Scoping the Commercial Potential for **Carbon Capture, Utilization and Storage in Ontario** to 2035

Report 1 of the Ontario Hydrogen Foundation Studies




2023

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An Initiative of H2GO Canada

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PREFACE

The Ontario Hydrogen Foundation Series

H2GO Canada is pleased to present this report, which is the first in a series of **Ontario Hydrogen Foundation Studies**. *Scoping the Commercial Potential for Carbon Capture, Utilization and Storage in Ontario* has been developed as both an educational resource and an analytical work. It synthesizes and summarizes information about the technologies of carbon capture and the systems of storage that are prospectively available to Ontario as means of fulfilling its greenhouse gas emissions reductions goals for 2030 and by mid-century, as part of a broader and more comprehensive plan. The analysis involves a geospatial assessment of where carbon capture and storage opportunities appear promising in Ontario within a 2035-time horizon. Hydrogen plays an integral role in many systems of carbon capture and utilization, and its temporary storage in suitable subsurface repositories shares some characteristics with permanent underground storage of carbon dioxide, often in similar geological formations and parts of the province. The overlap in these two areas of study (of carbon and of hydrogen storage) defines the scope of this report.

H2GO Canada - background

H2GO Canada is a Not-for-Profit organization that was established in 2018 to advance a vision of hydrogen becoming a fully developed, low-carbon energy pathway for heat, power and mobility in Canada, as well as for de-carbonizing industrial production, supported by commercially vibrant supply chains. Its mission is to help make hydrogen systems a practical option for organizations in Canada that are seeking to reduce greenhouse gas emissions within their operations. Accordingly, the work of the organization focuses on cultivating conditions for hydrogen markets to develop, grow and thrive.

In 2019, H2GO Canada released its first report, *Developing a Sustainable Approach to Hydrogen Deployment in Canada*, as the product of a cross-Canada process of consultation with large employer organizations representing the primary sectors of the national economy. The policies and investment decisions of such organizations will determine in significant part the future of hydrogen systems adoption and expansion in Canada, simply as a matter of their importance and leverage within energy and material supply chains throughout the country. Input from this community-of-interest informed the seven guiding principles of hydrogen strategy development in Canada, set forth in H2GO Canada's inaugural report:

1. Prioritize a **net gain** in employment
2. Be guided by **analytical rigour**, basing deployment decisions on full life cycle analysis of sustainability criteria
3. Focus on the **development of markets** to accelerate scale-up
4. Build on international leadership to **secure growth in exports of technology**, services and expertise
5. Use hydrogen to help mobilize **Canada's resources for export**
6. Showcase the application of hydrogen to **integrated community energy system** design
7. Deliver **clean air** benefits to the public

These principles guided the development of the study presented herein.

Informal advisory group

H2GO Canada reached out to members of its community-of-interest and invited them to review the progress of the study team during the course of its work to produce this report. Representatives of industrial sectors with active operations in Ontario, as well as subject matter experts, generously contributed their time and talent as an informal advisory group. Sectors represented included steel, cement, chemicals, petrochemicals, mining, energy, transportation and logistics. The insights and expertise of the advisory group members enriched the analysis carried out by the study team assembled by H2GO Canada, and helped to ensure that the content of this report is relevant to the needs of the principal stakeholders.

Study Team

A team of technical professionals was assembled and retained by H2GO Canada to produce this report. Notably, Change Energy Services – an engineering consultancy based in Oakville, Ontario – made a significant dedication of in-kind support to the study, without which the geospatial analysis and map generation would not have been possible.

Special guidance and assistance were provided by the Gasification and Fluidized Bed Combustion Team at CanmetENERGY under the leadership of Dr. Robin Hughes, and by Dr. Dru Heagle with the Sub-Surface Environment Team. Access to the Open Source Tools provided under the *National CCUS Assessment Framework* were instrumental to the completion of the study.

I am confident that this report will serve as a fulsome introduction to the issue of carbon capture, utilization and storage, as well as surface and subsurface storage of hydrogen, as viewed through a lens focusing on the challenge of decarbonizing Ontario’s economy. Through the presentation of background research and the analyses visualized as maps, H2GO Canada hopes that this report will provoke important dialogue and help to prime stakeholders for meaningful engagement in the development of relevant public policy.

Sincerely,

Bob Oliver
President and Member of the Board of Directors, H2GO Canada

ACKNOWLEDGEMENTS

The production of this report was made possible by the financial support of the following organizations, for which H2GO Canada expresses its gratitude.

H2GO Canada also gratefully recognizes the support and guidance from CanmetENERGY and of John Avis and Dr. Richard Jackson at Geofirma Engineering Ltd., for their insight and advice, and for referring the study team toward key information resources. Our thanks to Adam White and the team at Powerconsumer for their valued input to the study team's considerations on electricity grid supply scenarios, and to Isadore Day, Wiindawtegowinini of Bimaadzwin for his perspectives on engagement of Indigenous communities and Indigenous-led enterprise.

This report was researched and written by Bob Oliver at H2GO Canada and by Allan Davidson and Gupar Kaur Punia at Change Energy Services. The geospatial analysis and maps were developed by G. Rymal Smith, Cheryl Robinson and Gupar Kaur Punia, and report editing and formatting by Heather Lindsay, at Change Energy Services.

The views expressed in this publication are the views of H2GO Canada and do not necessarily reflect those of any parties identified herein.

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EXECUTIVE SUMMARY

The production of iron and steel, lime and cement, and chemicals and petrochemicals are anchors of Ontario's economy and represent industrial capacity of strategic importance to Canada. However, these industries are also major emitters of carbon dioxide. The fuel-switching solutions that work in other sectors, such as in transportation and buildings, often do not apply to industrial facilities. Instead, carbon capture, utilization and storage (CCUS), which encompasses a suite of established and emerging technologies and processes, can help to fulfill the deep decarbonization objectives of the province's emissions-intensive, trade-exposed industry sectors. Developing Ontario's CCUS capacities is, therefore, central to its long-term competitiveness and to the Pan-Canadian Framework on Clean Growth and Climate Change.

