lifeline to industrial emitters distant from potential geological storage hubs.

4 MITIGATION: IMPLICATIONS FOR REDUCING CO_2 GENERATION

The objective of this section is to examine these mitigation strategies in more detail, including the implications related to the subsurface storage of hydrogen in SW Ontario.

High cost is a major barrier to the widespread adoption of CCS. Current capture systems based on amine technology consume large amounts of energy, making them uneconomical in many applications and situations. While the development and advancement of new technologies will be crucial for driving down the cost of CCS in the future, it is also imperative to determine how to improve and lower the costs of existing technologies and processes.

In general, the financial burden posed by CO_2 to the industry may be mitigated by (1) reducing the cost of capture and CCS in general, and (2) reducing the generation and emission of CO_2.

In a broader context, the issue of CCS cost can be improved by strategies such as demonstrations and pilot projects, the formation of CCS hubs, and utilization of the captured CO_2. Demonstration projects allow the testing of new technologies under real-world conditions, which helps not only to identify risks across a full range of conditions, but also optimize the system, reduce uncertainties and costs[158], and develop viable business models[159]. The development of industrial CCS hubs helps reduce costs and counterparty risk by common usage of both transport and storage infrastructure, while CO_2 utilization through EOR and other uses can provide an added revenue stream to CCS facilities and help offset the cost of capture.

The cost of capture is also impacted by the capture efficiency or capture rate[160]. Most carbon capture facilities operating at industrial plants today are designed to capture around 90% of the CO_2 from the flue gas[161], which means that significant mass of CO_2 emissions will remain. The energy requirement of CO_2 separation is primarily a function of the flue gas CO_2 concentration or partial pressure, with dilute streams requiring larger equipment, more time, more energy, and hence higher cost. While the cost of increasing capture rates in some carbon capture projects can be highly non-linear[162], a techno-economic study by Danaci et al.[163] found that in most cases, increasing the capture rate from 90 to 95% has a negligible impact on capture cost, thereby reducing CO_2 emissions at virtually no additional cost. However, as denoted by researchers at MIT[164], the closer a CCS system gets to 100 percent efficiency, the harder and more expensive it becomes to capture additional carbon dioxide.

Given the high energy requirements of capture systems, there is strong potential for cost reduction through energy conservation and efficiency improvements. At the plant level, emission reductions can

[158] International CCS Knowledge Centre, 2018, *The Shand CCS Feasibility Study Public Report*, November 2018.
[159] US Government Accountability Office, 2022, ibid.
[160] Brandl, Patrick et al. "Beyond 90% capture: possible, but at what cost?" *International Journal of Greenhouse Gas Control* 105, Feb. 2021. doi:10.1016/j.ijggc.2020.103239.
[161] International Energy Agency, 2022, *Carbon Capture, Utilisation and Storage tracking report*, September 2022.
[162] AECOM, 2022, ibid.
[163] Danaci, D., Bui, M., Petit, C., and Mac Dowell, N., 2021, En Route to Zero Emissions for Power and Industry with Amine-Based Post-combustion Capture, *Environmental Science & Technology*, 55, 10619−10632.
[164] MIT Climate Portal - https://climate.mit.edu/ask-mit/how-efficient-carbon-capture-and-storage.

be achieved through electrification and shifting to hydrogen-based fuels, however at a significant cost. The generation of blue hydrogen from natural gas will also result in additional CO_2 emissions, which will require sequestration. Along with CCUS itself, these mitigation measures are critical for decarbonizing industrial emissions, and account for around 50% of the cumulative emission reductions in IEA's net zero scenario, as shown in Figure 4-1.

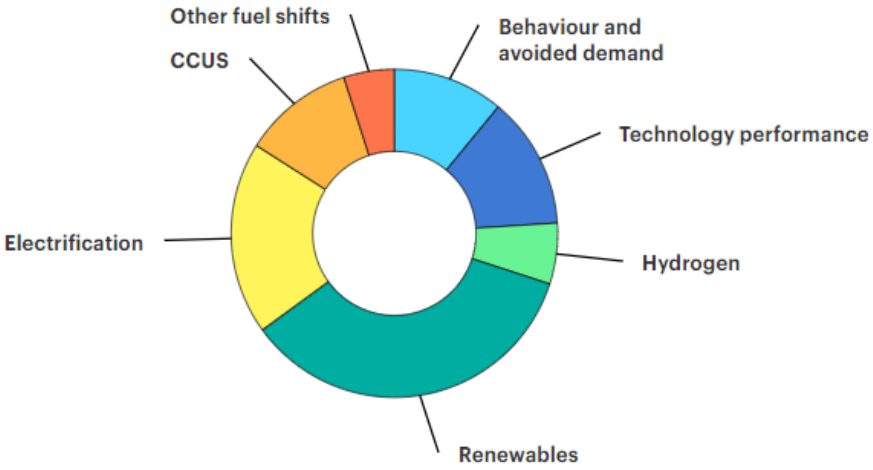

FIGURE 4-1 CUMULATIVE EMISSION REDUCTION BY MITIGATION MEASURE IN THE IEA'S NET ZERO SCENARIO, 2021-2050[165]

4.1 Building Energy Conservation and Efficiencies into CCS Systems

There is significant potential for cost savings through energy conservation and efficiency improvements of both existing industrial processes, as well as the proposed CCS systems.

Beyond the recognized benefits of electrification and use of alternative fuels for heating, a range of technologies and strategies are available for efficiency improvements and emissions reductions in existing facilities in the chemical industry[166], petroleum refining[167], cement production[168], and iron and steel manufacturing[169]. These include, for example, making changes to raw materials (e.g., using decarbonated materials in clinker production in the cement industry, switching/substituting feedstocks in chemical manufacturing, or using alternative reducing agents, such as wood charcoal, in the sintering process in steel making), upgrading process equipment, such as motors, pumps, grinders, etc. with

[165] International Energy Agency, *Cumulative emissions reduction by mitigation measure in the Net Zero Scenario*, 2021-2050.
[166] Vooradi, R., Anne, S.B., Tula, A.K., Eden, M.R., and Gani, R., 2019, Energy and CO2 management for chemical and related industries: issues, opportunities, and challenges, *BMC Chemical Engineering*, https://doi.org/10.1186/s42480-019-0008-6.
[167] Byrum et al., 2021, ibid.
[168] ISED, 2022, ibid.
[169] See for example, McKinsey & Company, 2020, *Decarbonization challenge for steel,* June 3, 2020.; Carpenter, A., 2012, *CO2 abatement in the iron and steel industry*, IEA Clean Coal Centre Report CCC/193, ISBN 978-92-9029-513-6, January 2012.

more energy efficient models, utilizing electricity exclusively from renewable energy sources, and recovering process heat to generate additional steam or electricity, among others.

While all industries are continually making efficiency improvements to their operations, this also means that high performers are already operating at close to optimum levels, leaving very little opportunity for further CO_2 emission reductions through efficiency improvements[170]. The mitigating measures can also be cost intensive and must be weighed against the potential benefits from emissions reductions (i.e., carbon tax) and/or productivity improvements.

In terms of CCS systems, the capture element is generally accepted to have the greatest impact on energy efficiency and cost. Many studies have looked at efficiency improvements to various aspects of the capture systems, including compressor performance[171] and other factors[172]. While new capture technologies offer potentially significant gains in energy efficiency and cost savings, amine-based solvent systems appear to have become the default carbon-capture system choice. However, it is entirely possible that oxyfuel combustion will increasingly offer competition when further demonstrations of its utility are published.

Amine health and maintainability are critical factors in the economics of operating post-combustion capture amine technology[173]. Particulates present in the flue gas lead to amine degradation, which challenges the optimal operation of the system. The utilization of advanced amines (e.g., KS-1, Cansolv, APBS)[174] may provide higher absorption rates and decreased solvent degradation, thereby significantly decreasing the cost of capture and cost of CO_2 avoided as compared to MEA based systems[175]. Studies have also looked at optimizing the overall energy-efficiency of amine-based capture systems for potential energy and costs savings[176]. As an example, waste heat from the kiln flue gas in

[170] For example, the EEIP estimates a maximum reduction of only 10% in CO2 emissions for the iron and steel sector in the EU through efficiency improvements - https://ee-ip.org/en/article/decarbonisation-of-industrial-heat-the-iron-and-steel-sector-1732.

[171] Jackson, S., and Brodal, E., 2019, Optimization of the Energy Consumption of a Carbon Capture and Sequestration Related Carbon Dioxide Compression Processes, *Energies* 12, 1603, doi:10.3390/en12091603.

[172] See for example, Skorek-Osikowska, A., Kotowicz, J., and Janusz-Szymanska, K., 2012, Comparison of the energy intensity of the selected CO2-capture methods applied in the ultra-supercritical coal power plants, *Energy Fuels*, 26,, pp. 6509-6517.; Hasan, S., Abbas, A.J., and Nasr, G.G., 2021, Improving the Carbon Capture Efficiency for Gas Power Plants through Amine-Based Absorbents, *Sustainability*, 13(1), 72, https://doi.org/10.3390/su13010072.

[173] International CCS Knowledge Centre - https://ccsknowledge.com/news/standardized-testing-eliminates-amine-based-ccs-barriers.

[174] AECOM, 2022, ibid.

[175] Danaci et al., 2021, ibid.

[176] See for example, Jacobs, B., Tantikhajorngosol, P., Hill, K., Ruffini, J., Wilkes, S., Srisang, W., Feng, Y., Daverne, D., and Nelson, C., 2022, Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities, *16th International Conference on Greenhouse Gas Control Technologies, GHGT-16,* 23rd -27th October 2022, Lyon, France.; Yuan, B., Zhan, G., Chen, Z., Li, Y., Wang, L., You, C., and Li, J., 2022, Intrinsic insight of energy-efficiency optimization for CO2 capture by amine-based solvent: effect of mass transfer and solvent regeneration, *International Journal of Greenhouse Gas Control*, 118, July 2022, 103673.; Hasan et al., 2021, ibid.

cement production[177] or iron and steel production[178] could be used to generate steam for the stripping section of the capture plant.

The main concern with these capture systems is that the degradation products and operational challenges are unique to each flue gas stream and amine combination, making it difficult to predict the overall performance and capture cost with high certainty across varying industrial applications[179]. Knowledge gained from projects such as Boundary Dam have shown that significant cost savings can be realized in second-generation capture facilities[180], however, the results are only applicable to similar facilities (i.e., coal-fired electricity generation in this case). Significant uncertainties remain regarding the potential degree of cost savings and emission reductions in other types of industrial applications, highlighting the urgent need for more pilot plants and demonstration projects.

4.2 Electrification of Industrial Processes Reducing Gaseous Emissions

Electrification is one of the key pillars in the global energy transition and is expected to provide around one-fifth of the cumulative emission reductions in IEA's net zero scenario (shown earlier in Figure 4-1). While majority of the reductions are expected to come from the road transport sector (i.e., light-duty vehicles) and space heating (i.e., installation of heat pumps), electrification of the industry sector is also important, but is expected to occur more slowly because of the highly competitive market, long lifetime of equipment, and relatively cheap cost of fuel (i.e., natural gas)[181].

Currently, the global industrial sector uses electricity to power only around 20% of its energy needs[182], with the majority, or around 45% derived from fossil fuel combustion for heat, and the remaining 35% consumed as feedstock[183]. There is high potential for electrification of low- to medium-temperature heating applications, e.g., using readily available electric heat pumps and boilers, however, because equipment powered by electricity offers no productivity or efficiency advantage over equipment powered by fossil fuels, there may be little financial incentive to replace the equipment. And unlike fossil fuels which can be stored on-site, the availability and reliability of the electricity supply is a major concern for the industry, with potentially costly production losses resulting from service interruptions.

As shown in Figure 4-2, there are also many other key industrial processes, especially those requiring high heat, which are much more challenging to electrify, such as cement, chemical, and steel production[184].

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[177] Arachchige, U.S.P.R., Kawan, D., Tokheim, L-A., Melaaen, M.C., 2014, Waste Heat Utilization for CO2 Capture in the Cement Industry, *International Journal of Modeling and Optimization*, Vol. 4, No. 6, pp. 438-442.

[178] Carpenter, 2014, ibid.

[179] According to Corwyn Bruce, VP of Technical Services at the International CCS Knowledge Centre, the research currently available on post-combustion amine-based carbon capture is insufficient for adequately understanding interactions between amines and flue gases. - https://ccsknowledge.com/news/standardized-testing-eliminates-amine-based-ccs-barriers.

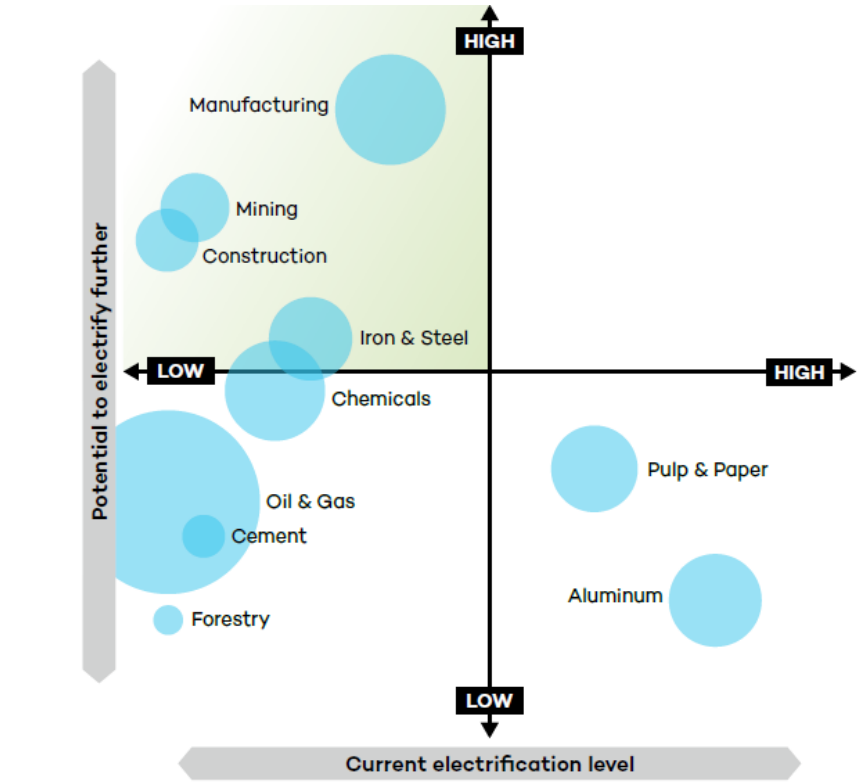
[180] The International CCS Knowledge Centre, 2018, *The Shand CCS Feasibility Study Public Report*, November 2018.

[181] International Energy Agency, 2022, Electrification tracking report, September 2022.

[182] This figure is slightly higher at 25% for the industry sector in Canada (International Institute for Sustainable Development, 2022, Electrifying Canada - Industrial Electrification, May 2022).

[183] McKinsey & Company, 2020, *Plugging in: What electrification can do for industry*, May 28, 2020.

[184] International Institute for Sustainable Development, 2022, *Electrifying Canada - Industrial Electrification*, May 2022.



Note: Bubble size reflects current total energy consumption.
Source: Produced by Dunsky Energy + Climate Advisors for Electrifying Canada, 2022.
Data sources: Langlois-Bertrand et al., 2021; Natural Resources Canada, 2020.

FIGURE 4-2 POTENTIAL FOR INDUSTRY ELECTRIFICATION (COPIED FROM IISD, 2022, IBID.)

In the cement industry, tests are under way in kiln electrification using plasma generators and microwave energy[185] and rotodynamic heaters[186]. Besides eliminating emissions from heating, the added benefit of electric kilns would be the much higher concentration of CO_2 in the flue gases, which would allow easier capture and purification of CO_2 from the process emissions. Combusting hydrogen as a fuel is also being considered, however, hydrogen flames have a relatively low emissive power, making them unsuitable for clinker manufacturing in conventional kilns[187]. Both electric and hydrogen approaches are in early stages of research and testing and are not expected to provide a widespread solution in the near term[188]. These solutions would also require significant capital investment for the replacement or significant alteration to the existing facilities.

[185] See for example, EEIP - https://ee-ip.org/en/article/deep-decarbonisation-of-industry-the-cement-sector-1773; Wilhelmsson, B., Kollberg, C., Larsson, J., Eriksson, J., and Eriksson, M., 2018, *CemZero - A Feasibility Study Evaluating Ways to Reach Sustainable Cement Production via the Use of Electricity*. Vattenfall and Cementa, 2018.

[186] Coolbrook – http://coolbrook.com/.

[187] Plaza et al., 2020, ibid.

[188] Perilli, D., 2022, Update on electric cement kilns, *Global Cement News*, 15 June 2022. - https://www.globalcement.com/news/item/14256-update-on-electric-cement-kilns

The study by Byrum et al.[189] provides a good overview of the technological challenges and pathways for decarbonizing petroleum refining, including opportunities for electrification. Reducing emissions at refineries is complex compared with other industries because individual facilities contain many dispersed emission sources that can also vary greatly in their compositions. Combustion from stationary sources accounts for approximately 63% of emissions, with around 31% contributed by process emissions from fluid catalytic crackers (FCCs) and steam methane reformers (SMRs)[190]. Refineries derive less than 10 percent of their energy from electricity, which is the lowest of all industrial sectors[191]. The main reason for this, and the key obstacle for electrification, is the refinery fuel gas (RFG), which is a by-product of refining that is used as the major source of heat at the plants. Replacing this fuel with electricity would not only be costly but would also create a waste management problem for the unused gas. As a result, electrification is likely to hold a relatively small position in the energy mix for petroleum refining[192].

The chemical industry also relies heavily on fossil fuels, both as a feedstock and an energy source, with nearly 80% of energy use derived from combustion heat required by reactions and separation processes[193]. A recent study by Mallapragrada et al.[194] outlines some of the key opportunities for electrification of the chemical industry, including direct heating with electricity, electrochemical production of hydrogen for process heat generation, direct use of electricity for manufacturing of chemical products via electrochemistry, and electricity-powered plasma reactors. The significant potential of electrochemical processes over energy- and carbon-intensive thermochemical processes has also been discussed by others[195], however, many barriers remain including the need for new catalysts and the challenge of scaling up[196]. Switching to direct heating with electricity or hydrogen would also require material changes and retrofits to existing facilities, increasing the cost of these options in contrast to the relatively low cost of fossil-derived heat today.

In iron and steel manufacturing, coal still meets most of the energy demand in the integrated blast furnace (BF)/basic oxygen furnace (BOF) steel making route[197]. Electrification of this sector can be achieved with electric arc furnaces (EAF) using steel scrap or direct reduced iron (DRI) as their raw material[198]. ArcelorMittal Dofasco in Hamilton has recently committed to the DRI-EAF route, with their

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189 Byrum et al., 2021, ibid.

190 Byrum et al., 2021, ibid.

191 Deason, J., M. Wei, G. Leventis, S. Smith, and L. Schwartz, 2018, *Electrification of Buildings and Industry in the United States: Drivers, Barriers, Prospects, and Policy Approaches*. Berkeley, CA: Lawrence Berkeley National Laboratory.

192 Byrum et al., 2021, ibid.

193 U.S. Energy Information Administration, 2021, 2018 *Manufacturing Energy Consumption Survey*, U.S. Energy Information Administration.

194 Mallapragada, D.S., Dvorkin, Y., Modestino, M., Esposito, D.V., Smith, W., Hodge, B-M., Harold, M.P., Donnelly, V.M., Nuz, A., Bloomquist, C., Baker, K., Grabow, L.C., Yan, Y., Rajput, N.N., Hartman, R., Biddinger, E.J., Aydil, E., and Taylor, A., 2023, Decarbonization of the chemical industry through electrification: Barriers and opportunities, *Joule*, Volume 7, Issue 1, 18 January 2023, pp. 23-41.

195 See for example, Xia, R., Overa, S., and Jiao, F., 2022, Emerging Electrochemical Processes to Decarbonize the Chemical Industry, JACS Au 2022, 2, pp. 1054−1070.; Schiffer, Z.J., and Manthiram, K., 2018, Electrification and Decarbonization of the Chemical Industry, *Joule*, Volume 1, Issue 1, 6 September 2017, pp. 10-14.

196 Mallapragrada et al., 2023, ibid.

197 Currently, coal meets 75% of the total energy demand for the iron and steel sector (International Energy Agency, 2022, Iron and Steel tracking report, September 2022).

198 McKinsey & Company, 2020, ibid.

recent $1.8 billion joint investment in a new 2.5 million tonne capacity DRI furnace, which is expected to eliminate dependence on coal and reduce carbon emissions by three million tons[199]. In general, the DRI-EAF route has 35-40% lower CO_2 emissions than conventional steelmaking, assuming the electricity comes from a renewable source[200]. Other hydrogen-based approaches are also being tested and developed by the industry (e.g., adding H_2 directly into the BF, SuSteel hydrogen plasma project, among others)[201], as well as direct reduction using molten oxide electrolysis[202]. Figure 4-3 indicates just how much RD&D remains to be completed to bring such innovations into the steel industry.

The fundamental challenge with industry electrification is the vast amount of renewable energy needed to supply the electricity required not only for direct use, but also for the generation of electrolytic hydrogen (particularly for the production of green steel). For example, switching all of Europe's steel making to hydrogen-based DRI would increase the industry's electricity demand by a factor of five, equivalent to around 18% of total current EU electricity consumption[203]. The variability of renewable electricity from wind and solar is also a major concern, although this may be ameliorated by using hydrogen as a fuel source for power generation. However, hydrogen is very difficult to store and transport, raising many of its own issues and challenges, which will be discussed further in the following section.

4.3 Hydrogen Generation and Storage Issues

Hydrogen is expected to play an important role in the transition away from fossil fuels, accounting for around 6% of cumulative emissions reductions in IEA's net zero scenario (refer to earlier Figure 4-1). Clean hydrogen can help not only to decarbonize hard to abate industries, such as iron and steel production, but also store electricity (as a clean fuel source) generated by intermittent renewables in the electricity system[204]. Many countries and sub-national jurisdictions have developed strategic plans for hydrogen going forward, including the US[205], European Union[206], Canada[207], and Ontario[208].

The main challenge with green or electrolytic hydrogen generation today is the high cost associated with its production. Most hydrogen today is made from fossil fuels, typically using natural gas in Steam

[199] ArcelloMittal Press Release, 13 October 2022 - ArcelorMittal breaks ground on first transformational low-carbon emissions steelmaking project (https://corporate.arcelormittal.com/media/press-releases/arcelormittal-breaks-ground-on-first-transformational-low-carbon-emissions-steelmaking-project).

[200] Draxler, M., Schenk, J., Burgler, T., and Sormann, A., 2020, The Steel Industry in the European Union on the Crossroad to Carbon Lean Production - Status, Initiatives and Challenges, *BHM Berg- und Hüttenmännische Monatshefte*, Volume 165, pp. 221–226.

[201] Peplow, M., 2021, Can industry decarbonize steelmaking? Major steelmakers and disruptive start-ups look to hydrogen and renewable electricity to make green steel, *Chemical & Engineering News*, Vol. 99, Issue 22. (https://cen.acs.org/environment/green-chemistry/steel-hydrogen-low-co2-startups/99/i22).

[202] Boston Metal - https://www.bostonmetal.com/green-steel-solution/.

[203] Peplow, 2021, ibid.

[204] International Energy Agency, 2022, *Hydrogen tracking report*, September 2022.

[205] U.S. Department of Energy, 2022, *DOE National Clean Hydrogen Strategy and Roadmap*, Draft - September 2022.

[206] European Commission, 2020, *A hydrogen strategy for a climate-neutral Europe*, Brussels, 8.7.2020, COM(2020) 301 final.

[207] Natural Resources Canada, 2020, *Hydrogen Strategy for Canada - Seizing the Opportunities for Hydrogen: A Call to Action*, Government of Canada, December 2020.

[208] Government of Ontario, 2022, *Ontario's Low-Carbon Hydrogen Strategy - A Path Forward*, April 2022.

Methane Reformers (SMRs), which is much cheaper than using electricity[209]. The Carbon Storage Leadership Forum estimates that green hydrogen production may not become cost competitive globally until after 2040[210]. Increased generation of green hydrogen would also require a massive increase in the amount of renewable energy[211], which will take time and has its own challenges.

In the short term, blue hydrogen (i.e., hydrogen from fossil fuels with CCS) is poised to serve as a bridge until more green hydrogen becomes available[212]. The simplest and most cost-effective production approach is to incorporate a carbon capture system to an existing SMR unit (e.g., the Shell Quest project captures CO_2 from three SMRs at its Scotford bitumen upgrader), which would require minimal changes to the existing production facility. However, much higher capture rates (> 95%) can be achieved using other technologies, such as Auto-Thermal Reforming (ATR)[213], which is the approach adopted by Air Products at its new net-zero hydrogen production facility under construction in Alberta[214].