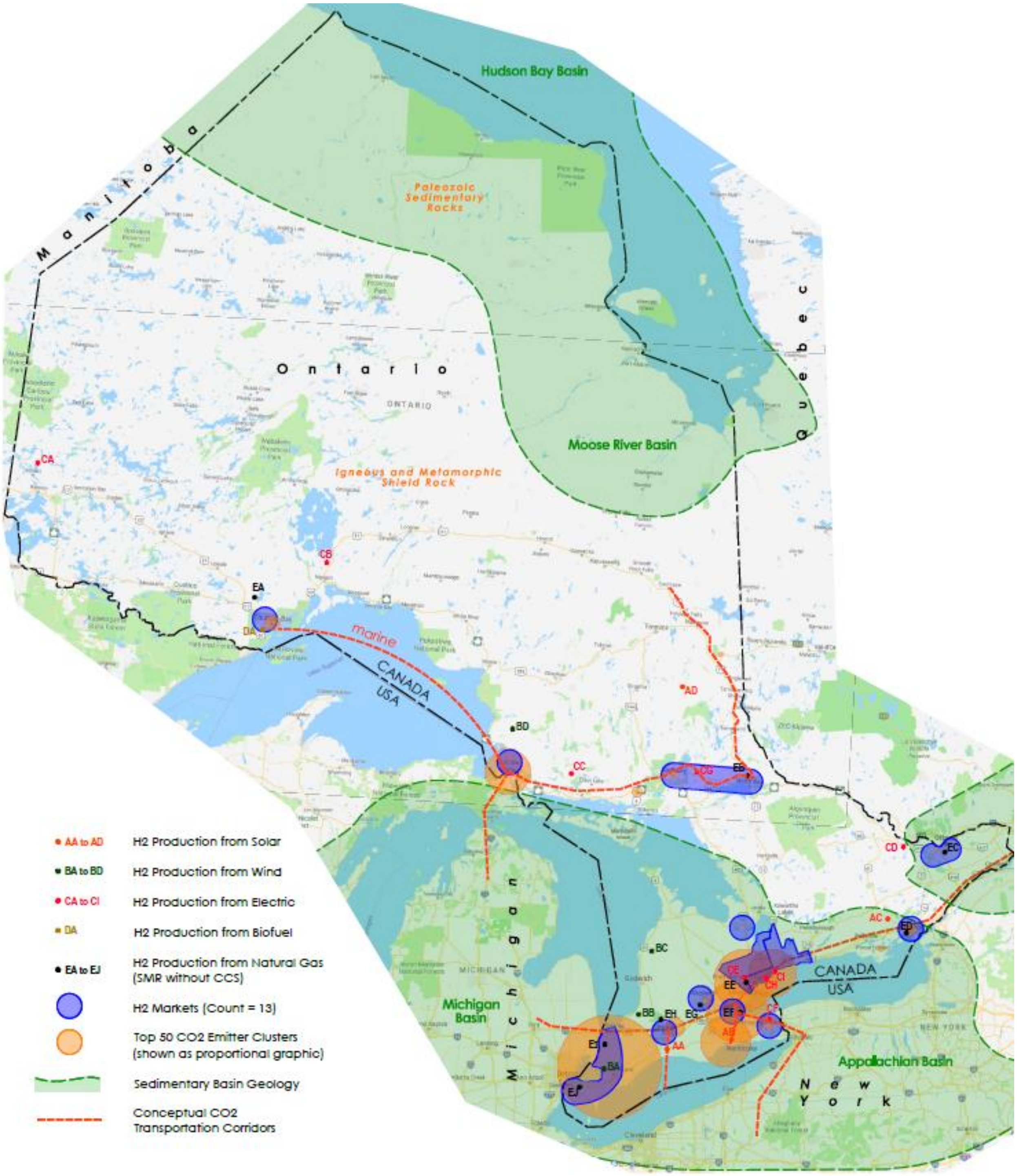
This report is intended to support and accelerate an important discussion about Ontario's potential for CCUS and the closely related opportunity for hydrogen production and storage, which intersects and integrates with systems of carbon capture and use. A summary of the technologies and systems of carbon capture applicable to Ontario's industrial facilities is presented herein. Also included is a high-level analysis of regions having carbon storage potential within the province, and the prospective infrastructural connections between sources of carbon dioxide and storage facilities that may be needed and could begin development within the next 10 to 15 years. A mapping of the locations of potential hydrogen subsurface storage sites is presented for consideration, as well as the locations throughout the province where CCUS and hydrogen production and use could concentrate in hubs of market activity.

Emerging from the review and analyses are 10 issue areas and associated recommendations for consideration by government and industry on developing Ontario's CCUS and hydrogen market and storage potential, further detailed in the concluding sections of this report.

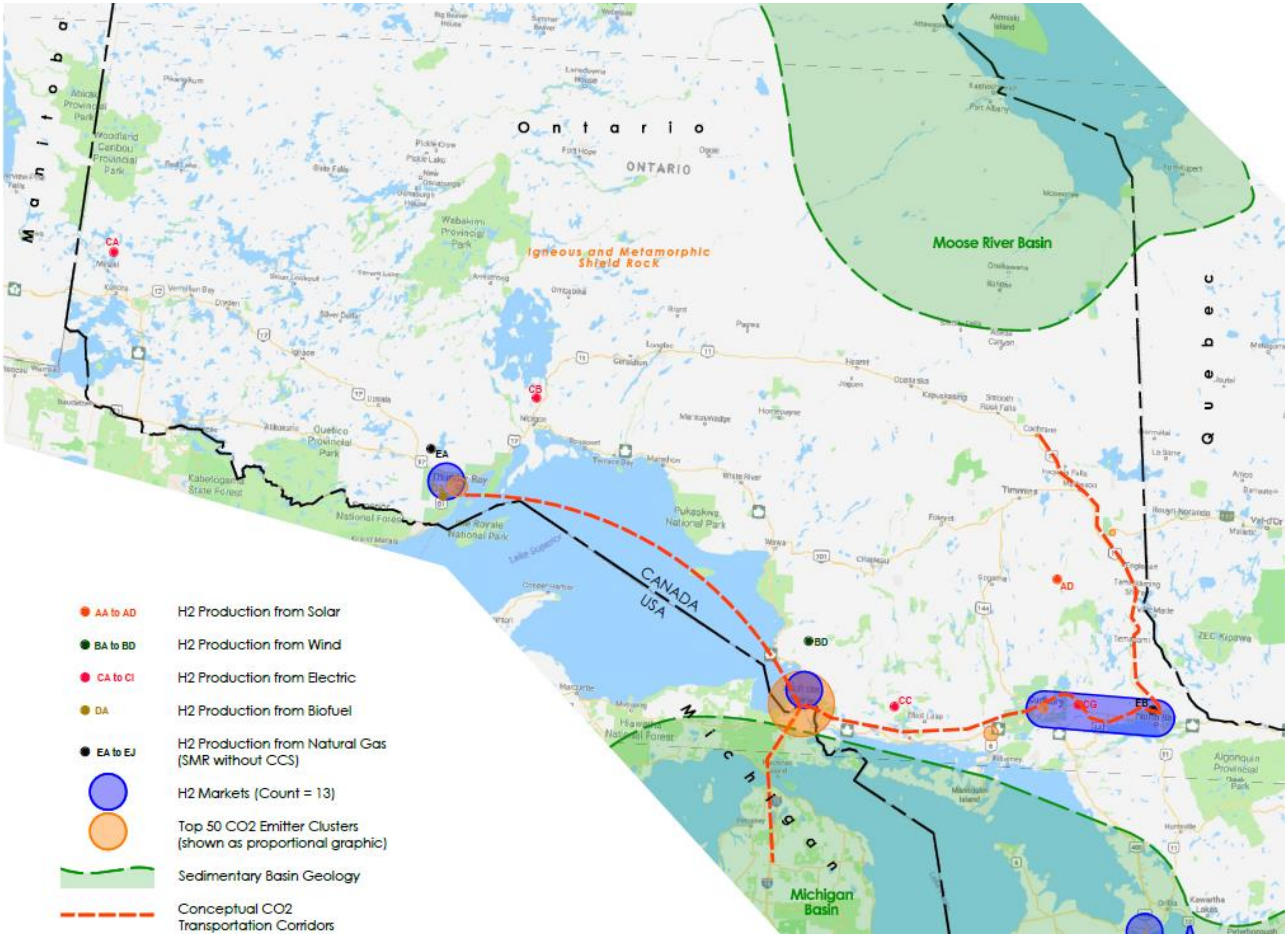
1. Government and industry should combine efforts to accelerate testing and validation of carbon dioxide sequestration potential within Ontario.
2. Government should support establishing an Indigenous Desk that ensures prospective CCUS projects incorporate the well-being priorities of Indigenous communities and lands.
3. Large industrial emitters of carbon dioxide should coordinate efforts to initiate CCUS via knowledge-sharing and public sector engagement (e.g., establish a hard-to-abate club).
4. Interjurisdictional cooperation should be pursued between governments in Canada and the U.S. to optimize geological injection and sequestration potentials, regionally.
5. Ontario industry stakeholders should make use of technoeconomic analysis services provided by CanmetENERGY under the National CCUS Assessment Framework.
6. Government should clearly articulate a comprehensive strategy for CCUS in Ontario that addresses the need for legal frameworks.
7. Government should support industry-led efforts to develop Ontario's CCUS capacities through targeted policy and programming, building upon changes to carbon storage made under the *Less Red Tape, Stronger Ontario Act, 2023*.
8. Detailed technoeconomic assessments of prospective hydrogen markets in Ontario should be commissioned by government to identify priority investment opportunities.
9. Opportunity assessments for hydrogen systems to facilitate clean energy transitions among diesel-dependent communities should be a focus of government programming.
10. Government should consider convening a stakeholder panel to assess the potential for conflicting interests in developing underground fluid storage opportunities in Ontario.

Further to the recommendations above, this report includes examples of compelling commercial opportunities associated with CCUS and hydrogen systems in all parts of Ontario. For example, the mineralization of carbon is an emerging process that could use tailing waste from diamond and metal mines in Ontario to sequester carbon from industrial emissions. In this way, industry in northern Ontario can assist the major emitters in the south to decarbonize. Such regional synergies apply to hydrogen, too, wherein its production, distribution and storage knowhow can help remote communities and industrial operations to reduce dependency on diesel for power, heat and transportation.

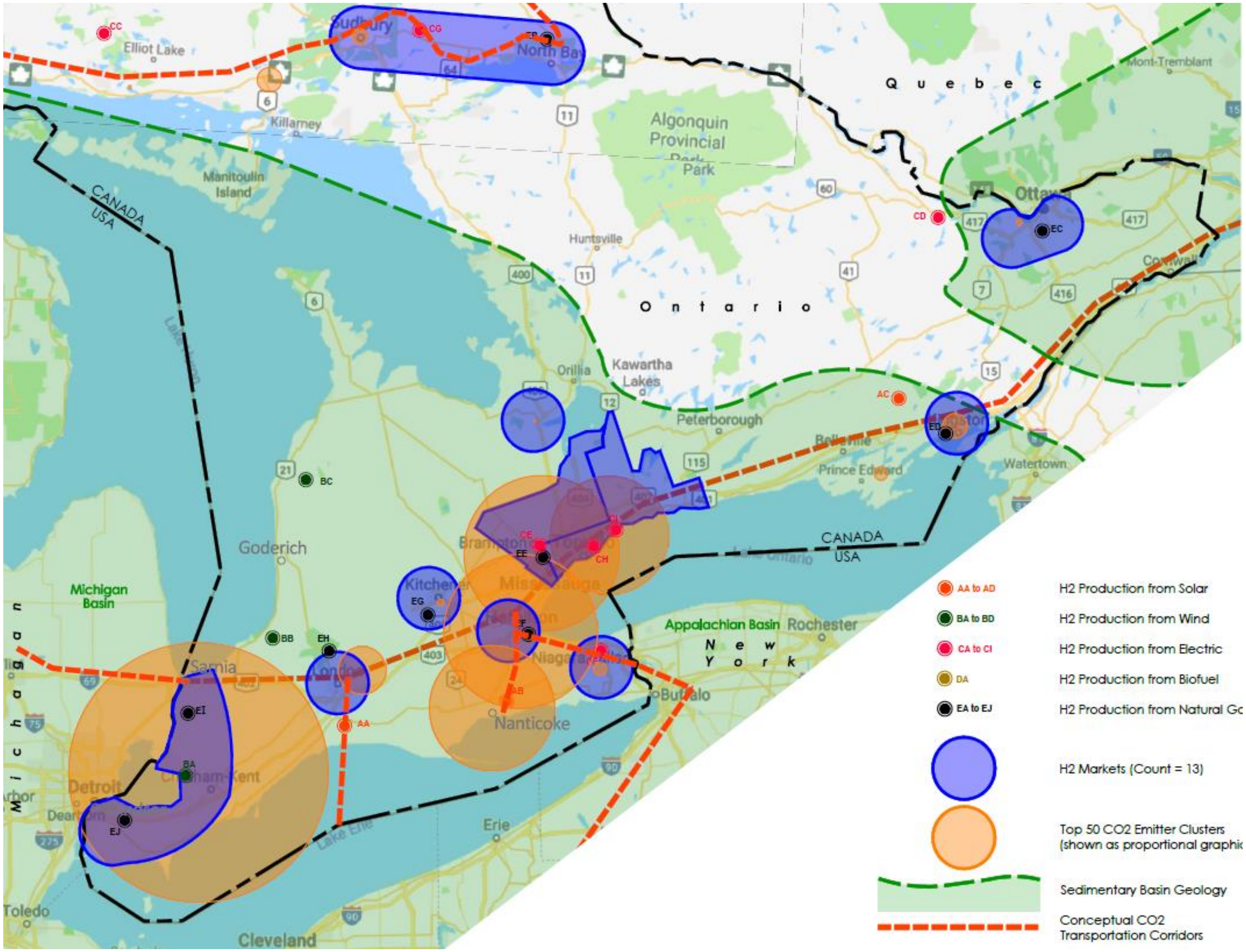
As a geospatial tool of analysis, mapping with numerous data layers has been developed by the study team. This mapping is available for all of Ontario, as well as a magnified version of Northern Ontario and Southern Ontario. Readers interested in using these map files are encouraged to reach out to Change Energy Services for assistance in developing their own analyses. Sample images of the mapping are presented below, which show the data layers representing the clustering of carbon dioxide emitters, the potential hydrogen markets and production sites, and conceptual corridors along which carbon dioxide could be transported by rail, marine shipping or pipeline from where it is captured to where it could be sequestered in geological formations, hypothetically. Consistent with the purpose of this report to provoke dialogue and ideation, carbon dioxide is depicted on this map as a commodity that can be transported interjurisdictionally. Further study and validating tests would be required to advance such concepts into plans.