The main challenge with blue hydrogen generation is the requirement for a suitable storage site for the captured carbon dioxide. In SW Ontario, the main hydrogen producers are located in the Sarnia area, including Air Products' Corunna Hydrogen Plant, which supplies SMR-produced grey hydrogen to the Shell, Suncor, and Imperial Oil refineries, while CF Industries and NOVA Chemicals produce their own hydrogen for ammonia and chemical manufacturing, respectively[215]. In total, over 150,000 tonnes of hydrogen is produced and used each year in the Sarnia-Lambton region[216]. Given the large concentration of CO_2 emitting industries and the potential for blue hydrogen production in the region, developing a CCS hub in the Sarnia-Lambton area would appear to have many advantages, however the region lacks favorable geological storage (see Figure 5-19 for Lambton County and section 6.2a).

The Sarnia area could also serve as a hydrogen hub, given the proximity to salt deposits for underground storage of hydrogen. Unlike other gases, hydrogen has a very low energy density and boiling point, making it challenging to store[217]. Salt caverns are ideal for underground hydrogen storage because of their low gas permeability, lack of biological activity, and favourable rheological properties for self-sealing of fractures and capacity to redistribute stress peaks[218]. Hydrogen has been stored for many decades in salt caverns along the Gulf Coast in Texas to supply and petrochemical industries in that area. The salt deposits in the Sarnia area could be used to facilitate much larger grid-scale energy

[209] Government of Ontario, 2022, ibid.

[210] CSLF, 2021, ibid.

[211] As an example, switching all current global production to electrolytic hydrogen would require around 3,600 TWh of renewable electricity, which is equivalent to the total annual electricity generation of the entire European Union (Day, P., 2022, Electrification, storage pose singular challenges for hydrogen, Reuters Events - Renewables, May 10, 2022).

[212] Global CCS Institute, 2021, *Blue Hydrogen*, April 2021.

[213] Oni, A.O., Anaya, K., Giwa, T., Di Lullo, G., and Kumar, A., 2022, Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions, *Energy Conversion and Management*, Volume 254, 15 February 2022, 115245.

[214] Air Products - https://www.airproducts.com/campaigns/alberta-net-zero-hydrogen-complex.

[215] GHD, 2022, *Ontario's Hydrogen Hub in Sarnia-Lambton - Strategic Plan*, Report for the Sarnia-Lambton Economic Partnership, December 22, 2022.

[216] GHD, 2022, ibid.

[217] International Energy Agency, 2022, *Global Hydrogen Review* 2022.

[218] GHD, 2022, ibid.; see also the SHASTA report for an excellent review of issues related to underground storage of hydrogen (SHASTA, 2022, *Subsurface Hydrogen and Natural Gas Storage: State of Knowledge and Research Recommendations Report*, SHASTA: *Subsurface Hydrogen Assessment, Storage, and Technology Acceleration Project*, April 2022).

storage and to support grid resiliency by converting excess power on the grid into hydrogen (using electrolyzers), which could then be converted back into electricity during periods of high demand (e.g., daily or seasonally).

Bruce Power is also looking into the potential of producing pink hydrogen from excess energy (including steam) at its nuclear station in Tiverton, Ontario[219], while Atura Power announced the construction of a green hydrogen pilot production facility at Niagara Falls for grid balancing and off-peak hydrogen production for the merchant market, as well as blending with natural gas in natural gas combustion turbines[220].

In addition to the storage issues, the other major challenge for increased hydrogen generation and use is transportation. While hydrogen can blend in existing natural gas pipelines in small amounts[221], those pipelines are not adapted for hydrogen delivery under high pressure, resulting in risk of leakage and metal embrittlement[222]. Therefore, a mass exchange of hydrogen in place of natural gas would require the costly construction of new pipeline infrastructure, or at minimum, expensive retrofitting of existing pipelines[223].

Given the low cost of natural gas in Ontario and other economic issues, the adoption of hydrogen as a clean fuel source is expected to progress slowly over time. The report for the Sarnia-Lambton Economic Partnership estimates the demand for low-carbon hydrogen to range from 25,000 to 60,000 tonnes per year by 2030 (compare this with the 150,000 tonnes of hydrogen produced and used annually in the area today)[224]. Besides the cost issue, the technologies needed by the industry sector to switch to hydrogen-based fuels are still not completely mature, as shown in Figure 4-3, and will need to undergo further development and testing to reach commercial readiness levels. In the meantime, however, the current production of grey hydrogen using SMRs could be converted to blue hydrogen immediately, by adding CCS to existing hydrogen production facilities. Of course, this would require resolving the outstanding economic, regulatory and technological barriers and uncertainties impacting the development of CCS in SW Ontario.

[219] Bruce Power, 2022-04-07 Press Release - https://www.brucepower.com/2022/04/07/bruce-power-to-explore-feasibility-of-using-excess-energy-for-hydrogen-production/.
[220] Atura Power, April 7, 2022 News Release - https://aturapower.com/news/atura-power-selects-niagara-for-the-niagara-hydrogen-centre/.
[221] Enbridge Gas and Cummins are conducting a pilot project in Markham to inject hydrogen into natural gas pipelines, adding up to 2 per cent hydrogen by volume into the gas stream for 3,600 customers (Enbridge Gas, January 13, 2022 Blog - https://www.enbridge.com/stories/2022/january/hydrogen-blending-project-enbridge-gas-cummins-operational-markham-ontario).
[222] Liguori, S., K. Kian, N. Buggy, B. Anzelmo, and J. Wilcox, 2020, Opportunities and Challenges of Low-Carbon Hydrogen via Metallic Membranes, *Progress in Energy and Combustion Science*, 80.
[223] IEA Global Hydrogen Review 2022, ibid.
[224] GHD, 2022, ibid.

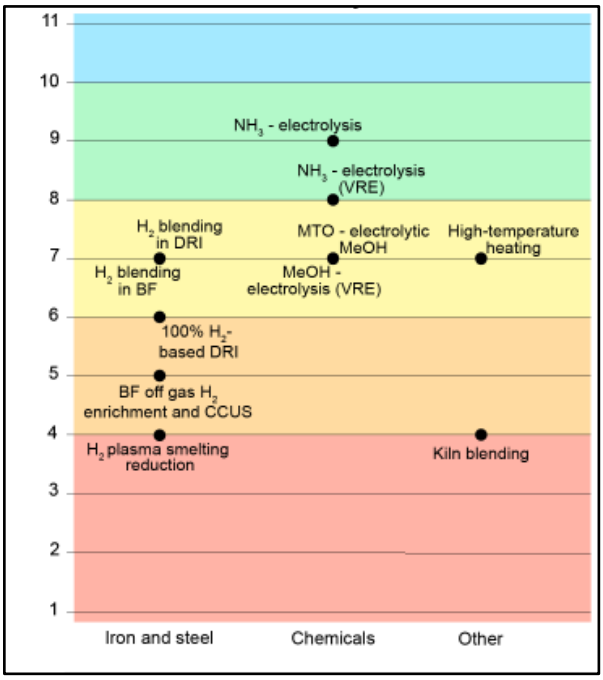

FIGURE 4-3 TECHNOLOGY READINESS LEVELS OF HYDROGEN END-USES BY INDUSTRY SECTOR (COPIED FROM IEA GLOBAL HYDROGEN REVIEW 2022 PAGE 227 – NOTE IEA USES ADDITIONAL TRL 10 AND TRL 11 TO REFLECT FURTHER COMMERCIAL MATURITY).

5 EVALUATING AND SELECTING CO_2 STORAGE RESERVOIRS IN SW ONTARIO

A common theme in each of the CCS workshops held in Waterloo during late 2022 was that if the CO_2 storage capacity of Ontario's geological reservoirs was well characterized and the results well understood, then commercial decisions, i.e., FIDs, could be made regarding emissions reduction by 2030. We have urged in **Recommendation 1**, that 10 MT/yr of geological storage capacity be proven as available by 2025, implying that drilling and testing potential reservoirs occurs actively from 2023 onwards at several promising sites with SW Ontario that we discuss later in this section. One implication of this 2030 deadline is that by 2025 the regulatory environment under which CO_2 pipelines are built is well established so that the 4-year pipeline-construction timeline is met.

Unfortunately, there has been little progress towards developing 10 MT/yr of potential CO_2 storage capacity beneath SW Ontario. Without numerous boreholes completed within the potential CO_2 storage reservoirs and then characterized by in-situ hydraulic testing, it is impossible to provide reliable estimates of storage capacity at any one site. The preliminary estimates provided by Shafeen and others at the University of Waterloo[225] in 2004 were subsequently used in the "Carter report" [226] in 2007. These estimates are re-examined below (section 5.4) in the light of the past 20 years of experience in geological storage of CO_2.

However, following the promising start to addressing provincial geological storage of the Carter report, the Government of Ontario lost interest in the topic until it called for recommendations to develop a policy framework in January 2022[227]. Thus 15 years were lost while Alberta and Saskatchewan made such progress that Boundary Dam 3 and Quest are now considered worldwide as successful pioneers of CCS technology and to have "*demonstrated the diversity and potential of CCS*"[228].

In this section we consider the criteria for geological CO_2 storage, the principal mechanisms involved in the migration and fate of CO_2 in reservoirs deemed suitable for storage, the availability of such reservoirs within Ontario's sedimentary bedrock, and what RD&D needs should be conducted in the near term to determine CO_2 injection potential, confinement, and storage capacity.

5.1 Criteria for Choice of Reservoirs

In 2009 the IEA Greenhouse Gas R&D Programme[229] commissioned the Alberta Research Council to conduct a review of storage site selection criteria and site characterisation methods. Although no geological CO_2 storage project had been completed in Alberta at that time of writing, the authors were

[225] Shafeen, A., Croiset, E., Douglas, P.L. and Chatzis, I., 2004. CO2 sequestration in Ontario, Canada. Part I: storage evaluation of potential reservoirs. *Energy Conversion and Management*, 45(17), pp.2645-2659.
[226] Carter, T., Gunter, W., Lazorek, M. and Craig, R., 2007. *Geological Sequestration of Carbon Dioxide: a Technology Review and analysis of opportunities in Ontario*. Climate Change Research Report-Ontario Forest Research Institute, (CCRR-07), Ministry of Natural Resources, Sault Ste. Marie, Ontario.
[227] https://ero.ontario.ca/notice/019-4770#decision-details
[228] Herzog, H.J., 2018. *Carbon Capture*. MIT Press, p.106.
[229] IEA GHG, 2009. *CCS Site Characterization Criteria.* Report 2009-10. IEA GHG R&D Programme, Cheltenham, UK.

able to draw upon the knowledge gained from the injection of acid-gas into deep saline aquifers[230]. The ARC review identified three basic principles that the selected reservoir must display:

(i) sufficient porosity and thickness to create the storage capacity necessary.
(ii) sufficient permeability to allow injection; and
(iii) the presence of at least one (but preferably multiple) confining stratum to prevent escape and migration of the injected CO_2.

These basic principles were adopted in Canadian Standards Association Standard CSA Z741-12[231], which was written in part by some who had been involved in the development of CCS projects in western Canada. The CSA standard provides the basic principles of safe geological CO_2 storage. Figure 5-1 presents the critical elements of safe storage:

1. A source of CO_2 emissions, shown here as an industrial plant, that has a CO_2 capture system.
2. Pipeline transmission of CO_2 to injection wells.
3. A saline aquifer-caprock seal system, in which CO_2 is to be stored and contained.
4. Groundwater and natural gas resources should be unaffected by the injection of CO_2 below.

The aquifer-caprock pair is often referred to as *the storage system* and is subject to detailed testing. It is also possible to store CO_2 within a depleted oil or gas reservoir, although this is not shown here.

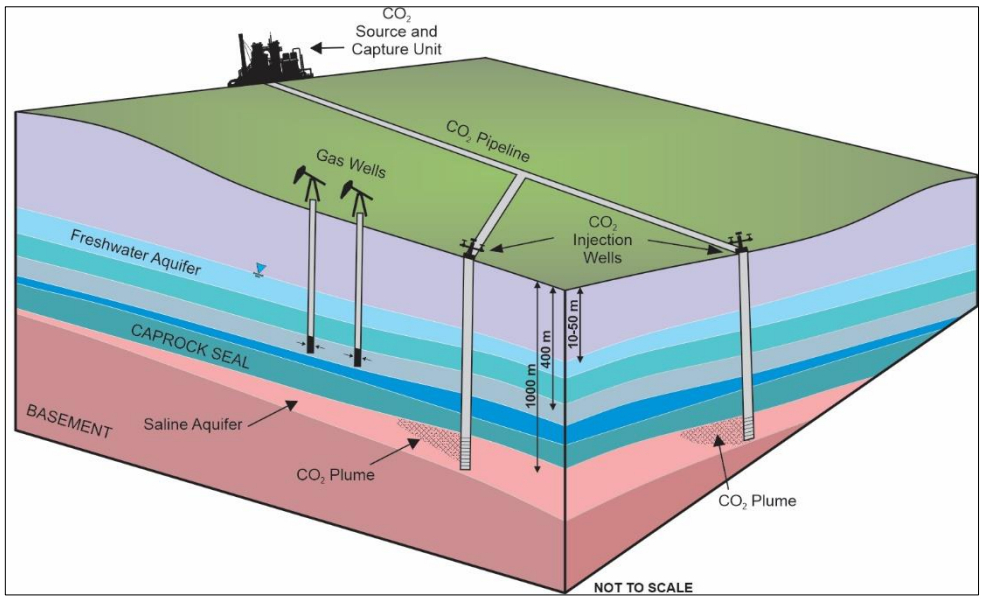

FIGURE 5-1 CONCEPTUAL MODEL OF A CCS HUB

[230] Bachu, S. and Gunter, W.D., 2005. Overview of acid-gas injection operations in western Canada. In *Greenhouse Gas Control Technologies* 7: 443-448. Elsevier Science Ltd.
[231] CSA Z741-12, *Geological Storage of Carbon Dioxide.* Canadian Standards Association, Mississauga. Reaffirmed 2022.

This CSA Standard has undergone at least two reviews and reaffirmations since it was originally published in 2012. Its primary application is to saline aquifers and depleted oil and gas reservoirs, both of which will be permitted by the Government of Ontario to store or otherwise receive CO_2.

Section 5 of the CSA Standard addresses site screening, selection, and characterization. It begins by reiterating the three ARC principles but adds a fourth: *that site characterization and assessment at any potential site does not jeopardize other resources, e.g., potable groundwater, the environment and public health, and project developers, owners, and operators*. The CSA Standard stresses that site characterization is an iterative process that proceeds as the site is developed and continues during its operation.

5.2 The Injection, Migration and Fate of CO_2 in the Subsurface

To minimize the pore volume required for its storage, CO_2 is injected into the subsurface as a dense or supercritical fluid (~700 kg/m^3). Compared with its density in the atmosphere, this produces a density just 0.27% of that at standard temperatures and pressures. Injection into the storage reservoir – here assumed to be a saline sandstone aquifer – causes thermal effects in the near-wellbore rock and buoyant flow of the CO_2 upwards towards the confining caprock. In the case of a depleted oil or gas reservoir, the depleted pressure of the reservoir will modify this behaviour.

Once injected, the CO_2 plume migrates buoyantly driven by pressure gradients and buoyancy. During injection, CO_2 movement will likely be driven predominantly by the injection pressure gradient. After the injection phase, buoyancy becomes more important and CO_2 will tend to move along the lower contact of the caprock (or along other internal aquitards within the reservoir) with its behaviour affected by capillary processes and viscous and buoyancy dynamics[232,233,234]. Thereafter, various trapping mechanisms determine the fate of the injected CO_2 plume. What has not been sufficiently appreciated in the past is the degree to which the initial and injection-modified pressures of the reservoir constrain the geological storage of CO_2.

5.2.1 CO_2 Injection into a Saline Aquifer

Figure 5-2 illustrates the processes occurring in the vicinity of an injection well following CO_2 injection. The injected dense- or supercritical-phase CO_2 causes a drying out of the brine-filled zone of the aquifer adjacent to the wellbore as well as brine displacement. Where large temperature contrasts between injected CO_2 and the storage reservoir exist, cold CO_2 can also cause fracturing of the rock adjacent to the injection well due to localized thermal contraction of the reservoir rock. This is believed to have happened at Aquistore.

[232] Ringrose, P., 2020. *How to store CO2 underground: Insights from early-mover CCS projects* Berlin/Heidelberg, Germany: Springer International Publishing.
[233] Smit, B., Reimer, J.A., Oldenburg, C.M. and Bourg, I.C., 2014. *Introduction to carbon capture and sequestration* (Vol. 1). Imperial College Press, London UK.
[234] Woods, A.W., 2015. *Flow in Porous Rocks*. Cambridge University Press. Cambridge, UK.

Figure 5-2 shows the buoyant CO_2 rising in the near-well region to the base of the caprock or other intermediate confining unit and there migrates as a two-phase CO_2-brine fluid along the base of the confining caprock. This closed stratigraphic trap is likely to be the principal containment architecture of geological CO_2 storage beneath SW Ontario, in which case the CO_2 is unable to penetrate the pores of the caprock because of capillary blockage.

When a fluid of a different density and viscosity to that of the host fluid is injected into a porous and permeably aquifer, as is the case with CO_2 injection into a brine-filled sandstone, the behaviour of the injected CO_2 is governed by processes that depend on the capillary properties of the sandstone, relative permeability of the separate phases, buoyancy forces (i.e., gravitational), and the viscosity contrast between the injected CO_2 and the formation brine. These processes are discussed in the context of an injected CO_2 plume by Ringrose[235] and Woods[236].

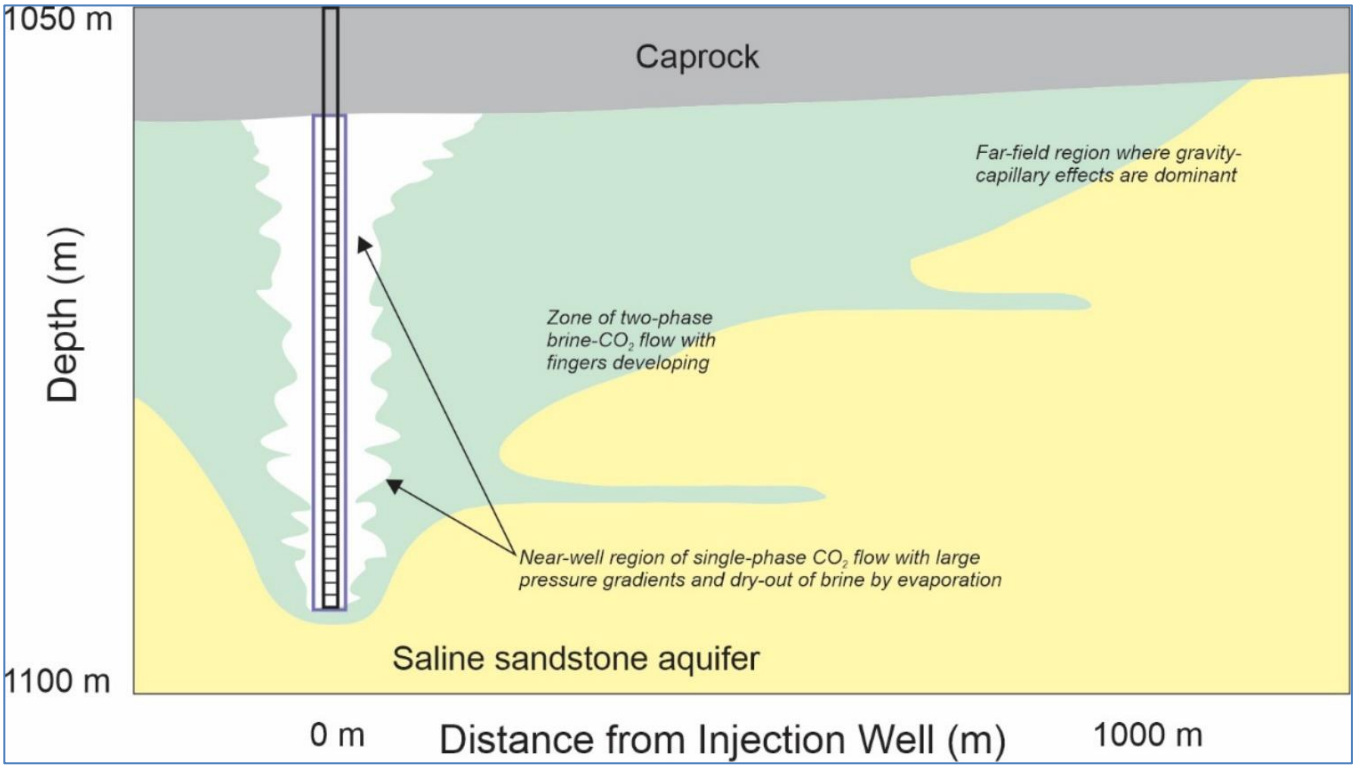

FIGURE 5-2 SCHEMATIC OF CO_2 MIGRATION IN THE VICINITY OF AN INJECTION WELL[237]

[235] Ringrose, P., 2020. *How to store CO_2 underground: Insights from early-mover CCS projects* Berlin/Heidelberg, Germany: Springer International Publishing.

[236] Woods, A.W., 2015. *Flow in Porous Rocks*. Cambridge University Press. Cambridge, UK

[237] Modified after Oldenburg, C.M., Mukhopadhyay, S. and Cihan, A., 2016. On the use of Darcy's law and invasion-percolation approaches for modeling large-scale geologic carbon sequestration. *Greenhouse Gases: Science and Technology*, *6*(1), pp.19-33.

5.2.2 Trapping Mechanisms

The conceptual model of the trapping mechanisms of CO_2 following injection into the storage reservoir are shown schematically in Figure 5-2. Each geological reservoir stores CO_2 differently over time depending on its constituent physical-chemical properties and sedimentary architecture. While structural and stratigraphic trapping is the primary mechanism of storage – at least in the early years following injection – the secondary mechanisms vary as is illustrated in Figure 5-3.

In *closed structural* (e.g., anticline) or *stratigraphic traps* (e.g., a pinchout of a saline aquifer as shown in Figure 5-1), trapping by dissolution and capillary processes is initially small, as shown in Figure 5-2. Most of the injected CO_2 remains as a separate phase, that is, either as liquid, gas, or dense (supercritical) phase, as has been observed in early CO_2 storage projects beneath the North Sea in Europe[238].

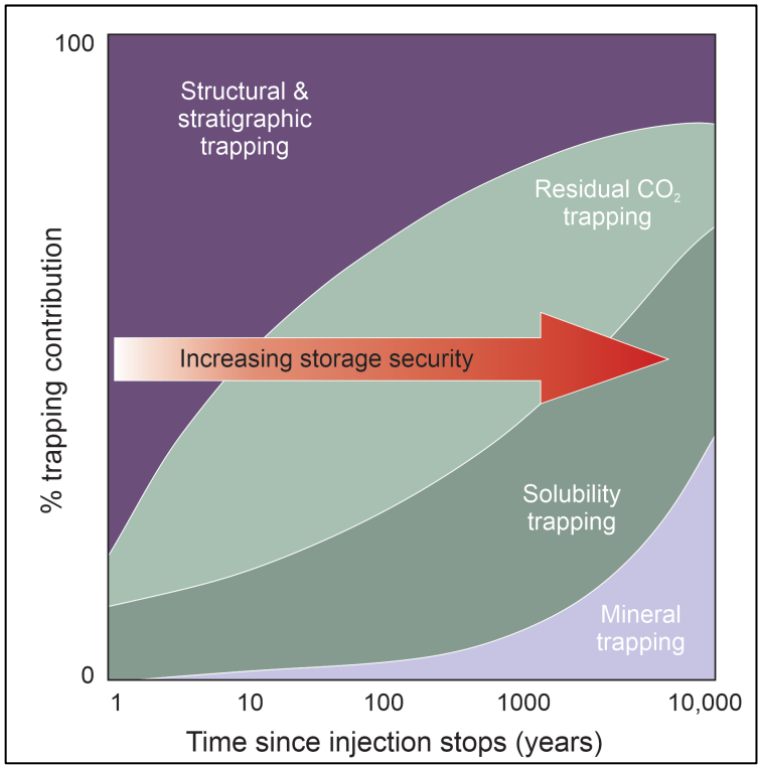

FIGURE 5-3 GENERAL EVOLUTION OF TRAPPING PROCESSES WITH TIME SINCE INJECTION[239]

Generally, it is to be expected that in saline aquifers, in which migration is occurring in a generally horizontal direction and confined above by the caprock, the aquifer forms a '*hydrodynamic trap*'.

[238] Ringrose, P.S., Furre, A.K., Gilfillan, S.M., Krevor, S., Landrø, M., Leslie, R., Meckel, T., Nazarian, B. and Zahid, A., 2021. Storage of carbon dioxide in saline aquifers: physicochemical processes, key constraints, and scale-up potential. *Annual Review of Chemical and Biomolecular Engineering*, *12*, pp.471-494.
[239] Benson, S.M. and Cole, D.R., 2008. CO_2 sequestration in deep sedimentary formations. *Elements*, *4*(5), pp.325-331.

- In a hydrodynamic trap, the more extensive residence of the CO_2 and greater contact with rock matrix of the saline aquifer allow much greater *residual-phase or capillary trapping*. In this case, the non-wetting fluid (CO_2) is trapped in the large pores of the rock while the wetting phase (brine) occupies the small pores[240]. However, most of the trapping is still due to the confined nature of the structural or stratigraphic trap.