Mapping Analysis – Sample Data Layers Shown



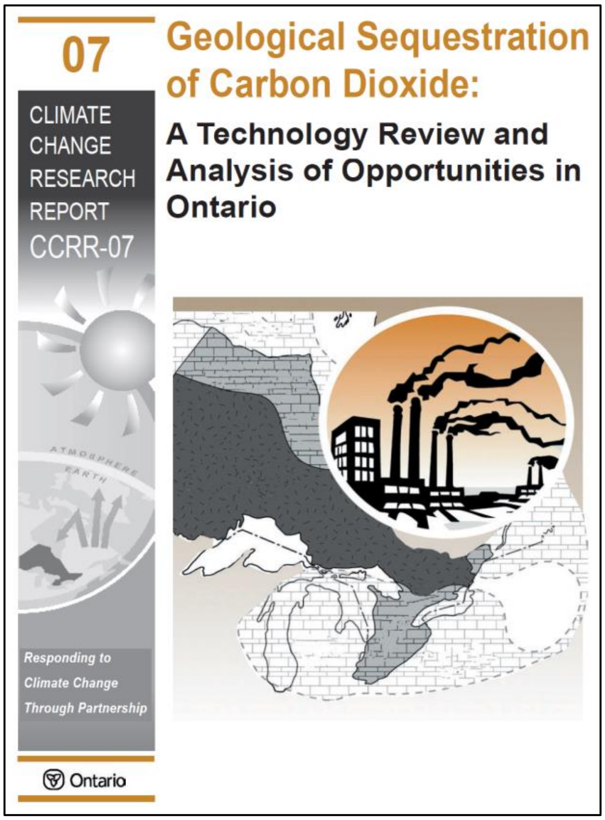
Mapping Analysis – Sample Data Layers Shown: North Region



Mapping Analysis – Sample Data Layers Shown: South Region

1.0 INTRODUCTION

In 2007, the Government of Ontario enacted the *Cessation of Coal Use Regulation*. Within seven years, coal-fired power generation had been fully phased out. Accordingly, electricity sector greenhouse gas (GHG) emissions dropped from 33 megatonnes (Mt) in 2005 to less than 4 Mt within ten years. In that same year of 2007, an Ontario government research report was produced on the subject of geological sequestration of carbon dioxide within the province [1]. The report characterized the systems of capturing carbon at large, point-sources of emissions, as well as the geologies within Ontario where the captured carbon could potentially be injected for permanent storage. To the extent that H2GO Canada has been able to determine, the 2007 report was the last published work by the government on this matter.



It appears that 2007 marks a point in time when the consideration of carbon capture and storage (CCS) ceased to be part of the broader discussion on decarbonization solutions in Ontario. At the time, CCS was often referenced in the context of reducing emissions from large, fossil fuel-fired power plants. So, it is understandable that as the province's electricity sector was progressively decarbonized, the focus on CCS would recede.

Today, the imperative to achieve deep GHG emissions reductions across all sectors of the economy brings CCS back into focus. The hard-to-abate sectors in Ontario include iron and steel, lime and cement, and chemicals and petrochemicals. The production processes involved are usually quite carbon-intensive, but not predominantly due to the combustion of fuel. Hence, the fuel-switching strategies implemented with success in other sectors, such as transitioning to renewable power in the electricity sector or the electrification of space heating and transportation, are not entirely applicable. Nonetheless, Canada's carbon pricing regime will demand solutions. Otherwise, the future of Ontario's heavy industrial base as a sustainable driver of prosperity could be at risk.

Broadly, goods-producing industry sector activity contributes roughly 22 per cent to Ontario's GDP [2] and 30 per cent to its GHG emissions inventory [3]. The ten largest emitters in the province are facilities that produce steel, cement, chemicals and petrochemicals. Carbon Capture, Utilization and Storage (CCUS) represents a potential solution space in which to mitigate these large, point-source emissions. In some circumstances, the application of CCUS strategies may involve hydrogen production or its use, as a feature of the carbon capture process. Moreover, and more directly, hydrogen can also serve as a decarbonizing agent in many of these large emitter facilities. Thus, building a strategy to enable the decarbonization of Ontario's industrial operations requires a careful scoping of the potential of CCUS and of hydrogen systems.

The purpose of this report is to make accessible the subject of CCUS and hydrogen systems to those with an interest in reducing industry sector GHG emissions in Ontario, from a geographical perspective. It presents a summary of the types of technologies and systems of carbon capture applicable to the kinds of industrial facilities based in Ontario, as well as the geologies that could serve as sites for permanent sequestration. Also included is a high-level analysis of regions having carbon storage potential within the province, and the prospective infrastructural connections between sources of carbon dioxide and subsurface storage injection points that may be needed. A mapping of the locations of potential hydrogen geological storage sites is presented for consideration, as well as the locations throughout the province where the production and use of hydrogen could concentrate in hubs of market activity.

Methodology

Mapping the geography of CCUS potential in Ontario, the locations where commercial hydrogen markets are likely to develop, and the geological opportunities for underground hydrogen storage, helps to visualize the results of the research and analysis, and encourages readers to draw their own connections and identify opportunities based on their unique understanding of their industry and the province.

To generate these maps, H2GO Canada built a core study team composed of technical researchers. This study team conducted a scan of publicly available literature on the subject of carbon dioxide (CO_2) capture and storage. This subject broke out into two areas of parallel study; (1) the technologies and systems of CO_2 capture, and (2) the characteristics of geologies into which CO_2 can be injected and permanently sequestered. Through this research, a third area of study was added, involving technologies and systems where carbon is captured for practical uses or for storage, but *not* for injection into underground geological formations. The findings were synthesized into a narrative report (see section 3.0), filtering for content that was directly applicable to an Ontario context, in terms of industrial profile and geology.

A mapping exercise followed, in which the largest emitters of CO_2 were identified by location. Large emitters in Ontario often cluster in industrial areas, so regions of high CO_2-emitting activity were also mapped. Maps of the promising geological formations for CO_2 injection and storage were then developed, based on the literature review. This facilitated a virtual prospecting exercise, in which transportation modal connections were envisioned for moving CO_2 from the sites where it is captured to the sites where it can be stored, potentially.

The process was repeated for hydrogen systems and storage. Drawing on analysis presented in a companion report by H2GO Canada, *Estimating Low-Carbon Hydrogen Supply and Demand in Ontario to 2050, Based on an Assessment of Effective Value Chain Development*, a set of 18 markets wherein hydrogen production and use is expected to grow in different regions of the province. This mapping relied heavily on the judgement of the study team, made up of professionals having prior experience and expertise in the development of markets for fuels, including hydrogen. It also required an examination of the major energy assets and transportation infrastructure crisscrossing Ontario, and its regional population densities. The characteristics of these markets were influenced by the major, local feedstocks to hydrogen production and the primary, local applications creating anchors of demand.