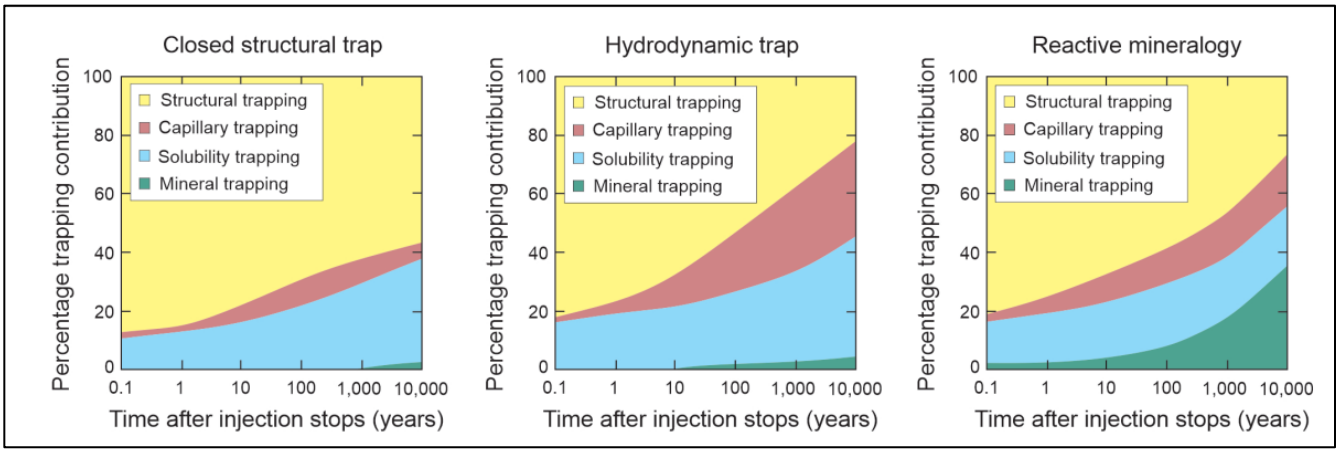

FIGURE 5-4 SECONDARY TRAPPING MECHANISMS IN SALINE SANDSTONES[241]

In contrast to structural, stratigraphic, or capillary trapping, the other trapping mechanisms involve a change of phase of the CO_2 in that it must first dissolve and thereby become available for 'trapping' as a solute and then, perhaps, be converted to a mineral phase. These require longer residence times to become important.

- *Solubility trapping*, the process by which the CO_2 dissolves in the brine to form carbonic acid can be substantial. Solubility trapping in a hydrodynamic trap (middle box of Figure 5-4) is more important than in a closed structural or stratigraphic trap because of the greater contact between CO_2 and the formation brine. If carbonate minerals are present together with dense-phase CO_2, the brine will be buffered at ~ pH 5.
- *Mineral trapping*, involving CO_2 mineralization as a carbonate mineral, may occur where reactive minerals are present. In a typical saline sandstone these reactive minerals are likely to be feldspars that will weather into clays and release cations that may form carbonate minerals with the carbonate released by solubility trapping.

5.2.3 Migration Behaviour

In the years following the 2004 Shafeen study[242] it became apparent that the ability of CO_2 to access much of the pore volume within a permeable reservoir was even more limited than Shafeen had considered. This was well known to those working in enhanced oil recovery (EOR) where injected fluids

[240] See Smit, et al., 2014. ibid.
[241] From National Academy of Sciences, Engineering and Medicine, 2018. *Geological Capture and Sequestration of Carbon: Proceedings of a Workshop – in Brief.* Washington D.C.: The National Academies Press.
[242] Shafeen, A. et al., 2004. ibid.

would try to access parts of a reservoir containing residual oil[243] that had been left behind during primary production. Surfactants and polymer floods would try to recover this stranded oil without bypassing it.

The same complicating physical-chemical processes affecting EOR floods control how much CO_2 is trapped within a saline aquifer following injection. These processes result in very low storage efficiencies, which is defined as the fraction of pore space occupied by the injected CO_2. For example, despite very favourable reservoir properties, the Sleipner project in the Norwegian North Sea had achieved a storage efficiency of only 5.2% after 17 years of CO_2 injection and 14.7 MT CO_2 injected[244]. Various research projects are underway to determine how to maximize the storage efficiencies of saline aquifers. Research includes both brine extraction downgradient of injection and polymer flooding the injected CO_2 to minimize permeability channeling.

The complicating processes producing low storage efficiencies are a result of the gravitational, viscous, permeability, and capillary phenomena mentioned earlier. There are four principal processes active that reduce the storage efficiency:

1. *Gravitational segregation:* the dense CO_2 phase is buoyant as shown in Figure 5-2 where the injected single-phase CO_2 plume rises adjacent to the well and a two-phase region develops down the pressure gradient.
2. *Permeability heterogeneity:* channeling due to more permeable strata within an otherwise lower permeability rock unit. See Figure 5-5.
3. *Capillary blockage:* interfacial tension of CO_2 and brine impedes entry of CO_2 into small pores. See Figure 5-6.
4. *Viscous fingering:* the low viscosity of CO_2 relative to brine causes frontal instabilities leading to fingering of CO_2[245] within the brine. See Figure 5-7. This differs from the effects shown in Figure 5-5 where permeable channels promote fingering, whereas viscous instabilities can occur in entirely homogeneous and isotropic porous media.

[243] Lake, L.W., 1989. *Enhanced Oil Recovery.* Prentice-Hall, Englewood Cliffs, New Jersey, USA.
[244] Ringrose, P., 2020. Ibid.
[245] Woods, 2015. Ibid.

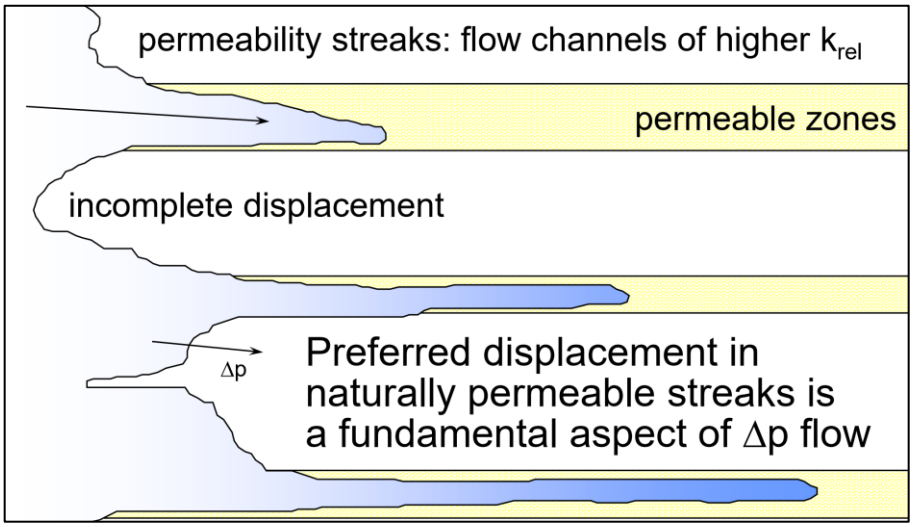

FIGURE 5-5 PERMEABILITY HETEROGENEITY CAUSING FINGERING[246]

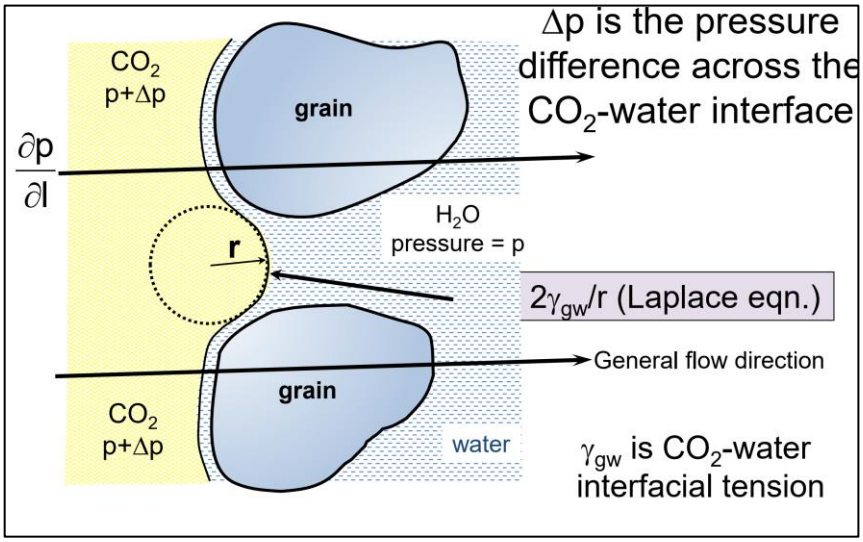

FIGURE 5-6 CAPILLARY BLOCKAGE[247]

[246] Presentation by Maurice Dusseault, CCS Laws & Regulations Workshop, Waterloo, Ontario, 13 October 2022.
[247] Presentation by Maurice Dusseault, CCS Visioning Workshop, Waterloo, Ontario, 27 October 2021.

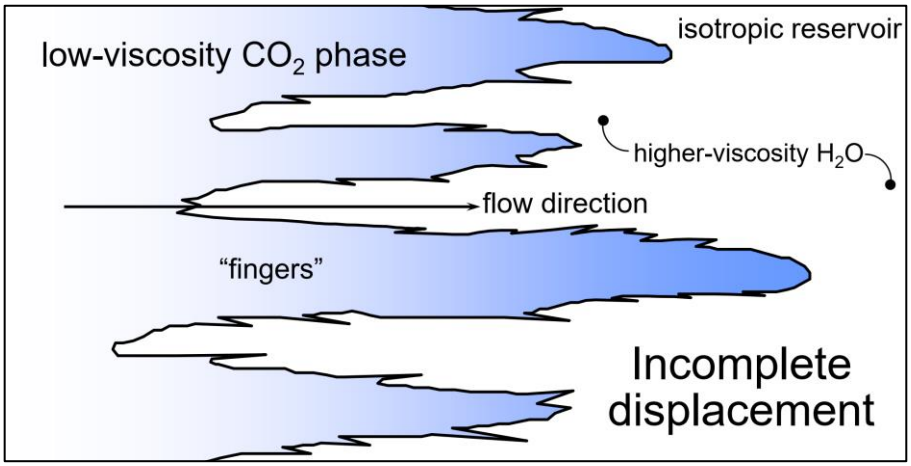

FIGURE 5-7 VISCOUS FINGERING[248]

5.2.4 Pressurization of the Aquifer

A constraint on the CO_2 injection pressure applied to a geological storage reservoir is the pressure buildup within that reservoir and its potential effect on the caprock seal containing the CO_2. Furthermore, from a risk management perspective, a larger pressurized reservoir volume means an increased probability of intercepting one or more poorly abandoned wells, causing a brine leak.

This pressure buildup reflects the characteristics of the receiving aquifer: i.e., its permeability and its initial or 'discovery' pressure, the composition of the host fluid and its geographical boundaries. Typical injection operations for gas storage reservoirs in Ontario limit the injection pressure to 80% of the fracture pressure of the caprock to avoid caprock damage. This, of course, assumes that the caprock has been found to be free of through-going faults that would allow fluid leakage.

A principal objective of in-situ testing of a potential CO_2 storage reservoir is to obtain the maximum injection pressure and injectivity under conditions that would be consistent with maintaining caprock integrity. Findings from such testing should also allow the variation in pressure with distance from the injector to be computed by numerical simulation in order to avoid hydraulic interference with any adjacent injectors caused by brine displacement and compression. Figure 5-8 indicates how the pressure increase dissipates over distance. Therefore, an injection test using brine should allow the Δp at a radial distance, r, to be calculated within the formation.

[248] Presentation by Maurice Dusseault, CCS Visioning Workshop, Waterloo, Ontario, 27 October 2021.

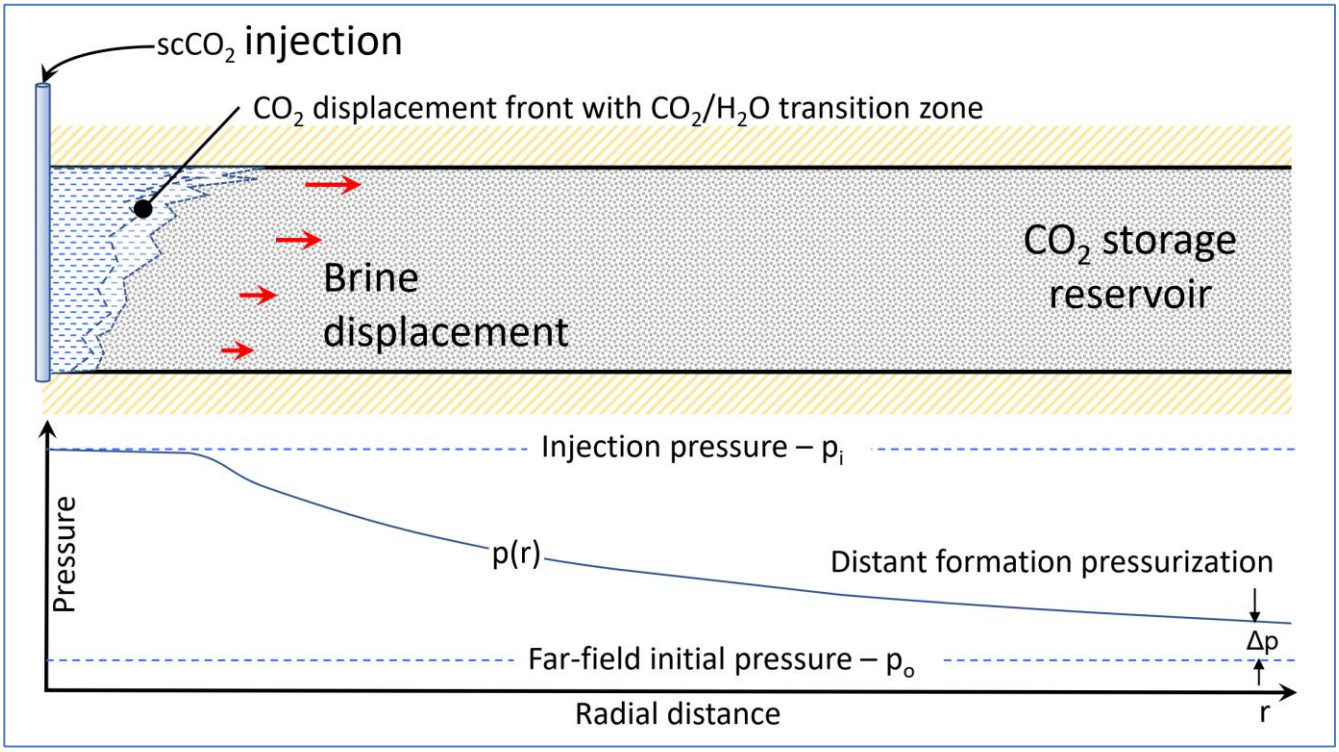

FIGURE 5-8 PRESSURE VARIATION WITHIN THE CO_2 STORAGE RESERVOIR[249]

A second constraint is the need to prevent significant seismic instabilities, particularly in the igneous and metamorphic rocks of the underlying Precambrian Shield basement. The existence of fault structures within the basement rocks may be poorly understood in areas where geological storage is planned, although faults may be well known in the overlying Paleozoic sedimentary rocks from extensive oil and gas drilling. An increase in fluid pressure within the fault zone from injection operations may cause a critically-stressed fault to slip and create a felt earthquake, i.e., one of sufficient magnitude to be perceptible.

Geological storage projects like Quest and Aquistore have always operated in saline aquifers in which no other nearby injection operations were occurring. Consequently, they could proceed without consideration of hydraulic interference by other injection operations. Furthermore, the numerical models used to simulate the allowed pressure buildup in the receiving aquifers had only the concerns of caprock integrity and seismic stability of the basement in mind.

Figure 5-9 illustrates how pressure buildup (Δp) develops over 20 years in a regional sandstone aquifer that is undergoing injection of dense CO_2 from a single injection well that fully penetrates the sandstone aquifer. All other parameters – permeability, porosity, aquifer thickness, etc. – being equal, it is the bulk

[249] Presentation by Maurice Dusseault, *Accessing Rock Mass Pore Volume.*

compressibility of the aquifer that is the critical parameter, which is defined as the ratio of a fractional volume change of the reservoir rock to a pressure change of the pore filling fluid(s)[250].

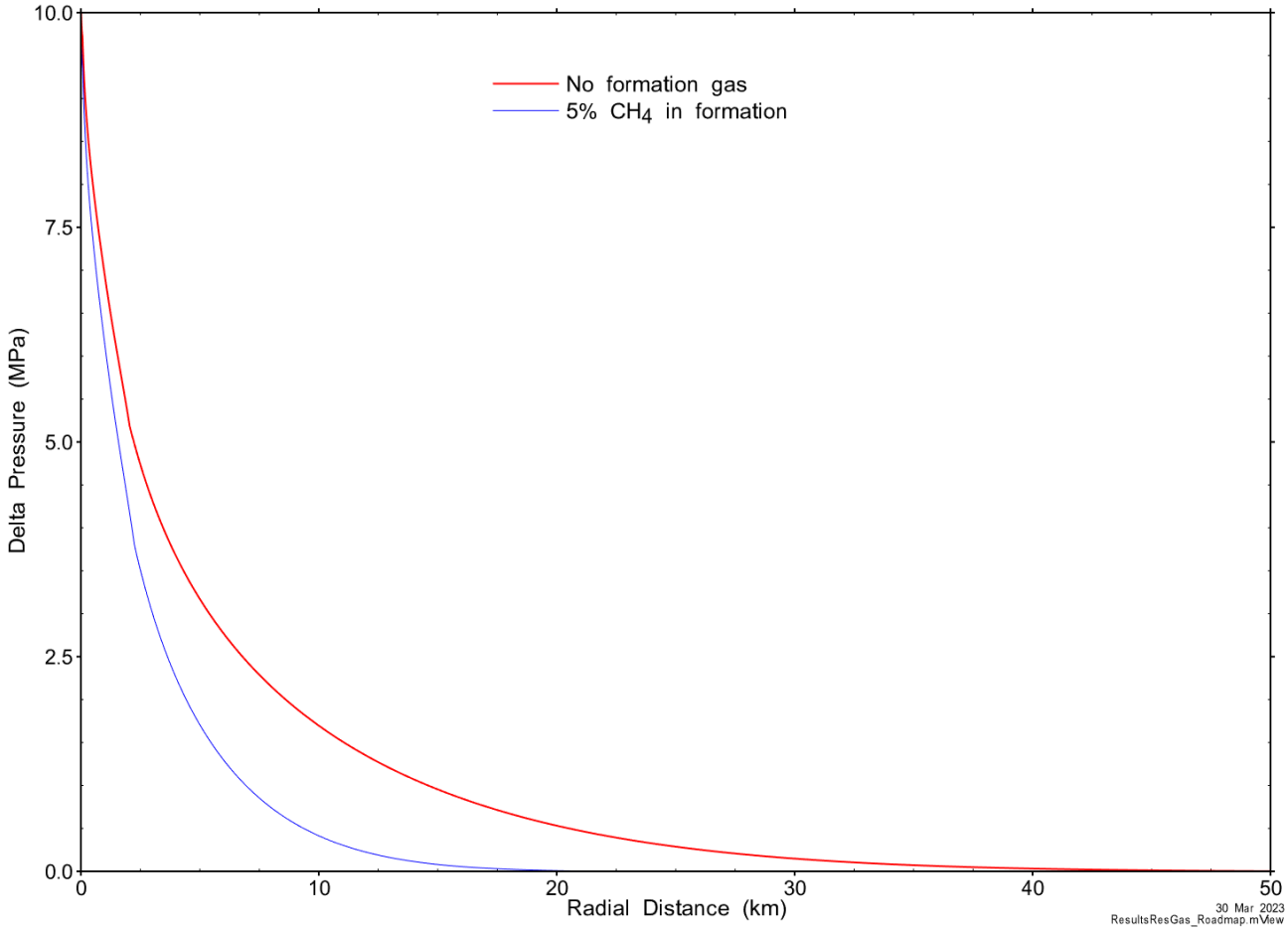

FIGURE 5-9 LATERAL EXTENT OF A PRESSURE DOME WITHIN A HORIZONTAL SANDSTONE AQUIFER[251]

This pressurized zone may be thought of as a virtual pressure dome that will apply variable fluid pressure with distance from the injector. The pressure increase will be transmitted to the basal surface of the caprock and upper surface of the basement, therefore numerical simulations such as these are important in constraining injection rates. Because the sand grains of the sandstone and the brine within its pores are both essentially incompressible, the compressibility relates to the change in the granular skeleton of the aquifer.

If the host fluid contains a residual gas saturation, the extent of the pressure dome is reduced as is shown in Figure 5-9. What is noteworthy is how the presence of minor amounts of residual gas in the sandstone acts to minimize the area affected by a substantial pressure increase. It should be apparent

[250] Wang, H.F., 2000. *Theory of Linear Poroelasticity with Applications to Geomechanics and Hydrogeology.* Princeton University Press, Princeton, New Jersey, USA.
[251] Figure prepared by Robert Walsh, Geofirma Engineering Ltd., Ottawa using TOUGH3/ECO2M for this Road Map.

how injection wells might interfere with one another over large distances. It is interesting then that Alberta Innovates has recently concluded that, with additional injection-well hubs under development in the basal Cambrian sandstone of the Edmonton area, a "*large-scale regional dynamic reservoir pressure model of proposed hub interactions*" is now required[252]. Samaroo et al.[253] has evaluated just such dynamics.

Field measurement of compressibility is needed to account for the potential presence of residual gases that will affect the performance of the injection well and the extent of the pressure dome. In standard hydrogeological practice, a two-well hydraulic test is conducted yielding both formation transmissivity and storativity, which is related to compressibility. The two wells must be close enough together that the hydraulic signal at one well is clearly measurable at the other. This information will allow simulations to determine how the pressure buildup (Δp) could be managed by employing a network of CO_2 injection wells coupled with brine extraction wells to facilitate the injection operations. Such work on reservoir engineering has been undertaken in Alberta[254] and the US[255,256].

In a saline sandstone aquifer that is to receive CO_2 injection, this proximity of the two wells raises issues concerning the potential for one of the wells to leak should the other be used as an injection well. It may be necessary to plug and abandon one of the wells to prevent such an occurrence. The potential pressurization of remote, poorly plugged, and abandoned oil and gas wells within the same formation should also be considered. This may cause fluid discharge to the ground surface or intermediate zone formations. The design of in-situ hydraulic testing is a topic that deserves further investigation by the CCS community so that accepted methods of practice are made clear.

In summary, large Δp arising from CO_2 injection can have serious consequences including:

1. Increased risk of induced seismicity.
2. Changes in stresses (reduction) in adjacent formations.
3. Potential impairment in caprock integrity.
4. Potential pressurization of remote, poorly plugged and abandoned oil and gas wells.

The potential for such consequences must be carefully evaluated by in-situ testing beforehand and the consequences fully considered.

[252] Zhou, J., et al., 2022. *Carbon Capture, Utilization, and Storage (CCUS): Technology Innovation to Accelerate Broad Deployment in Alberta.* Alberta Innovates, Edmonton, Alberta.
[253] Samaroo, M., Chalaturnyk, R. and Dusseault, M., 2023. Estimating Sustainable Long-Term Fluid Disposal Rates in the Alberta Basin. *Energies*, *16*(6), p.2532.
[254] Leonenko, Y. and Keith, D.W., 2008. Reservoir engineering to accelerate the dissolution of CO2 stored in aquifers. *Environmental Science & Technology*, *42*(8), pp.2742-2747.
[255] Buscheck, T.A., Sun, Y., Chen, M., Hao, Y., Wolery, T.J., Bourcier, W.L., Court, B., Celia, M.A., Friedmann, S.J. and Aines, R.D., 2012. Active CO2 reservoir management for carbon storage: Analysis of operational strategies to relieve pressure buildup and improve injectivity. *International Journal of Greenhouse Gas Control*, *6*, pp.230-245.
[256] Dalkhaa, C., Jiang, T., Burton-Kelly, M.E., Scharenberg, M., Smith, V., Walker, J.L., Duguid, A., Heinrichs, M.R., Bosshart, N.W. and Sorensen, J.A., 2022. A simulation study of carbon storage with active reservoir management. *Greenhouse Gases: Science and Technology*, *12*(1), pp.4-23.

5.3 Saline Aquifers as Storage Reservoirs: the Cambrian of SW Ontario

Sandstone aquifers have been the preferred choice of saline formations for dedicated geological CO_2 storage in the North Sea (Sleipner), US Mid-West (Illinois Basin Decatur Project) and western Canada (Aquistore and Quest)[257]. In these cases, they are sufficiently thick and extensive that many of the sandstone layers within the Cambrian formation (Fm.) possess sufficient porosity and permeability for CO_2 storage. The basal Cambrian sandstone of North America overlies the Precambrian basement and is itself overlain by thick impermeable Ordovician age caprocks, as shown in Figure 5-10, which is based on borehole T011132 in Haldimand County.