Accompanying the maps of Ontario's prospective hydrogen markets are potential sites for subsurface hydrogen storage in available geological formations. These assessments are based on a review of literature similar to the study of CO_2 capture and permanent sequestration, but focused on temporary storage of hydrogen to accommodate asymmetries in the profiles of supply and demand over time (similar to how stores of natural gas are accumulated in underground reservoirs in the warm season, later to be drawn down during the cold weather when demand for space heating peaks).

Consultations with experts and industry stakeholders

Throughout the project, the study team reached out to professionals with expertise in different aspects of CCUS, including geology, technoeconomic evaluation and law, and to representatives of key industry sectors whose operations in Ontario are confronted with choices regarding future decarbonization pathways, including those enabled by CCUS and hydrogen. Some are assessing imminent investments in technologies and processes needed to achieve GHG emissions reductions targets to 2050; others are looking to lever CCUS and hydrogen systems as new commercial growth opportunities in the near term. The input and opinions of the experts and stakeholders engaged contributed to the study team's appreciation of the subject matter, informed the research and enriched the mapping analyses.

What happens next?

This report is one in a series that H2GO Canada will be developing for public release in the coming months, known as the Ontario Hydrogen Foundation Studies. Consistent with this title, the aim of the studies is to fill identified gaps in knowledge, understanding and analytical capacity among those individuals and institutions seeking to use the potential of hydrogen systems to achieve positive, tangible outcomes within their communities. The audiences for the Ontario Hydrogen Foundation Studies include Indigenous Communities, government, industry, academia and civil society organizations. Through the series of reports, H2GO Canada hopes to build interest and inspire confidence in developing and advancing hydrogen initiatives among these societal groups.

To that end, observations and recommendations of the study team are presented in the concluding sections of this report. Potential roles and opportunities for cross-sector collaboration (and cross-jurisdictional engagement) are identified. As well, throughout the body of the report, brief vignettes are added to illustrate novel applications of CCUS and hydrogen systems toward new commerce, energy prosperity and sustainable development.

2.0 CAPTURING, STORING AND USING CARBON DIOXIDE – A REVIEW OF THE APPROACHES AND TOOLS APPLICABLE TO ONTARIO

2.1 Capturing Carbon Dioxide

Preventing as much CO_2 as possible from entering the atmosphere starts with capturing it before it is released. Under typical atmospheric conditions, CO_2 is in a gaseous state and is thus light and diffuse. As it disperses into the air, the concentration of CO_2 lessens, making containment more difficult. Therefore, capturing CO_2 close to its source, where it is more concentrated, has been a design focus of many systems of carbon-capture. There are many industrial processes that are sources of CO_2 emissions. The source could be a combustion reaction between oxygen and a hydrocarbon fuel, or it could be the point of some other chemical reaction in which CO_2 is a major product, such as occurs in the smelting or direct reduction of iron ore into iron for steelmaking, or in the formation of lime in a cement kiln to produce clinker. Prospectively, the capture of CO_2 for the purpose of reducing GHG emissions will rely on processes and technologies already used in various industries – especially in the chemicals and petrochemicals sectors. The challenge is in scaling up established processes to match the needs of large, industrial emitters within the next decade. As well, emerging solutions require continuing development to achieve commercial adoption in the longer-term. Four categories of CO_2 capture – each enabled by a range of specific, commercially-established technologies – are considered in this report: post-combustion, pre-combustion, recycle/oxyfuel combustion and industrial process stream. A fifth category is also included, representing more recently developed approaches to CO_2 capture; namely, direct air capture and mineralization.

2.1.1 Post-Combustion CO_2 Capture

The main products of combustion of a hydrocarbon fuel with oxygen in air are water (H_2O) and CO_2.

$$Fuel\ (H_aC_b) + Air\ (O_2 + N_2) \rightarrow H_2O + CO_2 + NO_x$$

In the context of a large, industrial facility, such as a natural gas- or biomass-fired power plant, post-combustion capture involves separating CO_2 from the stream of flue gases – that is, the products of combustion that are exhausted to atmosphere. These emissions may also include oxides of nitrogen, NO_X (as air is nearly 80 per cent nitrogen), oxides of sulphur (from sulphur natively present fossil fuel feedstocks), carbon monoxide and various hydrocarbon compounds (products of imperfect or partial combustion), particulate matter and trace levels of metals. These elements and compounds in the flue gas must be separated to produce a stream of CO_2 that is suitably pure for subsequent, commercial use or for permanent storage.

The most commercially established means of post-combustion capture of CO_2 from flue gases relies on the use of chemical solvents (or sorbents) that effectively absorb CO_2 through direct contact. When the optimal CO_2 uptake is reached, the solvent is moved to a different unit where the CO_2 can be released and sent for further processing. Release of the CO_2 from the solvent requires an input of energy in the form of a change in temperature or pressure (or some other condition). This regenerates the solvent, making it ready for further absorption of CO_2. As this cycle continues, the efficacy of the solvent degrades, requiring make-up additions of fresh solvent. Naturally, solvents with greater loading capacity, lesser rates of degradation and regeneration energy are most attractive, which serves as a driver of innovation in the field.

Ideal solvent performance requires careful management of the flue gases, and this requires several components of technology operating in balance. Some of these components are represented in the process flow diagram shown in Figure 1. Depicted is the flue gas fed into the process, which must be cooled before entering the absorber vessel – optimally solvent performance usually ranges between 40 and 60 degrees-Celsius. Blower fans maintain pressure as the flue gases pass through the absorber. Prior to exhaust, the flue gases (now depleted of CO_2) pass through a spray of water, adding moisture needed later in the process and rinsing any solvent vapours from the flow. The exhaust is now 80 to 95 per cent free of the CO_2 content originally in the flue gas, which is emitted to atmosphere. The exact level of CO_2 capture is mainly a function of cost. All else held equal, a taller vessel will reduce CO_2 concentrations further, but cost more. Not shown in the diagram are any pre-treatment systems upstream of the feed gas, which may be required depending on the nature of the fuel and its combustion. As mentioned above, this includes the removal of oxides of nitrogen and sulfur, the presence of which would compromise the CO_2 absorption performance of the solvent, as well as particulate matter. To achieve this, selective catalytic reactors to reduce nitrogen oxides, desulphurization units and electrostatic precipitators to reduce soot and ash in the emissions stream are commonly used. Note that such pre-treatment technologies are mature since they are often required to comply with established air quality regulations in many jurisdictions.

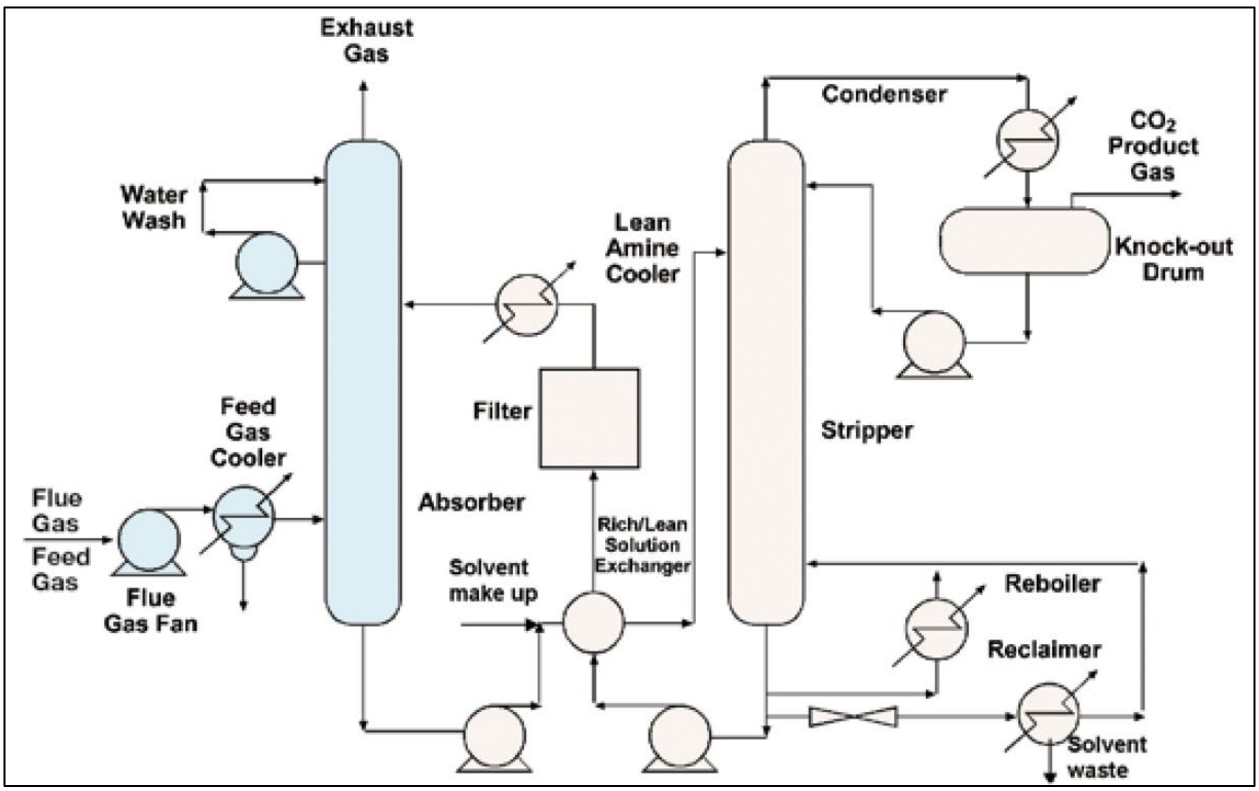


Figure 1: Process flow diagram for CO_2 recovery from flue gas by chemical absorption
Source: IPCC Special Report on Carbon Dioxide Capture and Storage [4]

The regeneration process involves a separate cycle that is balanced to the throughput of the flue gases. Solvent in the absorber, now loaded with CO_2, is pumped to the stripper vessel where it is heated using steam (indirectly). At around 100 to 140 degrees Celsius, the CO_2

desorbs from the solvent, while the flow of produced steam (arising from the indirect heating of the solvent) serves as a stripping gas, carrying the released CO_2 to a condenser where the flow is cooled. Water condenses out of the stream leaving CO_2 at a high level of purity, ready for collection and transport away from the facility. The solvent circulates back to the absorber vessel and the cycle continues. Some treatment of the solvent is needed to remove the degraded portions and any impurities acquired in the cycle. Make-up solvent is added to restore the proper volume for the absorber process.

The process described above is currently used in many facilities worldwide, where the captured CO_2 has market value. Often, this CO_2 is used in enhanced oil recovery operations, in which the pumping of CO_2 into depleting oil fields provides the pressure required to continue extraction and thus extend the productive life of the resource. There may be other valuable uses for the CO_2, as well, but there are practical limits to the offtake potential. This is because the CO_2 capture system requires energy and space to operate. Flue gases are emitted at atmospheric pressure, so the treatment of the flow requires substantial volume. For very large emitters, such as power plants or primary processing facilities – say, for iron, lime or cement production or for chemicals and petrochemicals refining – the equipment will occupy a substantial footprint. The inset photo of the Petra Nova coal-fired generating station in Texas shows the relative size of the operating post-combustion CO_2 capture systems compared to the rest of the station. Here, about one-third of the flue gases from a 650 MW generating unit are fed into the system for separation of carbon. This is one of two power plants currently operating with carbon capture and storage; the other is the 100-MW Boundary Dam plant in Saskatchewan.

Figure 2: Petra Nova coal-fired power plant with CCS system, near Houston, Texas
Source: U.S. Energy Information Administration [5]

The taller column in the foreground houses the absorber vessel. The smaller column to its left is the stripper. The low structure in front of the columns houses the compressors that pump the CO_2 to an enhanced oil recovery operation more than 100 km away. A dedicated cogeneration plant, appearing in the left of landscape, provides the electricity and heat that powers the overall CO_2 capture process, principally the regeneration cycle for the solvent.

In a 2005 report prepared for the Intergovernmental Panel on Climate Change (IPCC) [4], the incremental cost of current systems of CO_2 capture is estimated to add 35-70 per cent to the cost of electricity produced at a natural gas combined cycle power plant. This range applies to post-combustion CO_2 capture, as well as to pre-combustion and recycle/oxyfuel systems (described in the subsections that follow). The cost per tonne of CO_2 captured ranges from US$11 to US$57 in these estimates. However, the report estimates that the cost of capturing CO_2 that is a by-product of certain chemical processes (i.e., not combustion for power generation) are at the low end of this range. An example is hydrogen production from methane, which produces a concentrated stream of CO_2. Such processes may be the readiest, least-cost hosts for initial deployments of CO_2 capture systems, provided there is a proximate, offtake receiver of the CO_2; that is, a use or storage and sequestration opportunity. If, in some circumstances, a supply of waste heat may be available to drive the regeneration process, then this could dramatically improve system efficiency.

Other post-combustion systems exist or are under development, involving an array of distinct processes and technologies. Examples include solid sorbents based on lithium- or calcium carbonate-based compounds instead of aqueous solvents, such as amine-based chemicals; adsorption instead of absorption, in which desorption of the captured CO_2 is achieved with changes (or swings) in pressure or temperature (i.e., pressure swing adsorbers) of the adsorbent material (e.g., activated carbon, zeolites); and the novel application of membrane technologies, normally only effective in higher pressure gaseous systems, to solvent-based CO_2 capture in a hybrid solution. Mineralization of CO_2 into carbonate forms, which mimics the natural process of rock-weathering, is also being researched, and is addressed later in this section. Incremental improvements in solvent performance and mechanical system designs can reduce the efficiency penalty of CO_2 capture and improve cost-effectiveness.