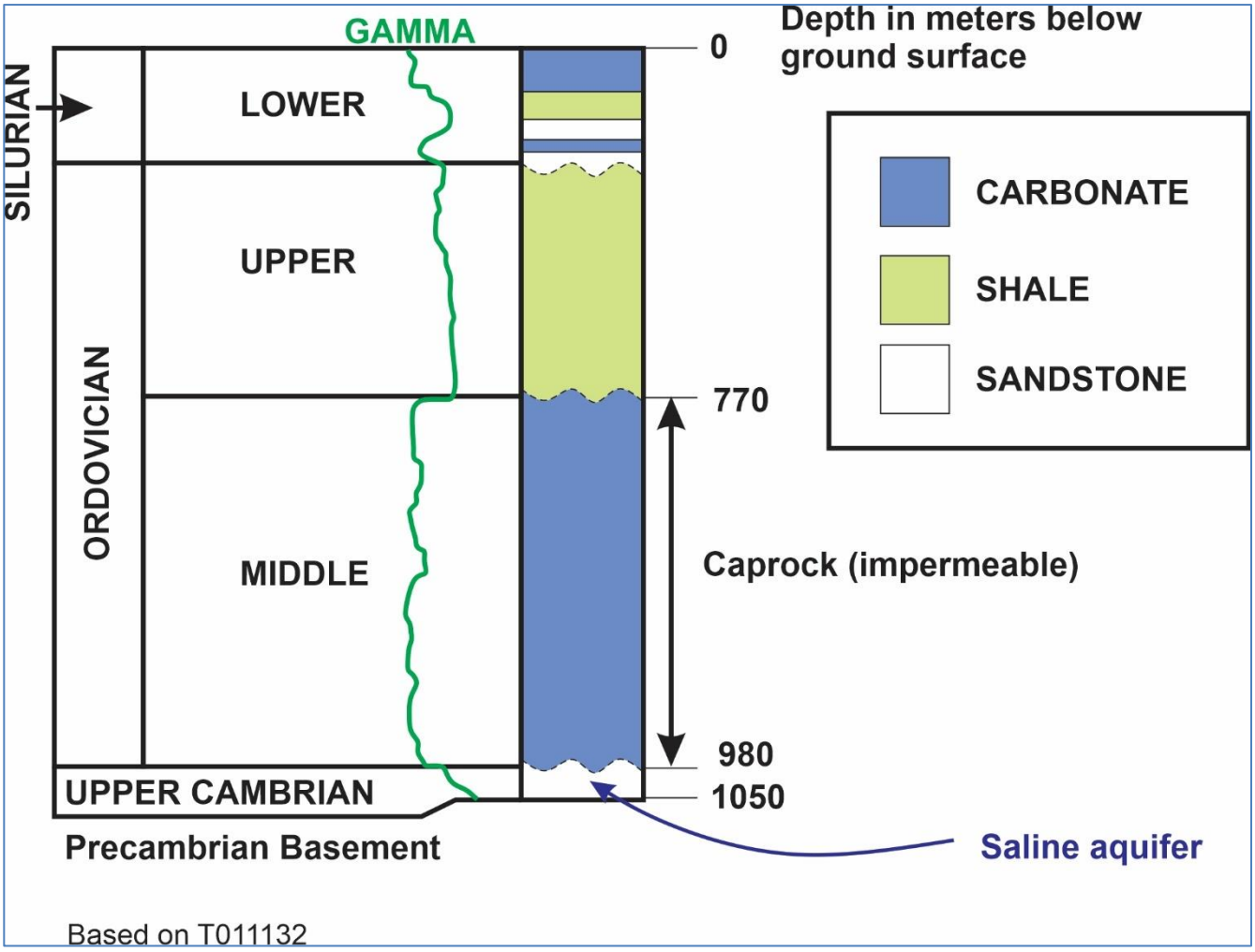

FIGURE 5-10 SCHEMATIC OF SALINE CAMBRIAN AQUIFER AND ORDOVICIAN CAPROCK

The sedimentary depositional environment of the Cambrian sandstone was that of a shallow-marine, tidal environment in which several lithofacies or depositional environments with characteristic textural compositions existed: "*tide-dominated bay margin, proximal bay and distal bay sedimentary*

[257] See Davis, T.L., Landrø, M. and Wilson, M. eds., 2019. *Geophysics and Geosequestration*. Cambridge University Press for reviews of geophysical appraisal of CO_2 migration at Sleipner, Decatur IL and Aquistore SK.

environments of deposition.[258]" In western Canada, this sandstone is referred to as the basal Cambrian sands (Alberta) or the Deadwood Fm. (Southern Saskatchewan). In the US Mid-West, it is known as the Mt. Simon, when it exists as the basal sandstone of the Cambrian Fm., and as the Potsdam sandstone in New York, eastern Ontario, and Québec[259]. Figure 5-11 shows an exposure of the Potsdam Fm. in Ontario lying unconformably on the Precambrian basement.

FIGURE 5-11 THE CAMBRIAN POTSDAM FM., NEAR KINGSTON, ONTARIO, SHOWING THE UNCONFORMITY WITH THE PRECAMBRIAN BELOW[260].

Figure 5-12 shows the Cambrian Fm. to be over 800 m below ground surface (bgs) and of variable thickness across most of SW Ontario. Figure 5-13, an isopach map, is based on the contouring of well logs for the Cambrian Fm. and the overlying Shadow Lake Fm., which contains the Innerkip and Gobles hydrocarbon reservoirs between London and Kitchener that were originally thought to be Cambrian reservoirs[261]. Figure 5-13 shows that the bedrock beneath Lake Huron is undrilled, while that beneath the Canadian part of Lake Erie had ~550 producing gas wells in 2010[262], with a few penetrating the Cambrian Fm.

[258] Halladay, A., 2018. The Quest for Less CO_2: The Quest Carbon Capture and Storage Operation. *Reservoir* 2: 13-15. Published by the Canadian Society of Petroleum Geologists.
[259] Konstantinovskaya, E., Rivero, J.A., Vallega, V., Brodylo, J. and Coldham, P., 2023. 3D reservoir simulation of CO2 injection in a deep saline aquifer of the Lower Paleozoic Potsdam Sandstone of the St Lawrence Platform, Gentilly Block, Quebec. *Geoenergy*, *1*(1), pp.geoenergy2022-001.
[260] Photo by Bruce Hart, Western University.
[261] Dorland, M., Colquhoun, I., Carter, T.R., Phillips, A., Fortner, L., Clark, J., and Hamilton, D., 2016. Ontario Oil and Gas: 2. Cambrian and Ordovician Conventional Plays. *Reservoir* 9: 18-25. Published by the Canadian Society of Petroleum Geologists.
[262] https://crsreports.congress.gov/product/pdf/RL/RL34741 . U.S. Congressional Research Service.

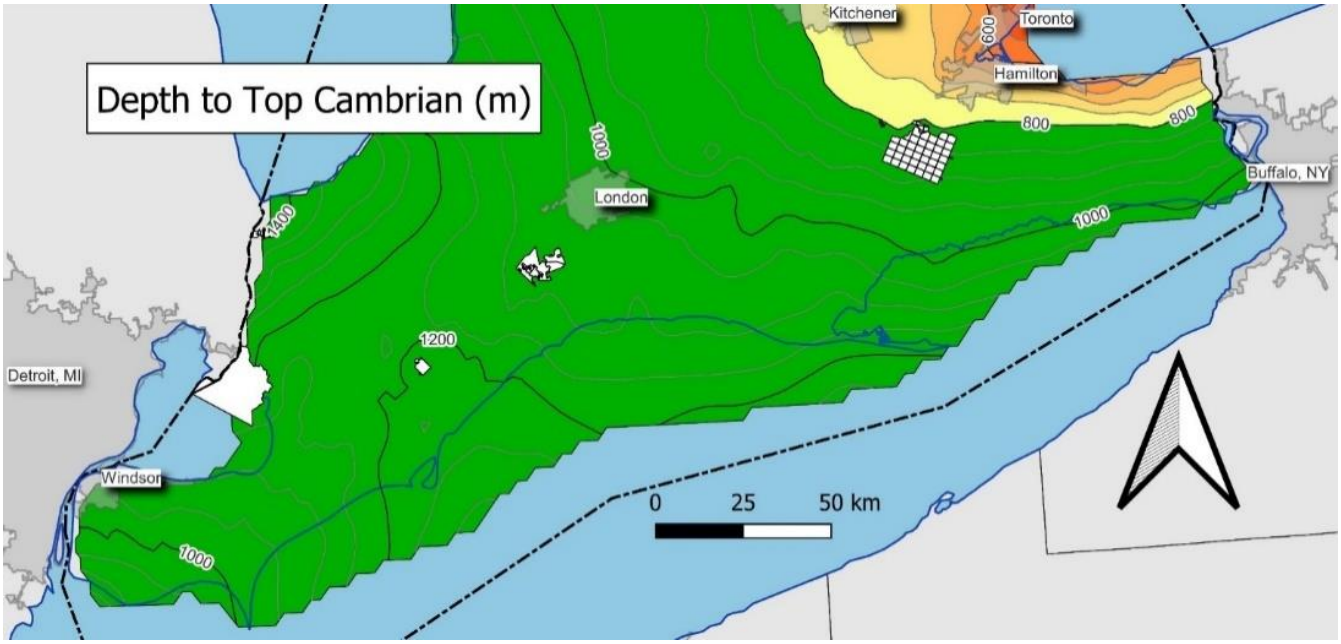

FIGURE 5-12 DEPTH TO THE TOP OF THE CAMBRIAN FM. IN METRES WHERE DEPTH IS GREATER THAN 800 M (*PREPARED BY BRUCE HART, WESTERN UNIVERSITY*)

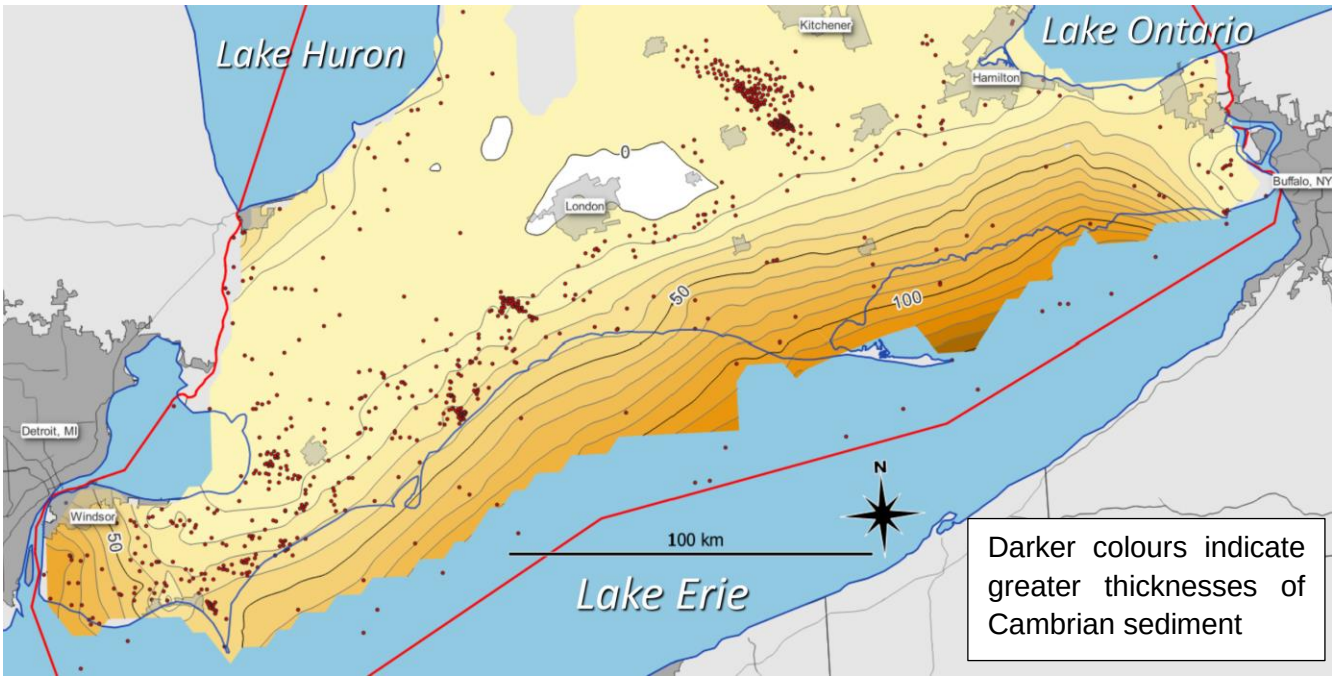

FIGURE 5-13 ISOPACH MAP OF CAMBRIAN FORMATION (CAMBRIAN FM. THICKNESS IN METRES, CONTROL WELLS USED TO DRAW FIGURE SHOWN; *PREPARED BY BRUCE HART, WESTERN UNIVERSITY*)

The Cambrian of SW Ontario overlies the Precambrian basement of granitic rocks. It contains two lithofacies: a low-permeability dolomite and inter-layered moderately permeable sandstone. Figure 5-14, which is based on borehole T012159 located in Lake Erie offshore from Nanticoke, shows these two

facies. The lower sandstone unit in Figure 5-14 is equivalent to the Mt. Simon of the US Midwest. The Cambrian generally becomes more dolomitic in the upper sections. The lowermost caprock for the Cambrian is the Gull River Limestone, which together comprise the geological CO_2 storage system, which ideally will also have an impermeable underlying basement seal.[263]

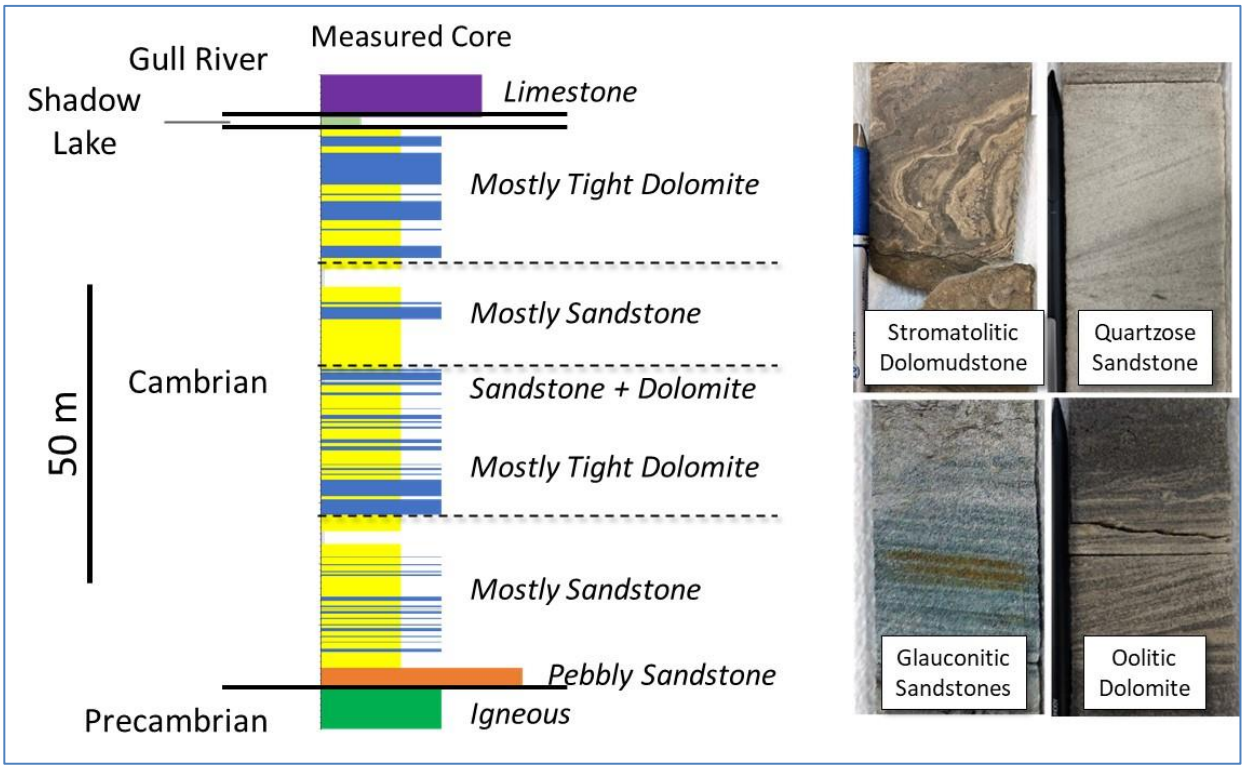

FIGURE 5-14 SCHEMATIC OF THE CAMBRIAN FORMATION BENEATH LAKE ERIE IN WELL T012159 (*PREPARED BY BRUCE HART, WESTERN UNIVERSITY*)

The permeability and porosity of the Cambrian is illustrated in Figure 5-15 that shows the measurements of permeability and porosity from core plugs extracted from T012159. The lowermost section, presumably equivalent to the Mt. Simon Fm., is the most permeable in this core with several core plugs exhibiting 100 millidarcy (mD) values, equivalent to a hydraulic conductivity of 10^{-6} m/s. Porosities in this section are between 10% and 20%. Higher in the Cambrian, the permeability and porosity are clearly lower presumably due to textural fining.

The caprock for the Cambrian is not the Shadow Lake Fm., which is often a sandy dolomite, but rather the Gull River Fm. and higher tight limestone units that were measured in-situ at the Bruce Nuclear site

[263] The Royal Society (UK), 2022. *Locked Away – Geological Carbon Storage.* London, UK. https://royalsociety.org/-/media/policy/projects/geological-carbon-storage/Geological-Carbon-Storage_briefing.pdf

as having only ~2% porosity and a horizontal permeability of $2x10^{-12}$ m/s[264], which suggests a vertical permeability of 10^{-13} to 10^{-15} m/s. The properties of the Precambrian basement are poorly known.

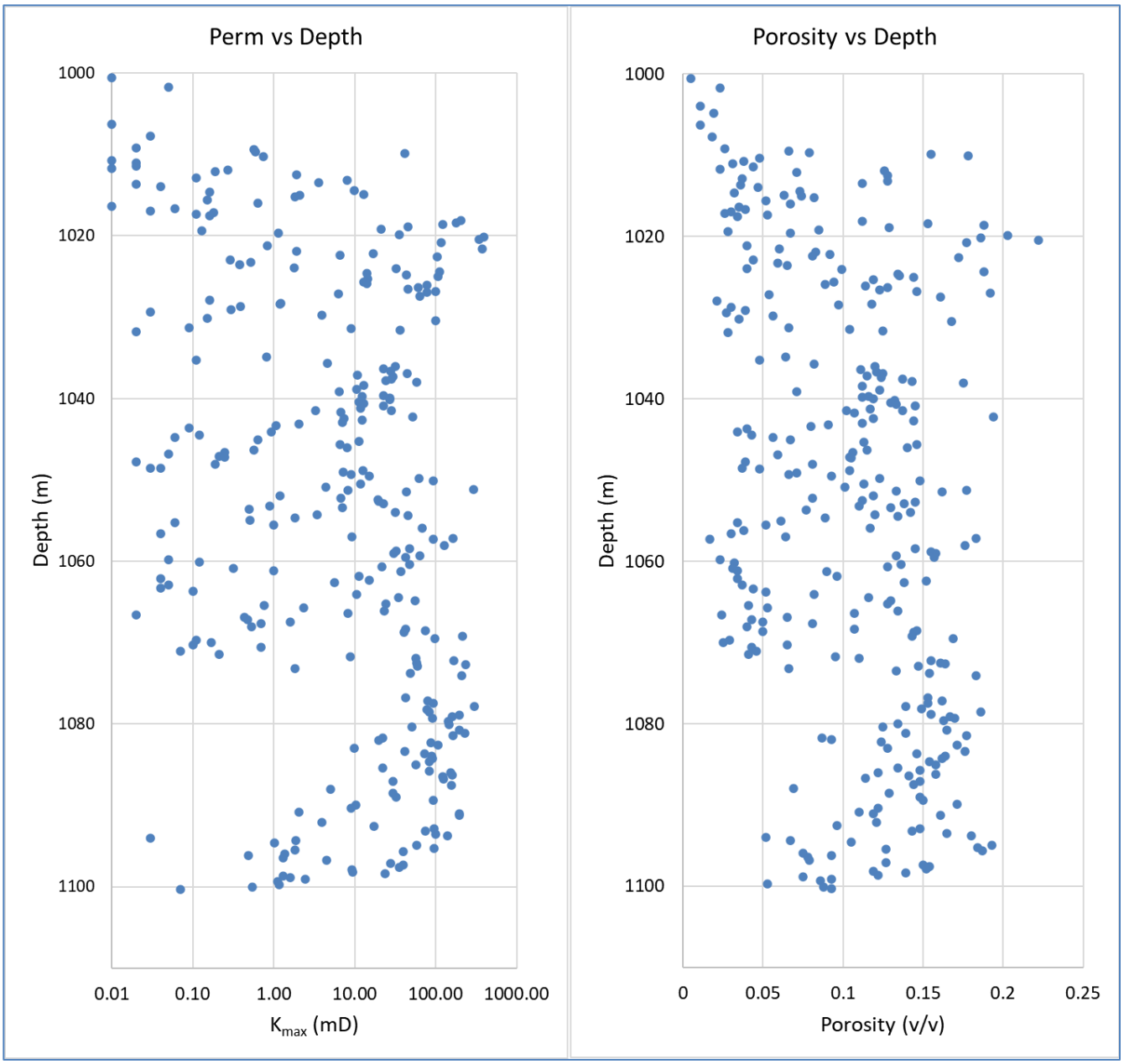

FIGURE 5-15 PERMEABILITY AND POROSITY OF THE CAMBRIAN FORMATION, LAKE ERIE IN WELL T012159 (PREPARED FROM OGSRL DATA)

[264] INTERA Engineering (now Geofirma Engineering), 2011. *Descriptive Geosphere Site Model.* NWMO DGR-TR-2011-24. NWMO Toronto, Ontario.

5.4 Depleted Oil and Gas Fields as Storage Reservoirs

While the Federal Government is not encouraging the use of depleted oil and gas fields as storage reservoirs for CO_2, the Government of Ontario has permitted enhanced oil recovery (EOR) or enhanced gas recovery within these reservoirs. Numerous, small, depleted Cambrian and Ordovician reservoirs have sufficient depth for geological CO_2 storage[265]. Alberta Innovates[266] has published characteristics of oil reservoirs suitable for miscible CO_2-EOR.

Within the Cambrian Fm. are several small producing oil fields along the north shore of Lake Erie, such as the Willey and Clearville fields, as described by Dorland and colleagues. Two fields situated to the southwest of Kitchener, the Innerkip gas field and the Gobles oil field, are now believed to be part of the Ordovician Shadow Lake Fm. The total oil production from the Gobles, Willey and Clearville pools had reached over 5 million barrels (>0.8 x 10^6 m^3) by the end of 2015. These fields are believed to be structural traps, either associated with faulting or with the pinching out of the reservoir.

The other depleted oil fields that may considered for geological CO_2 storage are the hydrothermal dolomite reservoirs of the Ordovician Trenton-Black River group in Kent and Essex counties (see Dorland et al.). These reservoirs are typically 300 m to 1 km wide and up to 15 km long with individual oil production volumes of 100,000 to 1,000,000 m^3. Figure 5-16 illustrates how these are fault-related fields in which the limestone has become dolomitized and made permeable and then invaded by oil from adjacent rocks. While confined by the overlying Ordovician shales, the through-going faults suggest that high injection pressures during CO_2 injection could cause slippage in the basement rocks.

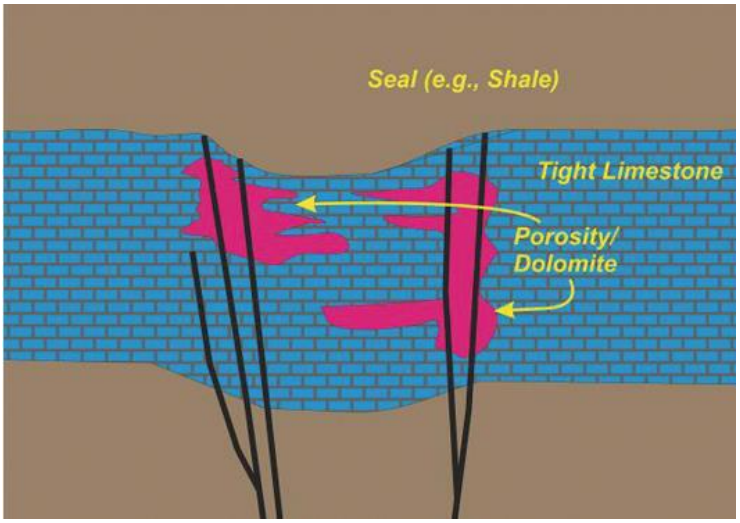

FIGURE 5-16 SCHEMATIC CROSS SECTION OF A HYDROTHERMAL DOLOMITE RESERVOIR[267]

[265] Dorland et al., 2016, ibid.

[266] Zhou, J., et al., 2022. *Carbon Capture, Utilization, and Storage (CCUS): Technology Innovation to Accelerate Broad Deployment in Alberta.* Alberta Innovates, Edmonton, Alberta. See Figure 4.

[267] Figure from Hart, B.S., Sagan, J.A. and Ogiesoba, O.C., 2009. Lessons learned from 3-D seismic attribute studies of hydrothermal dolomite reservoirs. *CSEG Recorder*, *34*(5), pp.18-24.