CanmetENERGY at Natural Resources Canada is developing a suite of tools to promote CCUS system optimization using machine learning and a robust database of design factors that represent both established and emerging technologies.

2.1.2 Pre-Combustion CO_2 Capture
Ontario Opportunity: Production of low-carbon hydrogen and carbon black

Capturing CO_2 prior to combustion involves a series of reactions between the hydrocarbon fuel and the oxygen in air to produce a synthesis gas, mainly composed of carbon monoxide (CO) and hydrogen (H_2). Commonly called syngas, this mixture is heated with steam to cause a Water Gas Shift reaction, in which oxygen dissociates from the water (H_2O) and bonds with the CO in the syngas to create CO_2. Thus, the application of steam converts the syngas (CO + H_2) into a mix of CO_2 and H_2 gases, which can be separated using some of the technologies described in the previous section; principally solvents or pressure swing adsorbers (PSAs). At this point in the process, the CO_2 is diverted while the H_2 can be advanced to use in combustion or for other purposes. Since H_2 is absent of carbon, its use as a fuel does not produce any CO_2.

Hydrocarbon Reforming	$C_xH_y + xH_2O \leftrightarrow xCO + \left(x + \frac{y}{2}\right) H_2$
Steam Reforming	$CH_4 + H_2O \leftrightarrow CO + 3H_2$
Water Gas Shift Reaction	$CO + H_2O \leftrightarrow CO_2 + H_2$
Overall Reaction	$CH_4 + 2H_2O \leftrightarrow 2CO_2 + 4H_2$

There are many systems currently used in pre-combustion separation and capture of CO_2, the application of which varies according to the hydrocarbon fuel and the industrial circumstance. Steam methane reformers (SMRs) are commonly used to produce hydrogen from natural gas (and other, similarly light fuels). Sulphur present in the fuel must first be removed since reforming the methane into syngas relies on a catalyst that will cease to operate in the presence of sulphur. A portion of the fuel is burned to create the temperature conditions needed for the catalytic reaction to occur (800-900^{o}C). The resulting syngas is cooled, transferring its heat to a boiler that helps generate the steam required by the CO shift reactors. The output gas from the shift reactors is mostly CO_2 with residual amounts of CO left over (the less CO, the more CO_2). The CO_2 and H_2 gas mixture is then cooled so that the separation process can occur. Decades ago, solvents were used to absorb the CO_2; more recently, PSAs using a solid adsorbent, such as activated carbon, alumina or zeolites, have become the more common method of collecting the CO_2 and separating it from the H_2 gas. PSAs are capable to producing high-purity hydrogen, sufficient for most industrial purposes (though fuel cell-grade purities usually require further purification). The stream of CO_2 released during the regeneration cycle is not pure, containing some methane and H_2. This allows it to be burned as a supplemental fuel to heat the catalytic reformer earlier in the process. This final combustion converts the remaining methane and H_2 into CO_2 and water, which are exhausted to atmosphere if not captured. To capture the CO_2 at this point, the post-combustion technologies described in the previous subsection can be applied. Design studies estimate that a large, modern SMR plant without capture will generate roughly 9 kilograms of CO_2 for each kilogram of H_2 produced. The application of established, solvent-based absorbers systems could capture perhaps 8 kg of CO_2 per kg-H_2 produced, with 1.4 kg-CO_2 emitted to atmosphere (the extra fraction of CO_2 owes to additional combustion stages, such as the solvent regeneration), based on estimates in the IPCC report.

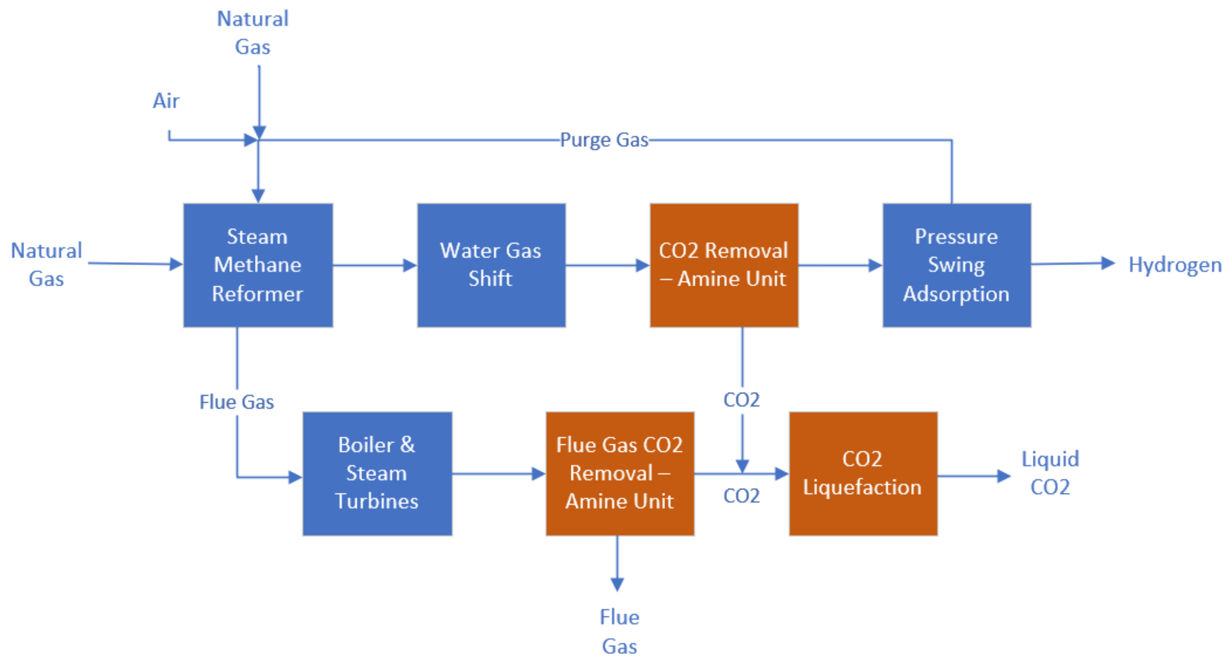


Figure 3: SMR Process with Carbon Capture

One issue with SMR plants is the presence of nitrogen from the air that supplies the oxygen, as this decreases the efficiency of CO_2 separation later in the process. Partial oxidation (POX) processes are a common alternative, in which pure O_2 is used in the reformer instead of air, and the reforming reaction occurs at high pressure. This type of reaction generates heat sufficient for the CO shift reactors, so no further fuel is needed. The supply of pure oxygen adds cost, but this is offset by more efficient CO_2 separation. Also, POX plants can accommodate a wider range of fuels than traditional SMRs.