The Innerkip gas field is a thin sandstone field that appears to be quite compartmentalized by faulting[268]. By the end of 2015, it had produced nearly 800 million m^3 of natural gas. Were this natural gas replaced with CO_2 at a non-supercritical density of only 100 kg/m^3 and at the initial discovery pressure of only 3.8 MPa, it could store about 2 MT CO_2 without considering temperature effects. However, the field contains about 200 gas wells, most of which would have to be plugged and abandoned at a unit cost of perhaps $100,000 per well. Reservoir compartmentalization might also require numerous injection wells.

5.5 Evaluating the Storage Capacity of the Cambrian Saline Aquifer

The 2004 study by Shafeen and colleagues (hereafter referred to as "Shafeen") is illustrated by Figure 5-17, which shows the areas of SW Ontario that they considered suitable for geological CO_2 storage[269]. The northern zone (NZ) of this figure is centered on Lake Huron, while the southern zone (SZ) is centered on Lake Erie. The NZ is undrilled except at the Bruce Nuclear site[270] where the Cambrian was artesian; this suggests that the Cambrian may be unsuitable beneath near-shore Lake Huron (see section 5.2.4).

An inspection of Figure 5-17 indicates that a large fraction of this total storage capacity of 442 MT is off-shore beneath Lake Erie and relatively close to US territory, therefore the on-shore storage capacity will be reduced by that amount off-shore. Pressurization of the US Cambrian caused by injection operations beneath the Canadian lakebed would have to be secured by treaty and by provision of liability coverage should any of the numerous active and abandoned, oil and gas wells on the US shore be affected by pressurization caused by Canadian injection operations. Furthermore, Figure 5-13, based on revised geological interpretations since 2004, indicates that Shafeen's estimate may have somewhat underestimated the onshore storage volume of the Cambrian in the SZ area.

The values of storage capacity shown are given by the material balance: *storage capacity = (displaceable volume + dissolved volume of CO_2 in pore water)*. The '*displaceable volume'* refers to the volume of brine displaced by the injection of CO_2; the '*dissolved volume of CO_2 in pore water*' is a function of the solubility of CO_2 in brine. The expression employed by Shafeen to obtain the storage capacity or storage resource estimate of the southern zone (SRE_{SZ}) of the Cambrian Fm. shown in Figure 5-17 is:

$$SRE_{SZ} = E_f\ A\ h\ \phi\ [S_g/B_{g,(CO2)} + (1-S_g)R_{s,(CO2)}] \ldots. (1)$$

Where E_f: the sweep efficiency of the CO_2 injection, (fraction of aquifer contacted by CO_2);
A: the area of the saline aquifer, (m^2);
h: the thickness of the saline aquifer, (m);
ϕ: the average effective porosity of the saline aquifer, (fraction of aquifer volume);
S_g: saturation of CO_2 retained as gas within the aquifer, (fraction of pore volume);
$R_{s,(CO2)}$: CO_2 solubility in brine (m^3/m^3);

[268] McIntosh, J., *Innerkip Cambrian Gas Pool: Pressure and Production History.* Acquired from the OGSRL, London.
[269] Shafeen et al., 2004, op. cit.
[270] INTERA Engineering (now Geofirma Engineering), 2011. *Descriptive Geosphere Site Model.* NWMO DGR-TR-2011-24. NWMO Toronto, Ontario.

$B_{g(CO2)}$: gas formation volume factor for CO_2 expressing the in-situ volume of CO_2 to volume at at standard temperature and pressure, (m^3/m^3).

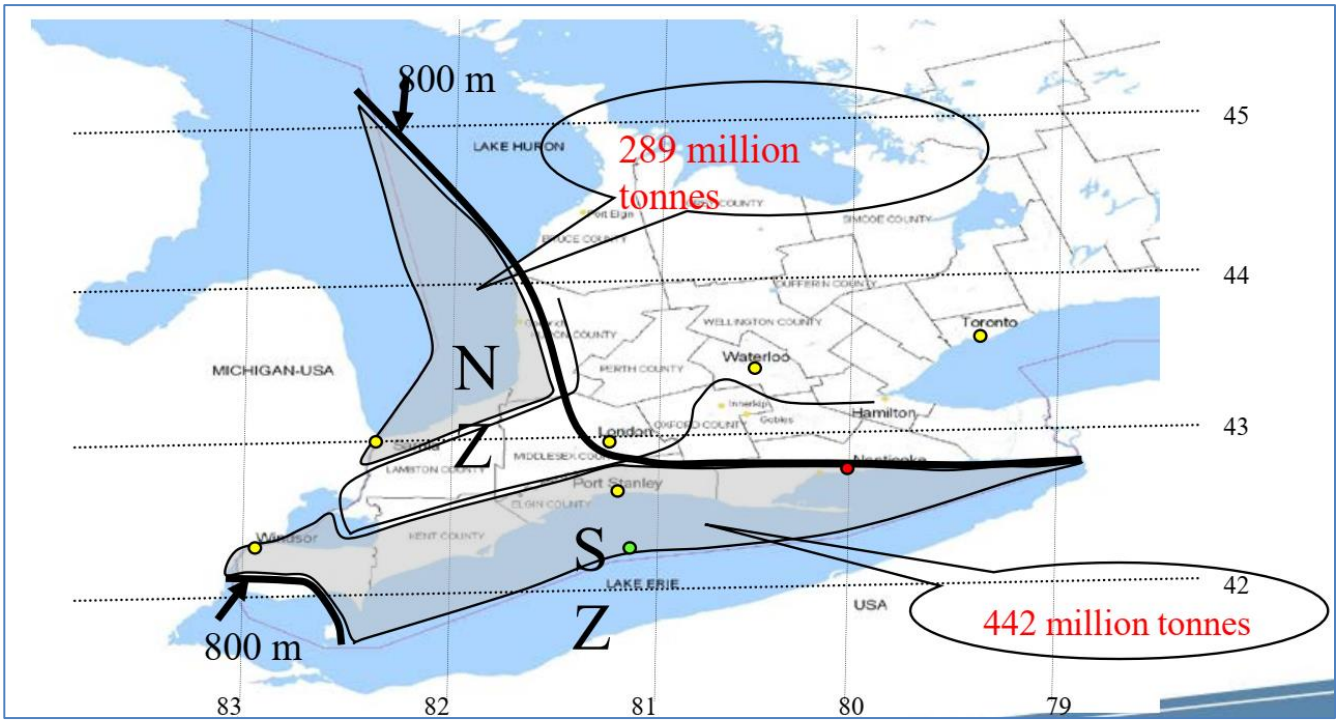

FIGURE 5-17 SHAFEEN ET AL.'S ESTIMATION OF GEOLOGICAL CO2 STORAGE IN SW ONTARIO

Experience since Shafeen's pioneering work has quantified this inefficiency of storage during CO_2 injection operations. In his work, Shafeen used a sweep efficiency of 10%, which is now considered high when only injection of CO_2 is employed, and no reservoir management techniques are employed to maximize the more widespread migration of the CO_2 within the saline aquifer. For example, Table 5-1 lists the estimates compiled by US DOE, indicating that the most probable SRE for the Ontario Cambrian sandstone is 2% not 10%, and the range of most probable values is from 5.4% to 0.5%. P_{90} indicates that 90% of estimates obtained, based on documented ranges derived from oil and gas reservoirs and by 5,000 Monte Carlo simulations thereof, were less than this value.

TABLE 5-1 STORAGE EFFICIENCIES FOR CLASTIC AND CARBONATE SALINE AQUIFERS[271]

Lithology	P_{10}	P_{50}	P_{90}
Clastic (sandstones, etc.)	0.51%	2.00%	5.40%
Dolomite	0.64%	2.20%	5.50%
Limestone	0.40%	1.50%	4.10%

[271] NETL/US DOE, *2010 Carbon Sequestration Atlas of the United States and Canada*. Prepared by Southern States Energy Board, Peachtree Corners, Georgia, for US DOE/NETL. https://www.osti.gov/biblio/1814019

Equation 1 differs from other expressions employed to estimate the storage capacity of saline aquifers in that it incorporates terms associated with reservoir engineering. Most storage resource evaluations in the US use the US Department of Energy's prospective volumetric estimation method that Battelle[272] has written as:

$$SRE = E_S \rho_{CO2} h_n \phi_{ave} (0.3048 \cdot 10^6 \cdot 10^{-9}) \ldots. (2)$$

Where E_s: the storage efficiency of the CO_2 injection, (fraction of aquifer contacted by CO_2);
ρ_{CO2}: the density of CO_2 (kg/m^3);
h_n: the thickness of the saline aquifer, (m);
ϕ_{ave}: the average effective porosity of the saline aquifer, (fraction of aquifer volume);
where SRE is in units of mass per unit area (MT/km^2), while the other units are conversion factors from US to metric units. Values based on these CO_2 storage resource estimates assume a physically-accessible CO_2 storage pore volume (i.e., an effective porosity) in a saline aquifer and that the storage reservoirs are open systems in which the brine will either be displaced from the injection zone or produced and the aquifer's pressure response to injection thus managed.

It should be appreciated that estimates from equations 1 and 2 are prospective volumetric estimates based on estimated parameters from databases compiled, usually, from oil and gas records. A comparison of these various methods indicates their similarity:

> *Assessments of CO_2 storage potential made at the prospective level can be treated as giving comparable results relative to our typical knowledge of the relevant geologic input values when assessing CO_2 storage potential. Because different methods yield similar storage estimates at the prospective level, CO_2 storage method choice is not critical. In general, the uncertainty in the underlying geologic parameters has a much greater impact on overall estimates of CO_2 storage resource than the choice of method does, especially within subsets of methods defined by their boundary assumptions*[273]*.*

This conclusion confirms the vital importance of site characterization to estimate the "*underlying geologic parameters*" referred to and, therefore, the critical need for exploratory boreholes to test the potential target saline aquifers.

Bachu[274] has provided an in-depth review of the concept of the storage efficiency of an aquifer, in which he identifies four general categories of influencing factors:

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[272] Gupta, Neeraj, Medina, Cristian R., Rupp, John A., and Ellett, Kevin M., 2020. *Ordovician-Cambrian Units: Hierarchical Evaluation of Geologic Carbon Storage Resource Estimates*. Prepared by Battelle Institute for US DOE/NETL. Web. doi:10.2172/1773053. https://www.osti.gov/biblio/1773053.

[273] Goodman, A., Bromhal, G., Strazisar, B., Rodosta, T., Guthrie, W.F., Allen, D. and Guthrie, G., 2013. Comparison of methods for geologic storage of carbon dioxide in saline formations. *International Journal of Greenhouse Gas Control*, *18*, pp.329-342.

[274] Bachu, S., 2015. Review of CO2 storage efficiency in deep saline aquifers. *International Journal of Greenhouse Gas Control*, *40*, pp.188-202.

1. The inherent properties of the aquifer itself, such as petrophysical and geochemical parameters, its pressure distribution and its lithology.
2. The characteristics of the confining layers above the aquifer as defined by their permeability and capillary entry pressure.
3. The nature of the CO_2 injection operations including injection rates, number of injection wells and the reservoir engineering involved in CO_2 injection and pressure management.
4. The constraints imposed by the regulatory authority that govern permissible bottom-hole pressures and those pressures that can be exerted on the caprock.

With field-derived values of the critical parameters, it is possible to compute dynamic storage estimates[275]. The simplest of these is the approach of Okwen et al.[276] that is based on the analytical models developed by Nordbotten et al. (2005)[277] and Nordbotten and Celia (2006)[278]. This algorithm yielded a storage efficiency of 5% for the Sleipner North Sea field CCS project that matched the value estimated by time-lapse seismic data after 20 years.[279]

The best estimates will be developed using compositional numerical simulators that incorporate the physics and physical chemistry of CO_2 migration behaviour following injection, as shown in Figure 5-2. These include GEM, ECLIPSE or TOUGH3/ECO2M, which was used to develop Figure 5-9. However, the use of such simulators is predicated on the acquisition of high quality in-situ data, without which the simpler analytical approach of Okwen et al.[280] must suffice until this data is acquired.

Therefore, the Shafeen estimate of 2004 should be appreciated as an early attempt with inadequate field data to obtain a prospective storage volume. Table 5-1 indicates that a storage efficiency of 2% rather than 10% would be appropriate. Adjusting the area of the Cambrian sandstone beneath SW Ontario to our current understanding would also reduce the available pore volume for CO_2 storage. Were this estimation done with today's knowledge, a total pore volume of ~100 MT_{CO2} storage would probably be the maximum Shafeen's approach would produce, although this estimate is very weak.

Meaningful quantitative estimates, on which final investment decisions can be based, must come from field testing of injection and observation wells that are drilled to measure injectivity and compressibility so that both CO_2 injection volumes and the subsequent pressure-dome response can be simulated with a much higher degree of reliability than can be obtained from prospective volumetric estimation methods. These simulations should be conducted using compositional simulators such as those mentioned above.

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[275] IEAGHG, 2018. *CO_2 Storage Efficiency in Deep Saline Formations – Stage 2.* IEAGHG 2018-02, Cheltenham UK.
[276] Okwen, R.T., Stewart, M.T. and Cunningham, J.A., 2010. Analytical solution for estimating storage efficiency of geologic sequestration of CO2. *International Journal of Greenhouse Gas Control*, 4(1), pp.102-107.
[277] Nordbotten, J.M., Celia, M.A. and Bachu, S., 2005. Injection and storage of CO 2 in deep saline aquifers: analytical solution for CO_2 plume evolution during injection. *Transport in Porous Media*, 58:339-360.
[278] Nordbotten, J.M. and Celia, M.A., 2006. Similarity solutions for fluid injection into confined aquifers. *Journal of Fluid Mechanics*, *561*, pp.307-327.
[279] Ringrose, P., 2020. *How to store CO_2 underground: Insights from early-mover CCS projects* Berlin/Heidelberg, Germany: Springer International Publishing.
[280] Okwan et al., 2010, ibid.

The most promising areas for exploration are along the north shore of Lake Erie where the Cambrian is over 800 m deep and has thicknesses of 60 m or more. All of these sites are ~20 km or more from the US border (See Figure 5-18). The direction of buoyant CO_2 migration will likely be to the north in the Cambrian at Long Point and Port Maitland but may be southwestwards beneath Essex County.

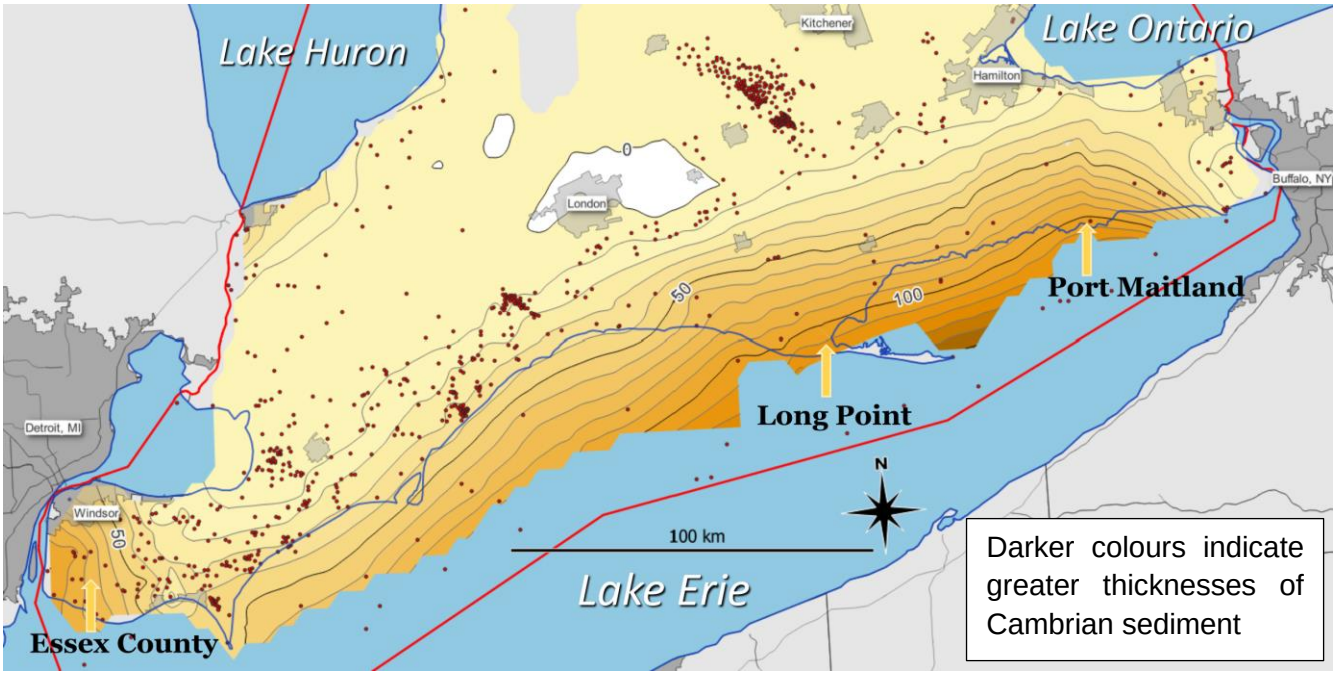

FIGURE 5-18 FAVORABLE SITES FOR EXPLORATORY DRILLING[281]

Because the available storage will be constrained by the pressure response within the Cambrian Fm. as the brine is compressed due to CO_2 injection, it will be important to examine reservoir engineering strategies to enhance injectivity. These include brine extraction and reinjection elsewhere in the subsurface. These have already been considered in Alberta[282] and the Illinois Basin[283] and are especially important in SW Ontario where the limits to storage are clear.

5.6 Pilot Injection Testing of Storage Reservoirs to Prove Suitability

A critical step in implementing a geological CO_2 storage hub is the completion of site characterization involving drilled, cored and tested boreholes that provide "*high certainty prior to physically locating any*

[281] Figure prepared by Bruce Hart, Western University.
[282] Leonenko, Y. and Keith, D.W., 2008. Reservoir engineering to accelerate the dissolution of CO_2 stored in aquifers. *Environmental Science & Technology*, *42*(8), pp.2742-2747.
[283] Plampin, M.R., Anderson, S.T., Finsterle, S. and Cahan, S.M., 2023. Dynamic estimates of geologic CO_2 storage resources in the Illinois Basin constrained by reinjectivity of brine extracted for pressure management. *Greenhouse Gases: Science and Technology*, *13*(1), pp.31-4

capture plant or pipeline system" (Senior et al., 2011)[284]. To achieve this status and thus demonstrate proven storage, the following tasks should be undertaken:

1. The drilling, coring and completion of an injection well – observation well pair in the saline aquifer. The wells might be 50-100 meters apart depending on formation permeability.

2. The hydraulic testing of this well pair to obtain a reliable estimate of the transmissivity and storativity of saline aquifer from which the formation's bulk compressibility can be derived. [N.B. while transmissivity can be approximated with a single well test, compressibility requires a two well test and is essential in steps 3 and 4 below.]

3. Numerical simulation of the hydraulic test to design a CO_2 injection test in this test-well site so that the migration of the CO_2 may be estimated, and the far-field pressure response of the saline aquifer predicted.

4. A pilot test of CO_2 injection over a period of several weeks to observe pressure response and CO_2 migration in the saline aquifer. [N.B. It may be decided that, for safety's sake, the closely spaced observation well in step 1 should be plugged and abandoned before this step and another drilled more distant from the injection well.] An example of such a test was conducted by Battelle in northern Michigan[285].

Such tasks require a minimum of three years and as long as eight years to complete. Therefore, site characterization starting in 2023 might be completed some time between late 2025 and 2030, after which time final investment decisions may be made regarding carbon capture at emitting plants and pipeline construction. Industry workshops held at the University of Waterloo in late 2022 indicate that proven geological storage will be required prior to any final investment decisions being made.

With the satisfactory completion of these characterization tasks, sites may be considered 'storage ready'. Proving a site 'storage ready' requires pilot injection testing that will allow the development team sufficient geological, physical and chemical information about the saline aquifer that it might simulate the migration and fate of CO_2 for at least 20 years thereafter. This would allow the storage to be considered proven for whatever tonnage might be injected.

While it is the case that 2 or 3 injection wells at the Quest site in Alberta can inject a total of 1 MT/yr, this will not be the case in the Cambrian of SW Ontario. Without evidence of higher injection rates, it should be assumed that a typical injection well drilled into the Cambrian sandstone of SW Ontario will be capable of injecting ~200 ± 100 kT/yr. Therefore, assuming an average injection rate of 200 kT/yr, some 50 injection wells would be needed along the north shore of Lake Erie to achieve the 10 MT/yr rate of total CO_2 injection. By the end of 2022, only one such well had been completed.

[284] Senior, B., Bradshaw, J., Chikkatur, A. and Wright, M., 2011. Planning saline reservoir storage developments—the importance of getting started early. *Energy Procedia*, 4, pp.4575-4582.
[285] Sminchak, J., Gupta, N. and Gerst, J., 2009. Well test results and reservoir performance for a carbon dioxide injection test in the Bass Islands Dolomite in the Michigan Basin. *Environmental Geosciences*, *16*(3), pp.153-162.

5.7 The Injectivity Index

The injectivity of the Cambrian sandstone has been explored across North America. Researchers at Battelle[286] use a measure known as the injectivity index (J) to compare injection rates:

$$J = \left|\frac{q}{\Delta p}\right| \ldots. \quad (3)$$

where q is the injection rate (T/yr) and Δp is the pressure difference between the formation (p_F) itself and the bottom-hole injection pressure (p_{BH}). Therefore, J is measured in units of tonnes per year per kPa pressure difference rather than per psi (1 kPa = 0.145 psi) as in the Battelle article. In Figure 5-19, the transmissivity is plotted in SI units as the product of permeability (m^2) *x* thickness (m) of the permeably layers, in which a permeability of 1 millidarcy = 10^{-15} m^2.

Battelle express the product of permeability and thickness in US petroleum units of millidarcy-feet. This is similar to the hydrogeological term 'transmissivity' and is shown in Figure 5-19 for some representative values from the North American Cambrian sandstones. Battelle show that plotting ten international CCS projects yields a median value of J = 0.08 kh, where J is in tonnes/year-psi and kh is in millidarcies-feet. In SI units, the trendline has the formula: J ~ 3.8 x 10^{13} kh.

The injectivities of potential geological storage hubs in SW Ontario are yet to be determined but are estimated in Figure 5-19 and plotted along the Battelle trend line for four Ontario counties. Based on this relationship, it might be expected that a Cambrian sandstone layer of 40 m thickness with a 10 millidarcy permeability might plot on Figure 5-19 downslope of the Aquistore symbol. This explains why thicker units of more permeable rock, continuous over large distances, are desirable for geological CO_2 storage. The units of the injectivity index indicate that CO_2 injection will be limited by a large Δp caused by the compression of brine and other fluids such as natural gas contained within the storage reservoir.

The Battelle research group, which has been responsible for the operations and management of the Midwest Regional Carbon Sequestration Partnership from 2003 to 2020, point out that the injectivity index has two main benefits in that it allows estimation of:

1. The pressure buildup due to a particular target injection rate.

2. The 'transmissivity' without long-term hydraulic transient test analysis.

[286] Valluri, M., Mishra, S. and Ravi Ganesh, P., 2021. Injectivity index: a powerful tool for characterizing CO2 storage reservoirs—a technical note. *Greenhouse Gases: Science and Technology*, *11*(2), pp.251-265.

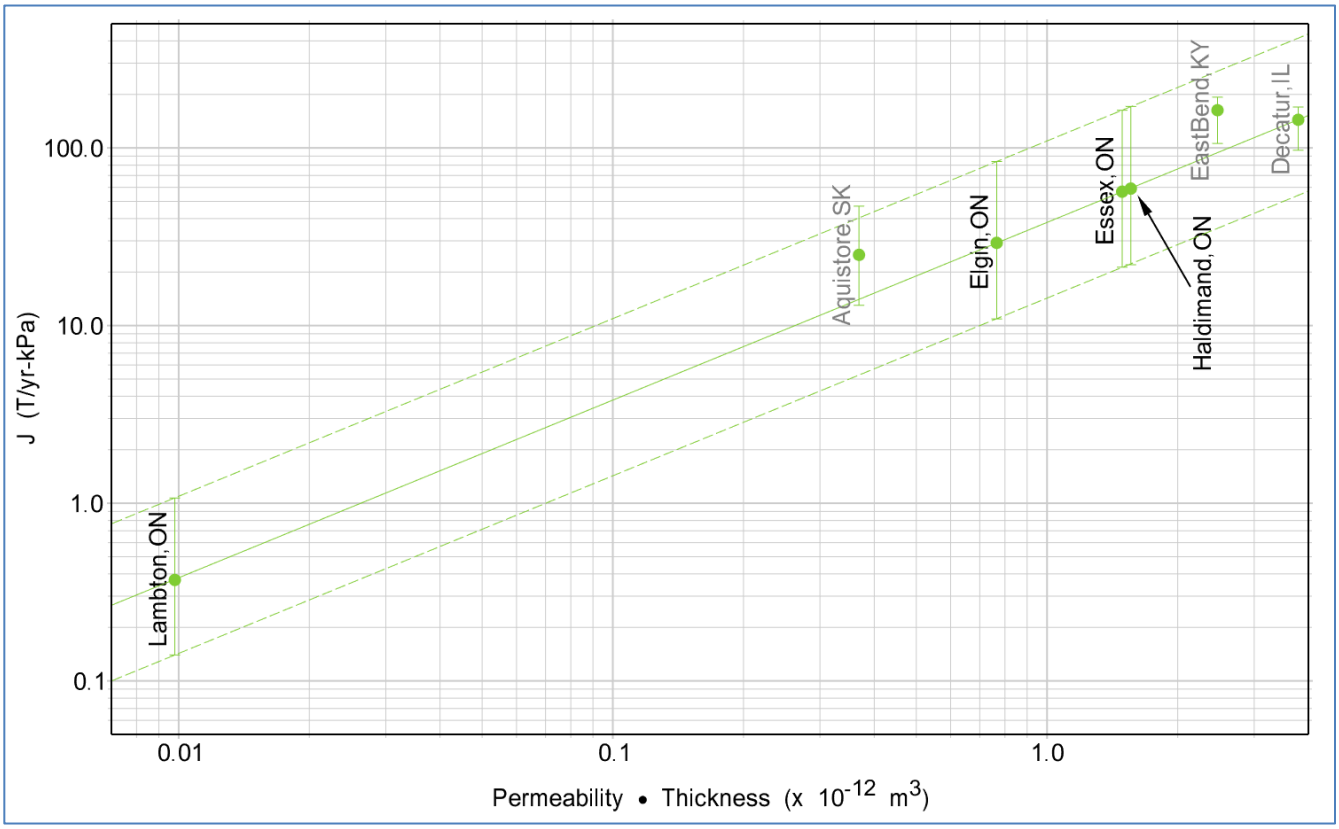

FIGURE 5-19 THE INJECTIVITY INDEX OF THE CAMBRIAN SANDSTONE

5.8 Seismic Stability during CO_2 Injection

The potential for earthquake triggering from CO_2 injection was raised in 2012 by two eminent Stanford University professors[287]. They argued that (i) the relatively low permeability of storage reservoirs and (ii) the potential for critically stressed faults to exist beneath these reservoirs made CO_2 injection liable to cause felt earthquakes. They identified the potential for both induced seismicity in the crystalline basement rock and a threat to caprock integrity. They concluded that geological CO_2 storage was "*a risky, likely unsuccessful strategy for reducing greenhouse gas emissions.*" This conclusion has been challenged in the literature[288] and appears overly pessimistic based on available field evidence[289,290].

[287] Zoback, M.D. and Gorelick, S.M., 2012. Earthquake triggering and large-scale geologic storage of carbon dioxide. *Proceedings of the National Academy of Sciences*, *109*(26), pp.10164-10168.
[288] Juanes, R., Hager, B.H. and Herzog, H.J., 2012. No geologic evidence that seismicity causes fault leakage that would render large-scale carbon capture and storage unsuccessful. *Proceedings of the National Academy of Sciences*, *109*(52), pp. E3623-E3623.
[289] Bauer, R.A., Will, R., Greenberg, S.E. and Whittaker, S.G., 2019. Illinois basin–Decatur Project. In *Geophysics and Geosequestration*. Cambridge University Press, pp. 339-369.
[290] Maxwell, S., 2019. Microseismic Imaging of CO_2 Injection. In *Geophysics and Geosequestration*, Cambridge University Press, pp. 174-178.

Nevertheless, there is ample evidence of induced seismicity from the injection of wastewaters into the subsurface[291,292] causing slippage along fault zones. Of concern to CCS operations along the north shore of Lake Erie was the occurrence of minor earthquakes, including one of M3.6, associated with a 1.8 km deep industrial disposal well across Lake Erie near Ashtabula, Ohio in 1987[293].

At least, the geomechanical integrity of the caprock seals to Cambrian reservoirs can be readily tested. The testing of caprock sealing gas storage reservoirs in SW Ontario has demonstrably ensured their safe use. It is the brittle Precambrian basement rock, however, that is of greater concern here. The depth to this rock surface is shown below in Figure 5-20 in metres above sea level (masl) where -800 indicates the basement surface is at a depth of 800 m below sea level and thus ~1000 m below ground surface.

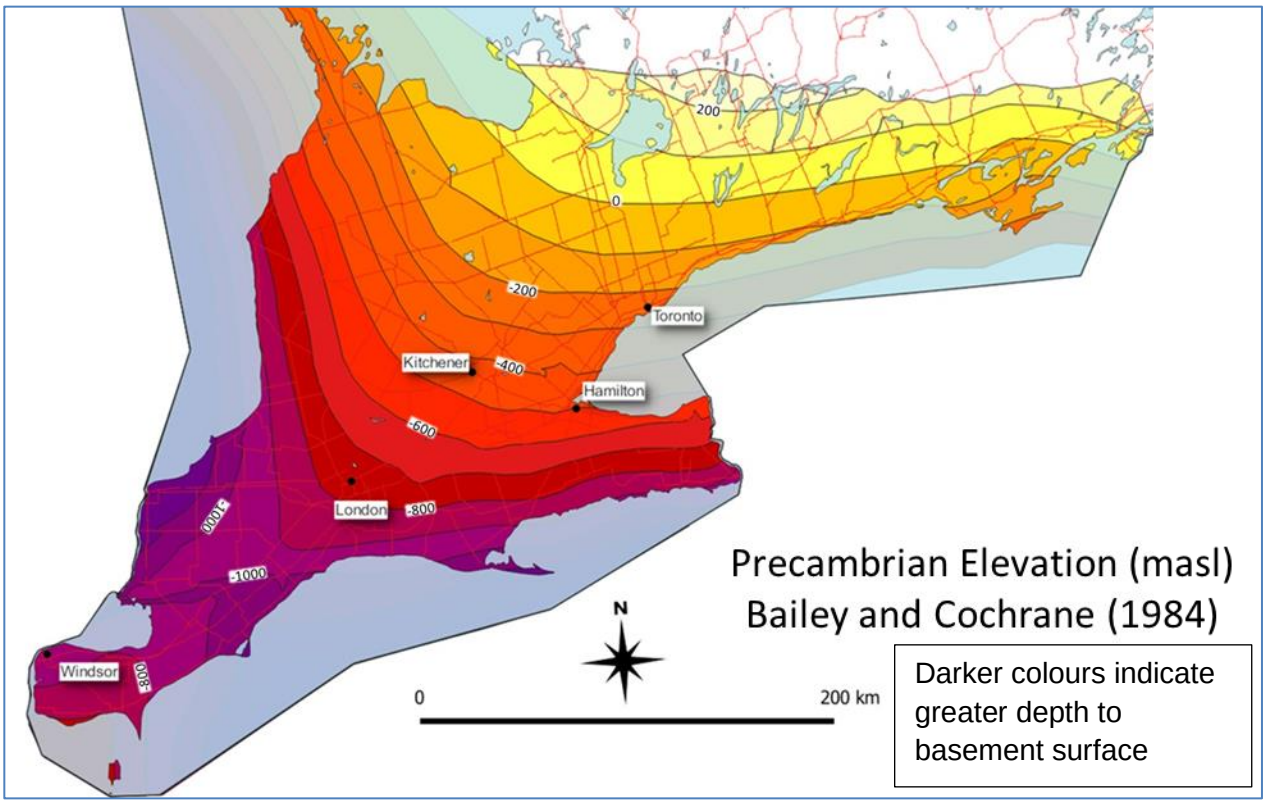

FIGURE 5-20 ELEVATION OF THE TOP OF THE PRECAMBRIAN BASEMENT[294]

[291] Ellsworth, W.L., 2013. Injection-induced earthquakes. *Science*, *341*, DOI:10:1126/Science. 1225942.

[292] Grigoli, F., Cesca, S., Priolo, E., Rinaldi, A.P., Clinton, J.F., Stabile, T.A., Dost, B., Fernandez, M.G., Wiemer, S. and Dahm, T., 2017. Current challenges in monitoring, discrimination, and management of induced seismicity related to underground industrial activities: A European perspective. *Reviews of Geophysics*, *55*(2), pp.310-340.

[293] Nicholson, C., and Wesson, R.L., 1990. *Earthquake Hazard Associated With Deep Well Injection*. A Report to the U.S. Environmental Protection Agency. U.S. Geological Survey Bulletin 1951.

[294] Figure prepared by Bruce Hart, Western University.

The detection of Precambrian basement faults is hindered by their vertical or sub-vertical geometry and the lack of marker beds in sedimentary rocks that allow slippage to be calculated. Reanalysis of existing data and acquisition of new data optimized for basement fault detection is needed.[295] Figure 5-21 shows the suspected located of basement faults in the Lake Erie region. The cluster of earthquakes around Ashtabula, Ohio and the Niagara peninsula emphasizes the need to further investigate the characteristics of basement faulting in SW Ontario.

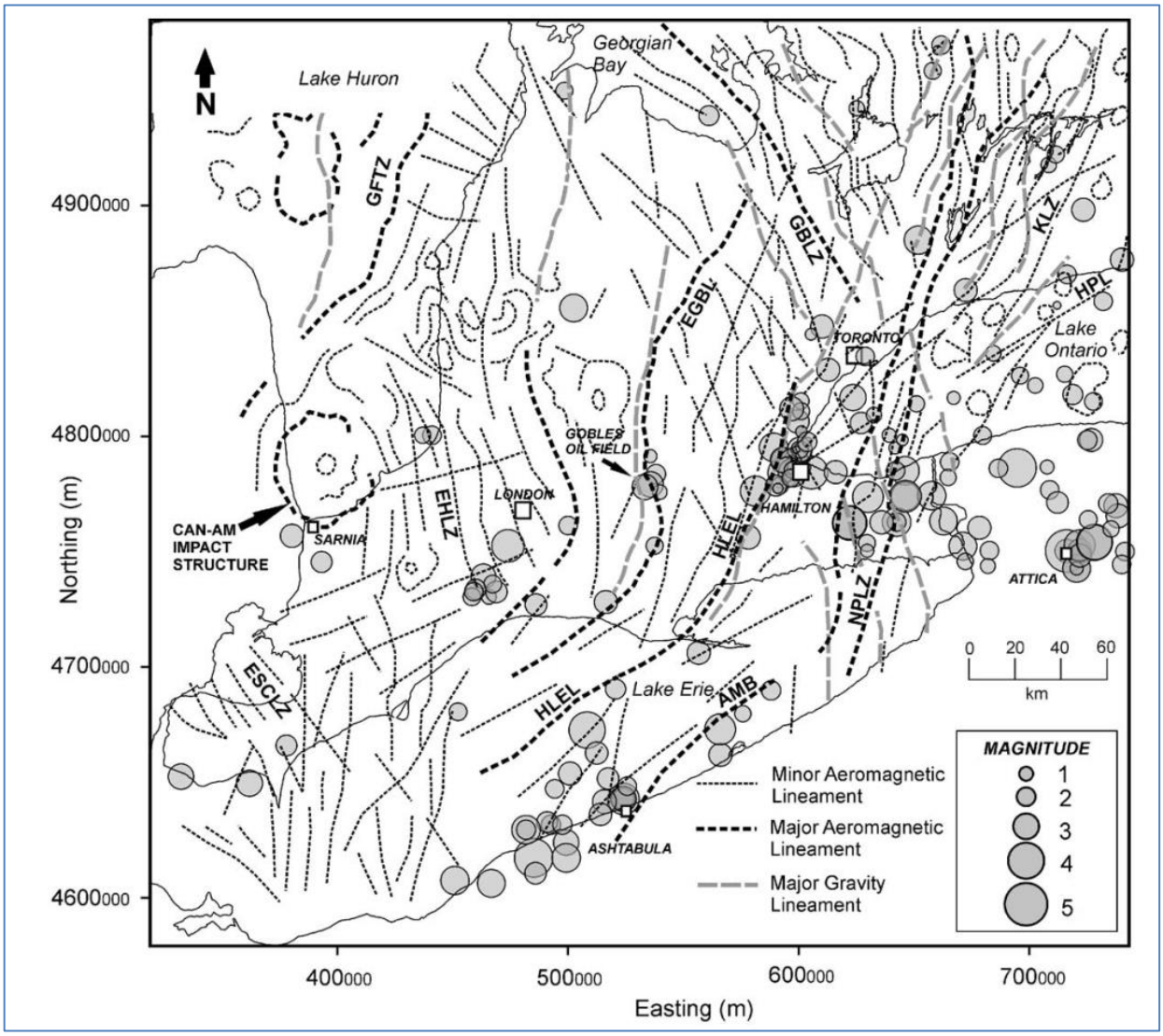

FIGURE 5-21 DISTRIBUTION OF EARTHQUAKE EPICENTRES (PERIOD 1840– 2000) IN SOUTHERN ONTARIO OVERLAID ON BASEMENT GEOPHYSICAL LINEAMENTS[296],.

[295] National Academies of Sciences, Engineering, and Medicine 2019. Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. https://doi.org/10.17226/25259.
[296] Boyce, J. and Morris, W., 2002. Basement-controlled faulting of Paleozoic strata in southern Ontario. Canada: new evidence from geophysical lineament zapping: *Tectonophysics*, *353*, pp.151-171.

5.9 Recommendations

It is recommended that:

3: Exploratory drilling and formation testing of the Cambrian sandstone be undertaken in at least three areas along the north shore of Lake Erie during 2023-2025 to establish proven geological storage for storage hubs and measure in-situ stresses.

4: An RD&D test site in SW Ontario be developed by governments, industry and academia to demonstrate the steps required for proven storage including the pilot testing of CO_2 injection.

5: Reservoir engineering research, development, and demonstration be undertaken by governments, industry, and academia to determine how to best manage the pressurization of the Cambrian sandstone during CO_2 injection throughout Canada.

6: A geophysical exploration of existing faults along the north shore of Lake Erie should be undertaken by the federal and provincial geological surveys, especially to detect and characterize basement faults.

6 IMPLICATIONS FOR R&D THROUGH 2030

6.1 The 2006 CCS Technology Road Map

In 2006, NRCan released a road map on CCS Technology[297] -- hereafter referred to as CCSTRM -- that identified general areas in which Canada needed to invest resources to accomplish '*transformative change*' given the challenges of climate change. These areas were:

i. CCS policy and regulatory frameworks
ii. Public outreach and education
iii. Technology watch and international collaboration
iv. Science and technology R&D
v. Demonstrations
vi. National coordination

It is regrettable that only in Alberta and Saskatchewan are there commissioned facilities that are reducing emissions by a million tonnes per year with geological storage. . Ontario initially responded by calling a workshop in February 2006 that brought together Ontario's petroleum geologists with experts on geological CO_2 storage from Alberta to prepare a technology review and analysis of CCS opportunities in Ontario[298]. Ontario Power Generation proceeded to shut down its coal-powered generating stations and thus removed ~20 MT CO_2 from Canada's emissions by 2013. Only in 2022 has Ontario again shown an interest in CCS and has lifted its prohibition on the geological storage of CO_2. 17 years have therefore passed in Ontario without the '*transformative change*' that is required to implement CCS and the preservation of Ontario's industrial base.

The six areas of activity identified in the CCSTRM and listed above remain pertinent. Policy and a regulatory framework is only now under development in Ontario, but public outreach and education has been limited to three workshops organized by the Waterloo Institute for Sustainable Energy (WISE) at the University of Waterloo during 2021 and 2022 to address CCS regulations, opportunities, technologies, and industrial needs. Adoption of CCS in Ontario would be greatly facilitated by better informed elected officials and managers in the provincial and regional government, conservation authorities, and regulatory agencies. Therefore, it is recommended:

7: initiate a public outreach and education programme to inform Ontarians about CCS.

One private corporation has begun site investigations for geological storage and several others are exploring opportunities. Therefore, the geological storage R&D needs in Ontario are little changed from those identified in CCSTRM in 2006 (see Figure 5-2 of the CCSTRM, page 72). Fortunately, projects in Alberta, Saskatchewan, the North Sea and the USA have informed many of the issues identified.

[297] NRCan, 2006, *CCSTRM: Canada's CO_2 Capture & Storage Technology Roadmap.* NRCan, Ottawa.
[298] Carter, T. et al., 2007, op. cit.

Nevertheless, the 'short-term' issues that were to be resolved by 2010, now need to be addressed by 2025 as well as several of the issues belonging to the medium term, e.g., evaluating legacy oil and gas wells and critically stressed faults. These are considered in section 6.3 below.

6.2 Selecting CCS Hubs for Industrial Sectors

Three promising areas for the investigation of industrial CCS hubs are identified in Figure 5-18, all of which are situated along the north shore of Lake Erie where the Cambrian sandstone is the thickest.

a) Essex County, east of the city of Windsor, provides the closest potential Canadian storage hub for the oil refining and chemical industries in Sarnia-Lambton, approximately 140 km to the north, as well as the various manufacturing and food industries in Essex County itself.

b) The area of Norfolk County near Long Point also offers a thick section of Cambrian sediments. This area is also home to gas wells, both active and abandoned, although most of these gas wells did not penetrate beyond the uppermost Ordovician shale.

c) Haldimand County around Port Maitland appears to be an attractive site for geological storage for industry in Hamilton and surrounding area. However, Paleozoic rocks in this part of Haldimand County appear to be faulted, although little is known of the faults.

6.3 RD&D Needs to Develop the Cambrian Sandstone for Geological CO_2 Storage

In addition to the six general recommendations summarized in section 7, the Research Development and Demonstration (RD&D) requirements that should be undertaken in-house or otherwise funded by government, industry and academia (via NSERC, CFI, etc.) by 2030 include the following:

6.3.1 Geomechanical Issues

- *Caprock Integrity:* the Ordovician carbonate caprock sealing the Cambrian Fm. should be tested to determine the fracture and re-opening pressures. These pressures should allow limits to be set on the pressure response within the storage reservoir.

- *In-situ stress*: There are very few (or no) measurements of in-situ stress in the Cambrian formation and caprock of SW Ontario. Measurement of in-situ stresses should be a component of borehole drilling and testing programs, as they will be critical to understanding maximum safe injection pressures.

- *Basement faults:* High-precision geophysical surveys are needed to update our knowledge of the location and extent of basement faults along the north shore of Lake Erie.

- *Thermal effects following injection*: There is evidence from Aquistore that the thermal shock of the injected CO_2 caused fracturing of the reservoir near the injection well. The conditions under which such fracturing occurs should be determined. In addition, the risk of wellbore shear through activation of bedding plane slip arising from cooling or pressurization around the wellbore should be investigated.

- *Compressibility of the storage reservoir*: The pressure response of the geological reservoir is a controlling factor of its injectivity as shown in Figure 5-9. It is essential that this parameter be measured by two-well tests at all injection sites to allow reliable simulation of the pressure response to CO_2 injection.

- *Induced Seismicity*: The US National Academy of Sciences has noted that "*information and knowledge are not sufficient to distinguish low-risk from high-risk sites, particularly for sequestration in saline aquifer directly over basement rock*"[299]. They further pointed to the need for (i) developing short-term tests to assess the risks of induced earthquakes before a project has started; (ii) developing mitigation approaches for minimizing risks, e.g., brine extraction; and (iii) understanding the potential for fault slip to increase leakage from the storage reservoir.

6.3.2 Geochemical Issues

- *Natural Gas composition and saturation*: Well records from Cambrian wells across southern Ontario have documented gas shows, suggesting that residual gas may be widely present in Cambrian Fm of southern Ontario, even in down-dip areas (e.g., beneath Lake Erie) that lack structural or stratigraphic trapping mechanisms. By increasing the average compressibility of pore filling fluids, small amounts of residual gas saturation (e.g., 1-5 %) can have a significant effect on the overall compressibility of the reservoir. In addition, residual gas will affect liquid phase relative permeability and has potential compositional effects on the density of the CO_2 plume. Dissolution of CO_2 may be associated with exsolution of CH_4. This gas should be characterized as to its composition, characteristics, and particularly to its fluid saturation.

- *Salt precipitation around injection wells*: Salt precipitation following CO_2 injection can reduce the porosity and permeability of the storage reservoir significantly[300]. This process should be investigated in a petrophysics laboratory with Cambrian core to determine its significance.

- *Noble gas as a measure of reservoir connectivity*: the use of noble gases to determine storage reservoir connectivity[301] is an important development that is well worth pursuing as well as other tracer techniques. Already, for example, CanmetENERGY Devon is using noble gas geochemistry in studies of legacy-well leakage[302]. The ability to estimate the connectivity of a storage reservoir would be of great significance to those simulating long-term CO_2 migration and to those responsible for ensuring and monitoring the integrity of the storage reservoir.

[299] National Academies of Sciences, Engineering, and Medicine and Board of Ocean Studies, 2019. *Negative emissions technologies and reliable sequestration: A research agenda*. NASEM, Washington, D.C.
[300] Falcon-Suarez, I.H., Livo, K., Callow, B., Marin-Moreno, H., Prasad, M. and Best, A.I., 2020. Geophysical early warning of salt precipitation during geological carbon sequestration. *Scientific Reports*, *10*(1), p.16472.
[301] Scott, J.A., Pujol, M., Györe, D., Stuart, F.M. and Gilfillan, S.M.V., 2021. Determining static reservoir connectivity using noble gases. *Chemical Geology*, *582*, p.120410.
[302] Utting, N., Osadetz, K., Darrah, T.H., Brennwald, M.S., Mayer, B. and Lawton, D., 2022. Methods and benefits of measuring non-hydrocarbon gases from surface casing vents. *International Journal of Environmental Science and Technology*, pp.1-18.

- *Develop a methodology for use of noble gases as tracers, and other tracer techniques:* Noble gases have also been co-injected with CO_2 to act as tracers of CO_2 migration.[303] It is recommended that techniques for interwell testing be developed that will be useful during pilot tests of CO_2 injection.

- *Measurement, Monitoring, and Verification***:** identify guidelines that provincial and regional agencies can expect to be followed at CO_2 injection sites. These guidelines should describe the surface and subsurface measurements to be collected, the monitoring intervals for their collection and how the acquired data is to be verified.

6.3.3 Petrophysical Issues

- *Effects of CO_2 on caprock integrity***:** It is recommended that caprock brine permeability and CO_2 entry pressure characteristics be measured at ambient and in-situ conditions for the Ordovician carbonate rocks comprising the caprock. Imaging of the penetration by CO_2 would be desirable.

- *Relative permeability curves for the Cambrian sandstone***:** Brine – CO_2 relative permeability curves should be measured in the Cambrian sandstone at in-situ stress and temperatures that vary from 20°C to 50°C. The effect of 10% residual saturation of methane should be examined. is encouraged to determine the residual saturation of liquid-phase CO_2 in the Cambrian sandstone in the presence of brine and of brine and natural gas.

6.3.4 Hydrogeological Issues

- *Injectivity:* An important task to be investigated at a test site is the determination of what injection rates maximize the sweep of CO_2 within the saline aquifer, minimize the effects of salt precipitation in plugging pore throats through evaporation of residual saline water and investigate the need for water slugs to dissolve the salt episodically.

- *Large-scale fluid flow model of CO_2 migration and pressure response*: Alberta Innovates recently identified that absence of a regional pressure model of proposed hub interactions as being a critical concern.[304] A similar such model should be prepared for the Cambrian along the north shore of Lake Erie once reliable transmissivity and compressibility measurements are available. This model should simulate reservoir engineering approaches to limit brine pressure buildup.

- *Carbon isotope geochemistry of shallow potable groundwater adjacent to injection wells*: To preclude questionable claims of fugitive CO_2 from injection operations, baseline measurements should be made in potable groundwaters and wetlands near each injection site.[305]

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[303] Györe, D., Stuart, F.M., Gilfillan, S.M. and Waldron, S., 2015. Tracing injected CO_2 in the Cranfield enhanced oil recovery field (MS, USA) using He, Ne and Ar isotopes. *International Journal of Greenhouse Gas Control*, *42*, pp.554-561**.**

[304] Zhou, J., et al., 2022. *Carbon Capture, Utilization, and Storage (CCUS): Technology Innovation to Accelerate Broad Deployment in Alberta.* Alberta Innovates, Edmonton, Alberta.

[305] Sandau, C.D., Prokipchuk, M., Dominato, K.R. and Mundle, S.O., 2019. Soil gas investigation of an alleged gas migration issue on a residential farm located above the Weyburn-Midale CO2 enhanced oil recovery project. *International Journal of Greenhouse Gas Control*, *81*, pp.11-20.

6.3.5 Legacy Oil & Gas Wells

- *Location, characterization, and preferred methods of sealing of legacy wells:* Legacy and active wells within 20 km of a potential injection well should be located and characterized as to their total depth, cement completion, gas composition, and fluid pressure and composition prior to plugging and abandonment.

7 SUMMARY OF RECOMMENDATIONS AND TIMELINES

This section summarizes the general recommendations made in this Road Map for adoption by industry, government, and academia. Furthermore, it identifies tasks that are required to meet a 2030 deadline by completion in 2025 and 2028.

It is recommended that:

1: The federal and provincial governments ensure the proven availability of 10 MT/yr of geological CO_2 storage capacity by late 2025 in SW Ontario to allow manufacturing industry to proceed with FIDs regarding carbon capture and commit to pipeline construction. To be achieved by late 2025.

2: The possibility of laker (i.e., specialized ships) transportation of CO_2 through the Great Lakes should be considered system as an insurance should geological CO_2 storage fail to meet current expectations and to provide a lifeline to industrial emitters distant from potential geological storage hubs. To be achieved by 2028**.**

3: Exploratory drilling and formation testing of the Cambrian sandstone be undertaken in at least three areas along the north shore of Lake Erie during 2023-2025 to establish proven geological storage for CCS hubs and measure in-situ stresses. These sites are in Essex, Norfolk and Haldimand Counties. They should be developed as test sites where 1 km deep boreholes would be drilled, cored and tested for their suitability to become CO_2 injection wells. To be achieved by late 2025.

4: An RD&D test site in SW Ontario be developed, at one of the three sites mentioned above, to demonstrate the steps required for proven storage including the pilot testing of CO_2 injection. To be achieved in 2025.

5: Reservoir engineering research, development, and demonstration should be supported to determine how to best manage the pressurization of the Cambrian sandstone across Canada during CO_2 injection. To be achieved by 2028.

6: Provincial and federal governments should conduct geophysical exploration of existing faults along the north shore of Lake Erie to detect and characterize basement faults. To be achieved by late 2025.

7: Federal and provincial governments should initiate a public outreach and education programme to inform Ontarians about CCS. To be achieved in 2024.

In conclusion, it is essential, given the goal of 40% CO_2 emissions reduction by 2030, that these seven activities be commenced during FY 2023-4. Achievement dates are premised on the basis of a 4-year pipeline construction schedule and 3 years to develop front-end engineering designs. Failure to (i) commence industrial CCS activities and (ii) accelerate provincial policy and regulatory development in 2023 may result in decarbonization by deindustrialization of parts of the Ontario economy by 2030.

8 CLOSURE

This Road Map has been prepared for the use of those in industry, governments and universities wishing to advance carbon capture and geological storage in SW Ontario. It was prepared with the financial assistance of Natural Resources Canada (NRCan).

Geofirma Engineering Ltd. (Geofirma) has exercised professional judgment in collecting and analyzing the information and in formulating recommendations based on the results of the study. The mandate at Geofirma is to perform the given tasks within guidelines prescribed by the client and with the quality and due diligence expected within the profession. No other warranty or representation expressed or implied, as to the accuracy of the information or recommendations is included or intended in this report.

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Respectfully submitted,

Geofirma Engineering Ltd.

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APPENDIX A

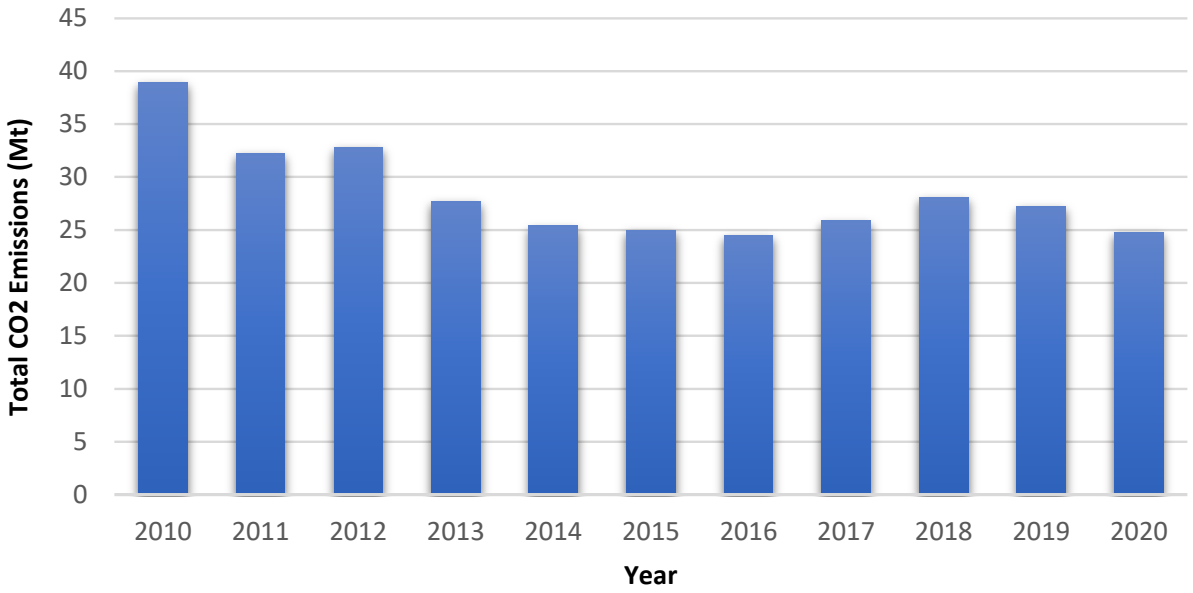
Tables of CO_2 emissions in SW Ontario by industrial sector

APPENDIX A

All data are based on the following resource from Environment Canada:

https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/facility-reporting/data.html

Total Annual CO2 Emissions in SW Ontario from 2010 to 2020 (all sectors and sources)



Note: Starting with the 2017 data collection, the mandatory reporting threshold was lowered from 50 kt CO2 eq. to 10 kt CO2 eq.

Year	Total CO2 Emissions (Mt)
2010	39.0
2011	32.2
2012	32.8
2013	27.7
2014	25.4
2015	25.0
2016	24.5
2017	25.8
2018	28.1
2019	27.2
2020	24.8

2020 CO2 emissions in SW Ontario by industry sector – Total 24.8 Mt

Sector	Number of Emitters	Total CO2 (kt)	% of Total
Manufacturing	116	19,400.1	78.3
Utilities	19	3,777.2	15.2
Greenhouse, nursery and floriculture production	42	781.8	3.2
Education and health care	14	354.8	1.4
Mining and oil and gas extraction	3	235.2	0.95
Waste management and remediation services	28	152.9	0.62
Miscellaneous	4	84.2	0.34
TOTAL	**226**	**24,786.4**	**100%**

Note: Miscellaneous emitters include: Support activities for transportation, Accommodation services, Personal and laundry services, and Defence services.

2020 CO2 emissions in SW Ontario by subsectors of manufacturing – Total 19.4 Mt

Manufacturing Subsector	NAICS Code	Number of Emitters	Total CO2 (kt)	% of Total
Primary metal manufacturing	331	22	7,162.4	36.9
Petroleum and coal product manufacturing	324	6	4,180.9	21.6
Chemical manufacturing	325	28	3,915.3	20.2
Non-metallic mineral product manufacturing	327	13	2,830.6	14.6
Food & beverage manufacturing	311 & 312	21	658.0	3.4
Transportation equipment manufacturing	336	13	488.4	2.5
Other	--	13	164.5	0.8
TOTAL		**116**	**19,400.1**	**100%**

Note: Other subsector includes: Paper (322), Plastic product (326), Fabricated metal product (332), and Furniture and related product (337) manufacturing.

2020 SW Ontario Manufacturing Emitters

Grouped by North American Industry Classification System (NAICS) codes.

331 - Primary Metal Manufacturing (22 emitters, 7,162.4 kt Total CO2)

Company	**Total CO2 (kt)**
3311 - Iron and steel mills and ferro-alloy manufacturing	
ArcelorMittal Dofasco, Hamilton	3,931.5
Stelco, Nanticoke	2,681.1
Stelco, Hamilton	268.5
ArcelorMittal Windsor, Windsor	22.5
Valbruna ASW, Welland	17.8
Gerdau Ameristeel, Cambridge	15.5
3312 - Steel product manufacturing from purchased steel	
Baycoat (Dofasco-Stelco), Hamilton	28.1
Max Aicher, Hamilton	21.7
ArcelorMittal Long Products, Hamilton	19.8
NATT Tools Group, Hamilton	9.2
Welded Tube of Canada, Welland	7.4
3313 - Alumina and aluminum production and processing	
Matalco, Brampton	21.2
Hydro Extrusion Canada, Toronto	16.8
Kaiser Aluminum Canada, London	14.8
Real Alloy Canada, Mississauga	12.9
3314 - Non-ferrous metal (except aluminum) production and processing	
Terrapure BR, Mississauga	16.6
Vale Canada, Port Colborne refinery	15.9
Great Lakes Copper, London	12.3
3315 - Foundries	
Nemak, Windsor aluminum plant	11.0
FCA Canada, Etobicoke casting plant	8.2
Meridian Technologies, Strathroy	5.3
Meridian Technologies, Strathroy Plant E	4.1
TOTAL	**7,162.4**

324 - Petroleum and Coal Product Manufacturing (6 emitters, 4,180.9 kt Total CO2)

Company	**Total CO2 (kt)**
32411 - Petroleum refineries	
Imperial Oil, Sarnia refinery	1,268.0
Imperial Oil, Nanticoke refinery	1,053.4
Suncor Energy, Sarnia refinery	756.9
Shell Canada, Sarnia manufacturing centre	676.5
32419 - Other petroleum and coal product manufacturing	
Petro-Canada Lubricants, Mississauga	404.0
Safety-Kleen Canada, Breslau	22.0
TOTAL	**4,180.9**

325 - Chemical Manufacturing (28 emitters, 3,915.3 kt Total CO2)

Company	**Total CO2 (kt)**
3251 - Basic chemical manufacturing	
NOVA Chemicals, Corunna	939.3
Air Products Canada, Corunna hydrogen facility	582.8
Imperial Oil, Sarnia chemical plant	256.8
Cabot Canada, Sarnia	173.6
Birla Carbon, Hamilton	169.6
Jungbunzlauer Canada, Port Colborne	159.3
Greenfield Global, Chatham	142.6
Suncor Energy, St. Clair ethanol plant	139.1
INEOS Styrolution, Sarnia	126.3
IGPC Ethanol, Aylmer	120.6
Linde Canada, Sarnia CO2 & dry ice plant	35.7
Innophos Canada, Port Maitland	33.3
Greenfield Global, Tiverton	32.7
Rain Carbon Canada, Hamilton	28.6
Zochem ULC, Brampton	9.9
Air Liquide Canada, Hamilton (ASU and H2)	9.8
BIOX Canada, Hamilton	9.5
3252 - Resin and synthetic rubber manufacturing	
NOVA Chemicals, Sarnia	64.0
NOVA Chemicals, Moortown	56.8
Oxy Vinyls Canada, Niagara PVC plant	47.4
ARLANXEO Canada, Sarnia	11.8
3253 - Chemical fertilizer manufacturing	
Terra Intl, CF Industries Courtright nitrogen complex	687.8
3254 - Pharmaceutical and medicine manufacturing	
Apotex, Etobicoke	10.7
Apotex, Toronto	9.4
3259 - Other chemical product manufacturing	
Bartek Ingredients, Stoney Creek Plant #2	25.7
Cytec Canada, Welland plant	15.6
Bartek Ingredients, Stoney Creek Plant #1	9.0
Lanxess Canada, Elmira	7.5
TOTAL	**3,915.3**

327 - Non-metallic Mineral Product Manufacturing (13 emitters, 2,830.6 kt Total CO2)

Company	**Total CO2 (kt)**
3271 - Clay product and refractory manufacturing	
Brampton Brick, Brampton	47.1
3272 - Glass and glass product manufacturing	
O-I Canada, Brampton	68.6
Owens Corning Composite Materials, Guelph	12.0
3273 - Cement and concrete product manufacturing	
CRH Canada (Ash Grove North), Mississauga	888.5
St. Marys Cement, St. Marys	527.8
Federal White Cement, Woodstock	381.7
3274 - Lime and gypsum product manufacturing	
Carmeuse Lime, Dundas	354.7
Carmeuse Lime, Ingersoll	320.3
CGC, Hagersville	74.3
CertainTeed Canada, Mississauga	29.1
3279 - Other non-metallic mineral product manufacturing	
ROXUL, Milton	80.1
Meridian Brick, Aldershot	24.8
Meridian Brick, Burlington	21.6
TOTAL	**2,830.6**

311 & 312 - Food & Beverage Manufacturing (21 emitters, 658.0 kt Total CO2)

Company	**Total CO2 (kt)**
3112 - Grain and oilseed milling	
Ingredion Canada, London plant	128.5
ADM Agri-Industries, Windsor	75.4
Bunge Canada, Hamilton	50.5
3113 - Sugar and confectionery product manufacturing	
Ferrero Canada, Brantford	27.4
3114 - Fruit and vegetable canning, pickling and drying	
Highbury Canco, Leamington	48.4
Sun-Brite Foods, Ruthven	12.1
3115 - Dairy product manufacturing	
Gay Lea Foods Cooperative, Guelph	10.9
Lactalis Canada, Mitchell	10.0
3116 - Meat product manufacturing	
Maple Lodge Farms, Brampton	30.6
Darling International Canada, Moorefield	26.1
Darling International Canada, Dundas	21.8
Sofina Foods, Burlington	17.4
Maple Leaf Foods, Hamilton	15.1
Cargill, Guelph	12.9
3119 - Snack food manufacturing	
Frito Lay Canada, Cambridge	23.8
Super-Pufft Snacks, Mississauga	16.4
3121 - Beverage manufacturing	
Hiram Walker & Sons, Windsor distillery	70.2
Labatt Brewing Company, London brewery	24.0
Molson Coors, Toronto brewery	15.1
Sazerac Distillers, Collingwood distillery	10.9
PepsiCo, Mississauga	10.4
TOTAL	**658.0**

336 - Transportation Equipment Manufacturing (13 emitters, 488.4 kt Total CO2)

Company	**Total CO2 (kt)**
3361 - Motor vehicle manufacturing	
Toyota Manufacturing, Cambridge	81.0
Ford, Oakville assembly complex	64.8
FCA Canada, Brampton assembly plant	62.9
Honda Canada, Alliston	61.7
FCA Canada, Windsor assembly plant	56.5
Toyota Manufacturing, Woodstock	31.0
General Motors, Ingersoll CAMI assembly plant	28.8
3363 - Motor vehicle parts manufacturing	
Magna Exteriors, Guelph	27.9
Magna International, St. Thomas	20.8
Linamar Gear, Guelph	20.2
Vehcom Manufacturing, Guelph	12.2
MSSC Canada, Chatham	11.7
Stackpole International, Stratford	8.9
TOTAL	**488.4**

Other Miscellaneous Manufacturers (13 emitters, 164.5 kt Total CO2)

Company	**Total CO2 (kt)**
322 - Paper manufacturing	
Sonoco, Brantford	23.1
Dunn Paper, St. Catharines	22.9
Hartmann Canada, Brantford	15.5
3M Canada, London	10.7
326 - Plastic product manufacturing	
Canadian General-Tower, Cambridge	13.3
Genpak, Mississauga	11.2
332 - Fabricated metal product manufacturing	
Patriot Forge, Brantford	25.3
MSC, Etobicoke	11.5
Metex Heat Treating, Brampton	10.2
Hendrickson Springs, Stratford	9.3
Kuntz Electroplating, Kitchener	8.7
337 - Furniture and related product manufacturing	
Profile Industries, Toronto	2.0
Spec Furniture, Toronto	0.8
TOTAL	**164.5**

2020 SW Ontario Utility Emitters (19 emitters, 3,777.2 kt Total CO2)

Company	**Total CO2 (kt)**
2211 - Electric power generation, transmission and distribution	
TransAlta, Sarnia cogeneration	1,004.4
Greenfield Energy Centre, Courtright	897.9
Goreway Station Partnership, Brampton power station	472.7
Imperial Oil, Sarnia cogen plant	406.2
Atura Power, Halton Hills generating station	306.2
St. Clair Power, St. Clair energy centre	296.5
Northland Power, Thorold cogen station	200.8
Greenfield South Power, Courtright green electron plant	41.2
Brighton Beach Power, Windsor	23.1
Engie Canada, West Windsor power	17.1
East Windsor Cogeneration, Windsor	10.4
TransAlta Cogeneration, Windsor Essex cogen plant	9.3
2212 - Natural gas distribution	
Six Nations Natural Gas Company, Ohsweken	18.0
22132 - Sewage treatment facilities	
City of Hamilton, Woodward Ave WWTP	14.9
OCWA, G.E. Booth (Lakeview) WWTF	4.7
City of London, Greenway pollution control centre	0.6
22133 - Steam and air-conditioning supply	
London District Energy, London	36.0
Enwave Windsor, Windsor	10.9
Hamilton Utilities, Hamilton energy centre	6.2
TOTAL	**3,777.2**

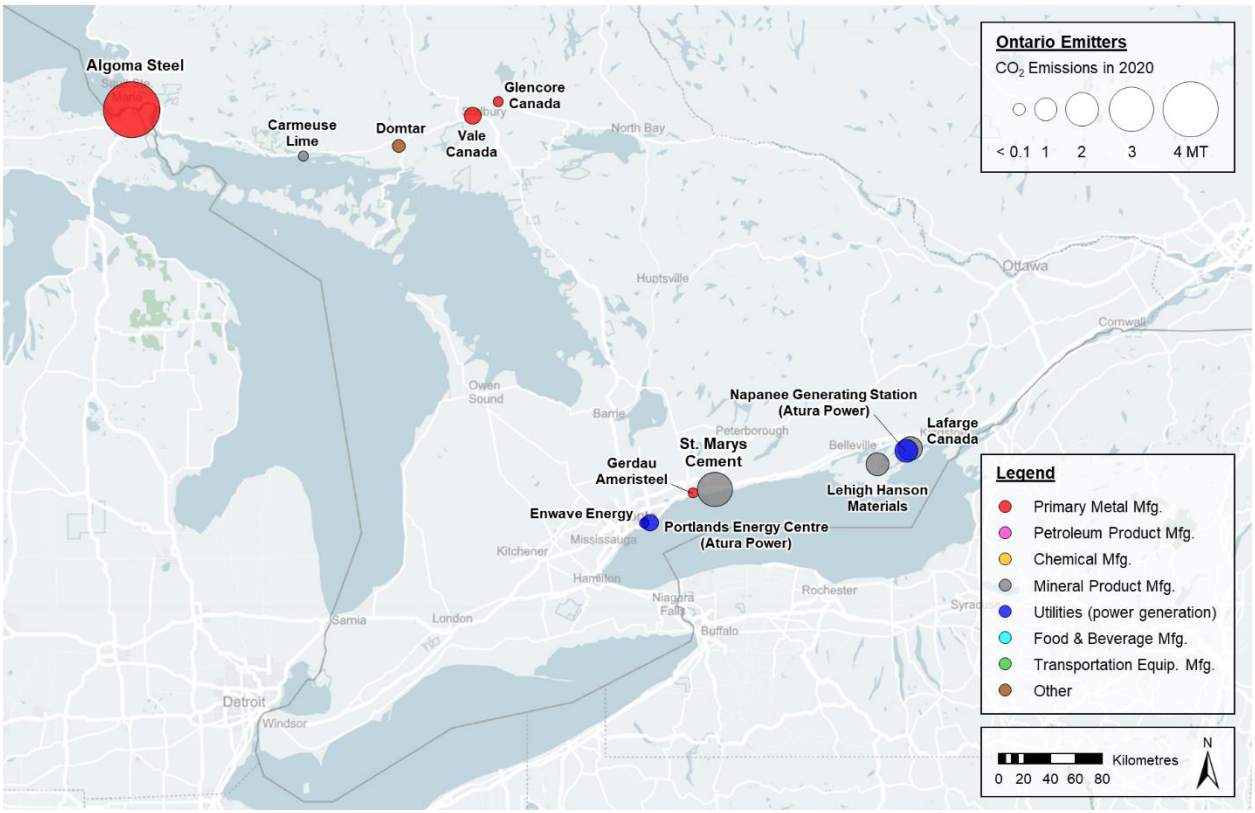
2020 SW Ontario Top Emitters (> 50 kt CO2 - 47 facilities)

Company	Sector	Total CO2 (kt)
ArcelorMittal Dofasco, Hamilton	Primary Metal Mfg.	3,931.5
Stelco, Nanticoke	Primary Metal Mfg.	2,681.1
Imperial Oil, Sarnia refinery	Petroleum Product Mfg.	1,268.0
Imperial Oil, Nanticoke refinery	Petroleum Product Mfg.	1,053.4
TransAlta, Sarnia cogeneration	Utilities	1,004.4
NOVA Chemicals, Corunna	Chemical Manufacturing	939.3
Greenfield Energy Centre, Courtright	Utilities	897.9
CRH Canada (Ash Grove North), Mississauga	Mineral Product Mfg.	888.5
Suncor Energy, Sarnia refinery	Petroleum Product Mfg.	756.9
CF Industries, Courtright nitrogen complex	Chemical Manufacturing	687.8
Shell Canada, Sarnia manufacturing centre	Petroleum Product Mfg.	676.5
Air Products Canada, Corunna hydrogen facility	Chemical Manufacturing	582.8
St. Marys Cement, St. Marys	Mineral Product Mfg.	527.8
Goreway Station Partnership, Brampton power station	Utilities	472.7
Imperial Oil, Sarnia cogen plant	Utilities	406.2
Petro-Canada Lubricants, Mississauga	Petroleum Product Mfg.	404.0
Federal White Cement, Woodstock	Mineral Product Mfg.	381.7
Carmeuse Lime, Dundas	Mineral Product Mfg.	354.7
Carmeuse Lime, Ingersoll	Mineral Product Mfg.	320.3
Atura Power, Halton Hills generating station	Utilities	306.2
St. Clair Power, St. Clair energy centre	Utilities	296.5
Stelco, Hamilton	Primary Metal Mfg.	268.5
Imperial Oil, Sarnia chemical plant	Chemical Manufacturing	256.8
Northland Power, Thorold cogen station	Utilities	200.8
Cabot Canada, Sarnia	Chemical Manufacturing	173.6
Plains Midstream Canada, Sarnia fractionation plant	Oil & Gas Extraction	170.8
Birla Carbon, Hamilton	Chemical Manufacturing	169.6
Jungbunzlauer Canada, Port Colborne	Chemical Manufacturing	159.3
Greenfield Global, Chatham	Chemical Manufacturing	142.6
Suncor Energy, St. Clair ethanol plant	Chemical Manufacturing	139.1
Ingredion Canada, London plant	Food & Beverage Mfg.	128.5
INEOS Styrolution, Sarnia	Chemical Manufacturing	126.3
IGPC Ethanol, Aylmer	Chemical Manufacturing	120.6
Emerald Energy From Waste, Brampton	Waste Management	88.9
Toyota Manufacturing, Cambridge	Transportation Equip. Mfg.	81.0
ROXUL, Milton	Mineral Product Mfg.	80.1
ADM Agri-Industries, Windsor	Food & Beverage Mfg.	75.4
CGC, Hagersville	Mineral Product Mfg.	74.3
Hiram Walker & Sons, Windsor distillery	Food & Beverage Mfg.	70.2
O-I Canada, Brampton	Mineral Product Mfg.	68.6
Ford, Oakville assembly complex	Transportation Equip. Mfg.	64.8
NOVA Chemicals, Sarnia	Chemical Manufacturing	64.0
FCA Canada, Brampton assembly plant	Transportation Equip. Mfg.	62.9
Honda Canada, Alliston	Transportation Equip. Mfg.	61.7
NOVA Chemicals, Moortown	Chemical Manufacturing	56.8
FCA Canada, Windsor assembly plant	Transportation Equip. Mfg.	56.5
Bunge Canada, Hamilton	Food & Beverage Mfg.	50.5

2020 Other Large Southern Ontario Emitters (> 100 kt CO2 - 12 facilities)

The following emitters are outside the designated SW Ontario study area.

Company	Sector	Total CO2 (kt)
Algoma Steel, Sault Ste. Marie	Primary Metal Mfg.	3,858.5
St. Marys Cement, Bowmanville cement plant	Mineral Product Mfg.	1,469.9
Lafarge Canada, Bath cement plant	Mineral Product Mfg.	695.0
Atura Power, Napanee generating station	Utilities	637.4
Lehigh Hanson Materials, Picton cement plant	Non-metallic minerals	636.3
Vale Canada, Copper cliff smelter	Primary Metal Mfg.	346.7
Autura Power, Portlands energy centre	Utilities	326.3
Domtar, Espanola paper mill	Paper Manufacturing	202.0
Gerdau Ameristeel, Whitby mill	Primary Metal Mfg.	123.1
Glencore Canada, Sudbury nickel smelter	Primary Metal Mfg.	122.8
Enwave Energy, Toronto steam plant	Utilities	119.6
Carmeuse Lime, Blind River operations	Mineral Product Mfg.	117.1



APPENDIX B

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APPENDIX C

Workshop Report: Geological CO_2 Storage in Ontario: Addressing Regulatory Uncertainties, by Professor Neil Craik, October 2022

Geological CO_2 Storage in Ontario: Addressing Regulatory Uncertainties

Workshop Report

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Waterloo, ON, Canada

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Introduction

On October 13, 2022, a workshop entitled "Geological CO_2 Storage in Ontario: Addressing Regulatory Uncertainties" was held at the Balsillie School of International Affairs. The Workshop was organized by the Waterloo Institute for Sustainable Energy with the intention of initiating a dialogue among industrial carbon dioxide (CO_2) emitters in Southern Ontario and legal and policy experts inside and outside the government on pathways for implementing carbon capture and storage (CCS) to reduce industrial emissions in the province. The Workshop was co-chaired by Neil Craik, Professor of Law, School of Environment, Enterprise and Development and the Balsillie School of International Affairs, University of Waterloo; Maurice Dusseault, Professor of Geological Engineering, Department of Earth and Environmental Sciences, University of Waterloo, and Richard Jackson, Geofirma Engineering and Adjunct Professor, Department of Earth and Environmental Sciences, University of Waterloo.

Approximately 45 participants attended the Workshop, including representatives from most of the sectors that account for significant industrial CO_2 emissions in Southern Ontario, as well as observers from the Province of Ontario. The workshop was held under the Chatham House Rule (requiring that participants not attribute statements at the Workshop to speakers or participants), to promote a candid exchange.

The motivation for the workshop was the release of a proposal by the Ontario Ministry of Northern Development, Mines, Natural Resources and Forestry that would introduce legislative changes in Ontario that would remove the current prohibitions on subsurface storage of carbon dioxide.[1] While the proposed changes would remove certain legal barriers to permanent carbon sequestration, commercial-scale storage would likely require the development of a comprehensive regulatory framework. This framework would address such matters as the requirements for long-term management of carbon dioxide, including monitoring, potential future liabilities, and the property rights associated with sequestration. The focus of the Workshop was identifying the regulatory elements necessary to facilitate the scaled implementation of CCS in Southern Ontario.

The workshop was divided into six sessions:

- Introduction/Background/Context
- Industry Perspectives on CCS
- Lessons from Alberta's CCS Implementation Experiences
- Development Issues
- Legal Issues
- Open Discussion

[1] Ontario Ministry of Northern Development, Mines, Natural Resources and Forestry. (2022, January 11) *Discussion Paper: Geologic Carbon Storage in Ontario.*

This Workshop Report adopts the structure of the workshop and provides a summary of the key points discussed in each session. In keeping with the Workshop rules, attribution of statements in this Report are made with the consent of the speaker.

Context

The starting point for discussing CCS in Southern Ontario is recognizing the significant challenge that reducing emissions from major industrial sources poses for the Province. Emissions from Ontario total approximately 166 Mt CO_2 eq/year[2]; 27% of those emissions, or 45 Mt CO2 eq, come from industrial sources that use fossil-fuel-based energy or those, like cement or lime production, that produce process emissions.[3] Opportunities to either reduce these emissions through energy conservation or switch to a renewable energy source are limited and will likely take significant time to implement. Carbon capture, utilization and storage will likely be required to address a significant portion of these emissions.

There are several concentrations of emission sources in Southern Ontario, including the Sarnia area, Hamilton and Nanticoke (see *Figure 1*). Locating emission sources close to storage sites or existing pipelines reduces the costs of transporting CO_2 to injection sites, which would otherwise require the construction of new pipelines.

Figure 1. Major sources of CO_2 emissions in Southern Ontario.[4]

[2] Megatonnes (million metric tonnes) of CO2 equivalent per year.
[3] Environment and Climate Change Canada. (2020). *National inventory report: greenhouse gas sources and sinks in Canada.* Ottawa, ON: Environment Canada.
[4] Environment and Climate Change Canada. (2021). *Facility-reported greenhouse gas data* [Map]. Government of Canada

Switching from the demand side to the supply side of the CCS equation, it is important to consider the limited volume of suitable subsurface storage in the Southern Ontario region. Stable and permanent CO_2 storage is situated at depths greater than 800 metres in strata that have suitable permeability for injection. In Southern Ontario, thin Cambrian-age sandstone formations provide accessible pore volume, but depending on injection strategy, several factors may limit the pore volume that will ultimately be accessible.[5] Preliminary assessments have identified areas located along the north shore of Lake Erie that have storage potential (see *Figure 2*). However, there is a significant need to engage in further technical assessments of suitable areas to estimate the storage volumes available near the major emitters in Southern Ontario.

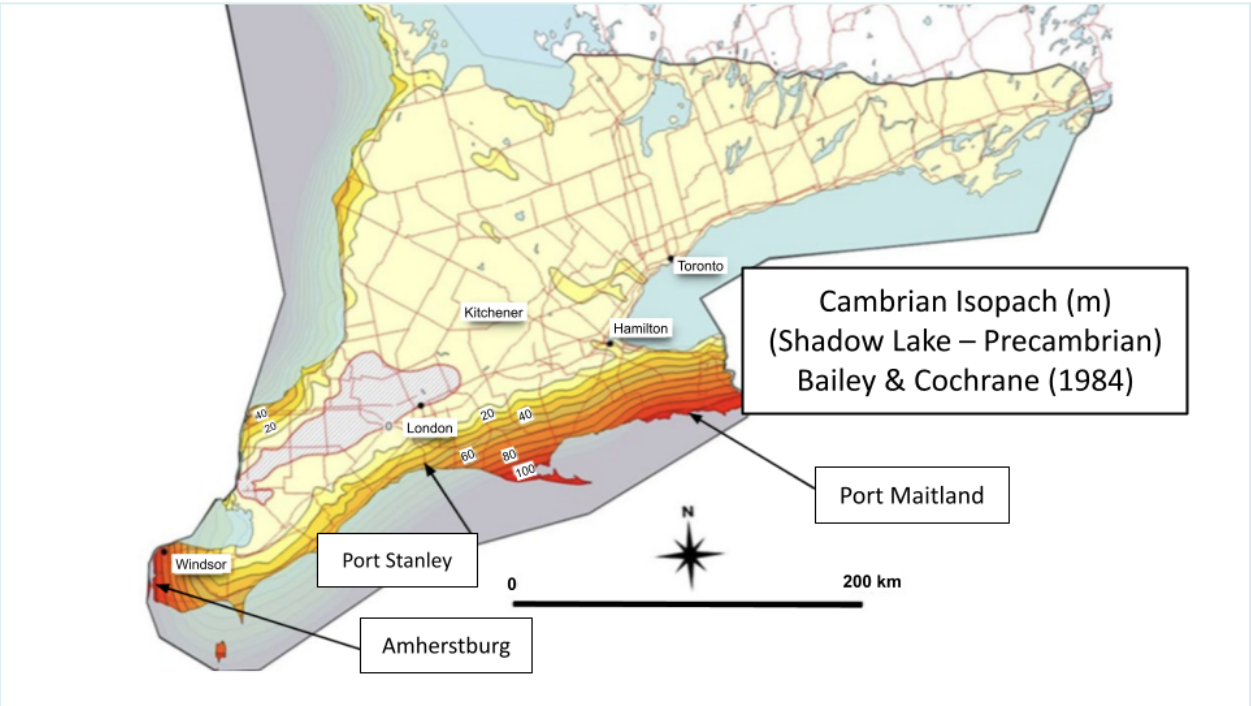

Figure 2. Thickness of the saline Cambrian sandstone aquifer in meters beneath southern Ontario. Three sites are identified that are potentially suitable for geological CO2 storage. Figure prepared by Bruce Hart, Western University, sites identified by Dick Jackson, Geofirma Engineering.[6]

At the current time, the *Oil, Gas and Salt Resources Act* (OGSRA) prohibits the injection of CO_2 for the purposes of carbon sequestration.[7] The proposed changes to the OGSRA would remove the prohibition so that it would allow for permanent CO_2 storage.[8] The proposed legislative changes would also modify a prohibition under the Mining Act that prevents the permanent storage of CO_2 under a lease issued by the Minister on Crown land.[9] The Discussion Paper outlining the potential

[5] These factors include gravity override, viscous fingering, heterogenous channelling and capillary blockage.
[6] Bailey Geological Services Ltd. and Cochrane, R.O. (1984). *Evaluation of the conventional and potential oil and gas reserves of the Ordovician of Ontario.* Ministry of Natural Resources, Ontario Geological Survey.
[7] *Oil, Gas and Salt Resources Act*, R.S.O. 1990, c.P.12, s. 11(1.1).
[8] Ontario Ministry of Natural Resources and Forestry. (2022, November 23). *Proposed amendments to the Oil, Gas and Salt Resources Act, to remove the prohibition on carbon sequestration.* ERO number 019—6296.
[9] *Mining Act*, R.S.O. 1990, c.M.14, s. 101.1(2).

legislative changes acknowledges that these steps would be necessary but insufficient to regulate and manage carbon storage in Ontario.[10]

Industry Perspectives

The development of CCS in Ontario is expected to be a key component of the pathway to net-zero/emissions reduction for large-scale industrial emitters in Ontario. Understanding the needs of industries will be an important element of the regulatory development process. Key insights delivered by industry representatives on CCS development pathways were as follows:

- Demand: For several industries, CCS is viewed as an essential mitigation pathway. Energy efficiency, switching to alternative fuels (such as hydrogen), and process modernization are also critical emission reduction elements, but there will remain significant emissions, particularly process emissions, for which there are no alternative measures, other than CCS. It was noted that producing "blue" hydrogen, the most common and cost-efficient means of producing hydrogen, itself requires natural gas combined with CCS.
- Technological readiness: new technologies may provide alternative (to CCS) pathways to decarbonization, but these will not be available in the short to medium term. CCS is recognized as a more mature technology that provides an interim/transition pathway on a 20-to-30-year time horizon. CCS is viewed as a "safe bet" for hard-to-abate industries such as cement and steel (relative to other decarbonization strategies).
- Utilization: carbon utilization applications, other than EOR,[11] are currently niche and are not realizable at the scales required to meet the necessary level of reduction. Carbon utilization markets may emerge, but markets at scale are more likely to be a post-2050 phenomenon.
- Scale of Challenge: several commentators identified significant barriers to large-scale CCS implementation that currently exist, including the need for shared CO_2 transportation infrastructure (pipelines); the fact that existing emitting facilities do not have room to accommodate capture retrofits; uncertainty surrounding carbon storage site capacity; and the need for a significant amount of lead time for necessary site characterization studies.
- Incentives: financial incentives that address high capital and operating expenses are critical for deployment. The proposed federal investment tax credit may be insufficient. Some industry representatives believe that the higher degree of government investment in CCS in the U.S. (through the 45Q tax credit) will affect the

[10] Ontario Ministry of Northern Development, Mines, Natural Resources and Forestry. (2022, January 11) *Discussion Paper: Geologic Carbon Storage in Ontario*. p.6.
[11] EOR - Enhanced oil recovery through injection of CO2 to thin and displace remnant oil in largely depleted reservoirs to producing wells.

competitiveness of Ontario-based industries. Long-term certainty on how long the tax credit will be available is an important consideration in investment decisions.
- Collaboration: collaboration among industry actors is crucial for developing regional CCS hubs, shared infrastructure, and creating economies of scale.
- Urgency: significant lead times (8 to 10 years) are needed for implementing CCS. There is a need to begin to initiate actions, such as storage site characterization studies, in the short term. Creating regulatory certainty is a necessary precondition for investment.

The View from Alberta

Considering the much more advanced development of CCS regulation in Alberta, Professor Nigel Bankes, Professor Emeritus at the University of Calgary Law School, was invited to provide an overview of Alberta's legal and regulatory framework, identifying potential lessons for Ontario. The workshop also received further operational insights from a speaker familiar with Alberta's ongoing CCS development process.

Professor Bankes noted that several conditions have contributed to the development of CCS in Alberta, including having geology that allows for large amounts of carbon storage and the high demand for CCS from the oil and gas sector, as well as other large-scale emitters. From a regulatory standpoint, the development of the CCS regulatory framework was aided by the Alberta Energy Regulator's experience as a regulator of the oil and gas sector,[12] subsurface disposal of acid gas,[13] and enhanced oil recovery. An important stage in the development of Alberta's CCS regime was the 2013 Regulatory Framework Assessment process, an expert-informed process that made recommendations for the development of a regulatory framework for CCS.[14]

The regulatory framework, particularly as it relates to carbon storage, encompasses four central issues: property rights and ownership; permitting of injection/storage sites; issues related to liabilities associated with stored carbon; and carbon crediting issues.

In addressing the question of ownership of sub-surface storage (pore space), section 15.1 of the *Mines and Minerals Act* (2010) vests the ownership of the pore space below the surface of all land in

[12] "Today, the AER [Alberta Energy Regulator] is the single regulator of energy development in Alberta—from application and exploration, to construction and operation, to decommissioning, closure, and reclamation." The AER is regarded as the "father" of provincial energy regulatory bodies in Canada. Alberta Energy Regulator. (2022). *About the AER: Who we are.*
[13] The term acid gas refers to the high acidity of the aqueous solution of certain water purification waste gases (water vapor, CO2, SOx, H2S) in process water. Acid gas may be disposed by direct injection or co-mingled with waste water from oil and gas production.
[14] Alberta Energy. (2013). *Carbon Capture & Storage: Summary report of the regulatory framework assessment.* Alberta Open Government Program. Alberta Energy: Electricity and Alternative Energy and Carbon Capture and Storage Division.

Alberta in the provincial Crown.[15, 16] The result is a unity of ownership of pore space in the Provincial government, regardless of the ownership of the mineral estates. This ownership model facilitates carbon storage by placing control of pore space in the hands of the government and relieves developers of carbon storage projects from having to acquire sub-surface interests from multiple parties.

The scheme for the acquisition of storage space is established under Part 9 of the Mines and Mineral Act and the Carbon Sequestration Tenure Regulations, which creates two types of legal interests that may be acquired: evaluation permits and sequestration leases. An evaluation permit, issued by the Minister, grants to the permit holder the:

> "right to conduct evaluations and testing, including the drilling of wells and injection of substances as approved by the Regulator, into deep subsurface reservoirs within the location of the permit to evaluate the geological or geophysical properties of the deep subsurface reservoirs for the purposes of determining their suitability for use for the sequestration of captured carbon dioxide."[17]

The term of the evaluation permit is five years and can include an area of up to 73,728 hectares. The evaluation permit must be accompanied by a "monitoring, measurement and verification plan," as described in the regulations.[18]

A person may also apply for a carbon sequestration lease, which grants "the right to drill wells, conduct evaluation and testing and inject captured carbon dioxide into deep subsurface reservoirs within the location of the lease." To receive a lease, the applicant provides evidence that the location is suitable for the sequestration of carbon dioxide and must be accompanied by a monitoring, measurement, and verification (MMV) plan, as well as a closure plan. Sequestration leases are for 15-year terms, which may be renewed. The lease area has a similar extent as the evaluation permit, but an applicant may seek multiple leases. The closure plan provides information on the total quantity of carbon dioxide injected and an evaluation of the CO_2 plume and associated pressure front; the plan is required to be renewed every three years.

In addition to the leasing requirements, Alberta has a separate approvals process under the Oil and Gas Conservation Act which requires the operator to receive well licenses and scheme approval. These approvals are subject to existing regulatory directives that are not CCS-specific. For example, Alberta applies existing acid gas regulatory directives to CO_2 projects. As part of the scheme approval, the applicant must satisfy the Alberta Energy Regulator's requirement that the injection of CO_2 will not interfere with the recovery or conservation of oil and gas.

The liability structure in Alberta provides that the lessee/licensee is responsible for any liabilities associated with loss of containment, whether those liabilities arise from statutory duties or from

[15] *Mines and Minerals (Coalbed Methane) Amendment Act*, 2010, S.A.2010, c.20, s. 15(1).
[16] Pore space is the aggregate of non-mineral porosity in a rock, occupied by water, gas or oil.
[17] *Carbon Sequestration Tenure Regulation*, Alta Reg 68/2011, s. 3(3).
[18] Ibid. 3(2).

duties owed to third parties (tort) during the operational phase of the project. Upon closure, the lessee can transfer liabilities to the provincial government. The transfer is effectuated by a closure certificate issued by the government, where the government is satisfied that the lessee has met its statutory obligations and is in receipt of evidence that the plume is acting in a stable and predictable manner. There is a closure period of ten years (from the end of operations until the Crown accepts the transfer). Upon transfer, the Crown assumes ownership and responsibility for tort and statutory liabilities associated with the injected CO_2. The Crown's acceptance of liability is supported by a Post-Closure Stewardship Fund, into which licensees pay. The Fund can be accessed by the government to address statutory obligations, but not for third-party tort liability claims.

Crediting is governed by provincial carbon regulations (Technological Innovation and Emissions Reduction (TIER) Regulation), which provide that CCS projects are eligible to generate offset credits.[19] Credits may be generated from both sequestration and capture of CO_2, resulting in double crediting.[20]

Shell's Quest project, in operation since 2015, provides the best example of the application of the regulatory scheme to an ongoing project. The project had total project costs of $1.35 billion, with significant government support ($745 million from Alberta, and $120 million from Federal Government). To date, the Quest project has sequestered over 7 million tonnes of CO_2; approximately one million tonnes each year.

There was further discussion on current developments in Alberta; namely, the development of the Alberta Carbon Trunk Line and the government's request for "carbon sequestration hub" proposals. Unlike the Quest project, which followed a vertically integrated model in which the company was responsible for capture, transport, and sequestration, the hubs will provide shared, centralized transport and storage infrastructure. This process provides an alternative model for regulating access to pore space. One key area of difference between the regime used for Quest and the unfolding hub request for proposal (RFP) process is the potential to enter into Ministerial agreements under s.9 of the *Mines and Minerals Act*, which provides high degrees of discretion to the government and may result in less transparency regarding the process.[21]

Alberta has also benefited from attaching knowledge sharing requirements to funding agreements, which makes publicly accessible information on design, risk assessment, MMV, and operating reliability.

The workshop also heard from CCS project development experts operating in US jurisdictions, with a focus on Indiana. A favourable policy and regulatory environment has proved to be a key factor for successful CCS implementation, with some states now actively trying to attract CCS investment. This provides an alternative regulatory model as pore space in relevant state jurisdictions remains privately owned. Therefore, project developers must acquire subsurface

[19] *Technology Innovation and Emissions Reduction Regulation*, Alta Reg 133/2019.
[20] The extent of double crediting is tied to the carbon price set under the regulation [TIER Reg, s. 19(3)].
[21] *Mines and Minerals Act*, RSA 2000, c.M.17, s. 9.

rights from multiple private owners through individual negotiations. Landowners are compensated through lease arrangements. In Indiana, the CCS framework (House Bill 1209) vests pore space ownership in the surface estate owner. Some states have unitization rules which allow access to pore space despite non-consenting owners. Indiana provides for liability transfer upon project completion, with a state fund to support monitoring and management. Statutory limitations to liability have also been established. For example, subsurface trespass is not actionable unless it results in impacts to health or direct physical injury.

Injection wells are regulated federally (by U.S. Environmental Protection Agency) through the Underground Injection Control program, which includes a distinct carbon sequestration class of wells (Class VI). The regulatory aim of Federal regulation is protecting groundwater, a significant source of drinking water. Operators must demonstrate the adequacy of the injection zone. Federal regulation also establishes key geological and operational requirements, as well as post-closure requirements for monitoring.

Legal and Policy Issues in Ontario

The proposed changes to the *OGSRA* and *Mining Act* remove regulatory prohibitions against CCS, but do not address threshold questions concerning who owns pore space in Ontario and what the mechanisms are for acquiring property rights. Nor do the proposed changes address key regulatory issues surrounding regulatory approvals for sequestration operations and liabilities associated with stored CO_2 and how the CO_2 that is sequestered will be credited within Ontario's greenhouse gas emission reduction requirements. While these issues will be determined through future policy decisions made by the Ontario government, there are existing baseline rules and analogous areas of regulation that may provide models for CCS regulation.

In the absence of specific statutory provisions addressing pore space ownership, the question of ownership will be determined by common law property requirements, as modified by legislation. The baseline rule in Ontario is that land ownership in fee simple includes ownership of sub-surface estates, which would include pore space.[22] Subsurface rights can be severed from the surface estate through legislation (for example, reserving mineral rights to the Crown), or through specific reservations or grants. In Ontario, where much of the lands are privately owned, mineral rights may be reserved by the Crown, but most subsurface rights are privately held. One area of interest for carbon storage due to favourable geology is beneath Lake Erie, which would be owned by the Crown.[23] In cases where there has been no severance of a subsurface estate, the pore space is clearly owned by the landowner.

In cases where the mineral estate has been severed, there is some ambiguity as to whether the owner of a mineral estate in Ontario also owns the right to use the pore space for storage

[22] *Case of Mines* (1568), 1 Plowden 310, 75 ER 472.
[23] *Beds of Navigable Waters Act*, R.S.O. 1990, c.B.4.

purposes. In other words, the owner of the mineral estate may have the right to remove minerals, but not necessarily to store materials or otherwise use the subsurface. There is a line of cases that suggests that storage rights need to be acquired from the holder of the mineral estate, sometimes referred to as the "English Rule."[24] Others have suggested that the mineral estate does not include the right to control the use of the subsurface for storage.[25] The law in Ontario is not clear and, in the absence of clarification, may complicate the acquisition of storage rights.

Acquisition of storage rights, if owned by the Crown, will likely be governed by storage leases as contemplated by section 101.1 of the *Mining Act* (which, as noted, is one of the statutory provisions that is proposed to be amended to facilitate carbon storage.)[26] Private interests may be acquired through a lease, similar to existing gas storage leases, although the specific terms and nature of the interest may be complicated by the permanence of the storage and associated liability issues. Other jurisdictions, as discussed above, have tended to create separate and sequential interests for the purposes of site evaluation and subsequent storage.

Further direction may also be necessary to address the extent of the interests that must be acquired, as the injection of CO_2 will impact subsurface conditions beyond the storage area. The size of lease areas under the Alberta regime is of a much larger scale than any sub-surface lease areas associated with current activities in Ontario. The need to acquire private interests from multiple owners raises the issue of whether there will be a need for compulsory pooling and unitization. Ontario has experience with compulsory pooling under the gas storage regime, with the Ontario Energy Board empowered to establish compensation formulas. A final area that will likely need to be addressed is the allocation of pore space, which may be a limited resource in Ontario.

Among the regulatory issues raised was the prohibition on the injection of carbon for the purpose of enhanced oil recovery under the proposed amendments to the *Oil, Gas and Salt Resources Act*. It was noted that the prohibition on EOR restricts the already small number of potential storage sites in Ontario. Moreover, there may be a small net emissions reduction in CO_2 storage associated with EOR.[27]

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[24] *Little v Western Transfer and Storage Company* (1922), 69 D.L.R. 364 (Alta SC TD).
[25] Barton, B. (2014). "The Common Law of Subsurface Activity: General Principles and Current Problems." In Zillman, D. N., McHarg, A., Barrera-Hernández, L. K., & Bradbrook, A. J. (Eds.), *The law of energy underground: understanding new developments in subsurface production, transmission, and storage.* (1st ed., pp. 21-36). Oxford University Press, USA.
[26] *Mining Act*, R.S.O. 1990, c.M.14, s.101.1.
[27] At the time of the workshop, the proposed changes would continue to prohibit CO2 storage for enhanced oil recovery (EOR), but in a subsequent announcement, the Ontario government has proposed that the removal of the prohibition apply to EOR, as well. Ontario Ministry of Natural Resources and Forestry. (2022, November 23). *Proposed amendments to the Oil, Gas and Salt Resources Act, to remove the prohibition on carbon sequestration.* ERO number 019—6296.

Another analogous regulatory area that may yield valuable lessons is the recently adopted regime for compressed air energy storage projects.[28] Here the regime draws on existing technical standards for well licensing and storage that may provide models for CCS. Other recent regulatory processes of relevance include the long-term geological storage of nuclear waste, which raises similar issues concerning the maintenance of public confidence over long periods. Environmental assessments could play an important role here.

Current approaches to addressing liability for environmental matters are not a good fit for geological storage of CO_2 given the very long-time frames involved, which may exceed the lifetimes of the site lessee/licensee.

Several speakers raised the importance of indigenous consultation, which is structured by the constitutional duty to consult and, where appropriate, accommodate, Indigenous communities whose s.35 rights are potentially impacted by projects.[29] This will likely require proactive outreach to First Nations and the potential creation of economic opportunities for affected communities.

The current provincial output-based emissions performance standards do not account for captured emissions, which would still be covered by pricing requirements; this highlights a need to adjust emissions standards to net out captured and sequestered carbon. Additionally, the existing carbon emission regime does not incorporate credit provisions, which may be necessary to facilitate investment. Voluntary markets may provide an alternative avenue for investment, although the integration of offsets into the formal emissions regulatory scheme is understood as key in Alberta.

Finally, the speakers considered the broader question of potential pathways toward a scaled-up CCS regime serving southern Ontario. Here it was noted that the process in Alberta was strongly influenced by an organized network of industry actors representing key emission sectors in the province–referred to as the Integrated CO_2 Network (ICO2N). This coordinated approach was a critical catalyst for the Alberta Carbon Trunk Line and would be a model worth considering for southern Ontario.

Closing Discussion

The workshop ended with an open discussion of key issues. The key points raised in this discussion were as follows:

- In light of carbon pricing pressures and the long lead time to implement CCS, there is a need to consider options for the transportation of carbon dioxide to storage sites out-of-province.

[28] *Exploration, Drilling and Production Regulation*, O. Reg. 245/97.
[29] *Constitution Act*, 1982, Schedule B to the *Canada Act* 1982 (UK), 1982, c. 11, s. 35.

- Industry mobilization was raised as an important step in moving forward, with discussion of the prospects of developing a network organization along the lines of ICO2N.
- Proactive public education and consultation were identified as other key steps in moving forward. Transparency and inclusiveness in the process are important goals.
- Pore space availability in Ontario is a key technical uncertainty that needs to be resolved.
- Urgency and the competitiveness implications of failing to address industrial emissions were recurring points raised.

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