Autothermal reforming (ATR) is a process that combines aspects of SMR and POX systems. A partial oxidation process generates the heat and steam for the CO shift reaction, but this does not occur in a separate reactor. Instead, a single chamber houses a combustion zone, where the syngas is formed, as well as some water and CO_2, a thermal zone where further syngas is produced, and a catalytic zone, where water gas shift reactions take place. The catalyst must be chosen to support both the reforming and shift reactions. The gases exiting the chamber still include some CO, so a downstream shift reactor may be needed to complete the formation of CO_2 and H_2. The advantages of ATR over SMR include compact design, lower cost, lower operating temperatures and simpler control of temperature, and fewer CO_2 emissions (since the partial oxidation process supplies all the heat needed by the ATR unit). However, use of pure oxygen adds cost back to the system, the economics of which are often manageable if the ATR plant is sized for a larger throughout capacity.

Figure 4: An ATR unit operating in an Air Liquide facility to produce hydrogen gas
Source: Air Liquide Engineering & Construction [54]

Gasification is a common process applied to heavier and solid hydrocarbon fuels, such as coal, petroleum residues and biomasses, to produce a stream of syngas from which higher-value products can be synthesized. The hydrocarbon feedstock is partially oxidized, often in the presence of steam, to produce CO and H_2, along with water and CO_2. Shift reactions follow to produce rich streams of CO_2 and hydrogen, which can be separated (see reactions table above). Based on the hydrocarbon and the oxidant (i.e., pure oxygen or air), there could be various impurities that also need to be managed. Gasification plants are typically large and thus produce large volumes of fairly pure CO_2. They often function to produce syngas for use in combined cycle gas/steam turbine power plants, in chemical plants (e.g., ammonia production), and in the production of synthetic fuels from coal, including synthetic natural gas or liquid fuels (based on a Fischer–Tropsch process). CO_2 is usually vented to atmosphere but in some cases, it is diverted to valued end-uses. For example, a coal gasification plant in North Dakota sends some its CO_2 to Weyburn, Saskatchewan, where it is sequestered underground as part of enhanced oil recovery operations [6].

Capture of CO_2 in gasification systems usually relies on the established solvents or sorbents previously described in the post-combustion capture subsection. The optimal solution is a matter of chemical engineering, and the combination of technologies will vary from site to site.

An important, emerging pre-combustion capture technology is methane pyrolysis, which is the thermal cracking of CH_4 (methane) to yield C (pure carbon) and H_2. Pyrolysis involves the application of heat in the absence of oxygen, so there is no oxidation. Thus, heat must be externally applied to the reactor for thermal cracking to occur. Sometimes a catalyst is used but not always. Heat can also be supplied via a plasma arc generated by electricity. Most recently, microwave pyrolysis has been promoted as a solution and is under development by numerous firms. U.S.-based HQuest, for example, is currently marketing a microwave pyrolysis system to industrial facilities as a solution to decarbonization process heat. Essentially, the HQuest reactor intercepts a plant's natural gas supply, using its microwave-controlled plasma jet to precipitate elemental carbon out of the fuel. The resulting hydrogen is then used as a carbon-free combustion fuel in place of the natural gas. The elemental carbon may also have market value. According to HQuest, the plasma jet can be modulated and shaped to produce different grades of carbon to meet varying market demands for carbon black product.

Figure 5: Samples of carbon black produced by the HQuest system
Source: Photo by Bob Oliver, 2022

Ontario Opportunity: **Producing low-carbon hydrogen and carbon black**

Canada's Aurora Hydrogen, with offices in Toronto, Edmonton and Vancouver, is developing a technology that uses efficient form of microwave pyrolysis of natural gas to produce hydrogen and solid carbon, which obviates emissions of CO_2. The technology is highly scalable and modular, units can be installed anywhere there are ready supplies of natural gas and electricity. Hydrogen production using Aurora's technology has the potential to reduce global CO_2 emissions by over 500 Mt, annually. The system is expected to enter commercial use in the 2025-2030 timeframe.

Aurora Hydrogen's Chief Science Officer is Dr. Murray Thomson, Professor of Mechanical Engineering at the University of Toronto. Successful commercialization of Aurora's proprietary technology could help to make Ontario's extensive natural gas distribution system as principal source of clean hydrogen feedstock and carbon black for use in the production of emerging carbon-based, high-strength materials.

Fuel cell technologies can also be used as a type of pre-combustion CO_2 capture system. Fuel cells generate heat and power through electrochemical reactions; that is, no combustion takes place. As a result, fuel cells are not limited by the practical efficiency limits of combustion engines, and often operate at twice the energy conversion efficiency of piston-crank engines and turbines. Fuel cells are commonly associated with pure hydrogen fuel, but there are also types designed to use hydrocarbon fuels that are rich in hydrogen, such as methanol, ethanol and syngas. The oxidation of such fuels in a fuel cell produces highly pure streams of nitrogen gas and carbon dioxide, which can be separately captured. In this situation, high-temperature fuel cells (e.g., solid oxide technology) would be attractive, as the heat generated could be used in the pre-treatment of the fuel and in any CO_2 capture systems downstream, improving overall system efficiency.

2.1.3 Recycle / Oxyfuel Combustion CO_2 Capture

Recycle/oxyfuel systems represent a special type of post-combustion CO_2 capture. Instead of air, which is mostly nitrogen gas, pure oxygen is burned.

$$Fuel\ (H_xC_y) + O_2 \rightarrow H_2O + CO_2$$

This all but eliminates nitrogen gas in the exhaust stream, leaving mainly CO_2 and H_2O, which are easily separable by condensing the water. The concentrated stream of CO_2 is then dried and purified, as needed, for compression and transport. Capture efficiency can be very high in such systems.

The combustion temperature when pure oxygen is used instead of air is too high for practical, industrial use, such as in boilers or turbines. So, the flue gases are recycled back into the combustion process to dilute the oxidant and reduce the temperature. This is often supplemented with an injection of water into the combustion chamber to provide finer control of the temperature.

Figure 6: A cold box at a Linde industrial gas facility
Source: Linde [55]

Commercial-scale recycle/oxyfuel combustion CO_2 capture systems are not currently in use, but the handling of the CO_2 is expected to rely on established methods. For example, the production of pure oxygen for use as oxyfuel is well-established. Air separation units (ASUs) are common technologies for producing oxygen and nitrogen, as well as other inert gases in air, such as argon. The most common ASU types include cryogenic distillation, in which air is cooled via refrigeration until it liquefies, after which the constituent gases are fractionally separated by boiling point as they warm. Due to their high demand for input energy, cryogenic ASUs are often economic only for large volume production of gases, while PSA ASUs are usually suitable for smaller applications. Figure 6 shows an insulated enclosure, called a Cold Box, that contains the fractional distillation column and associated equipment comprising an cryogenic ASU.

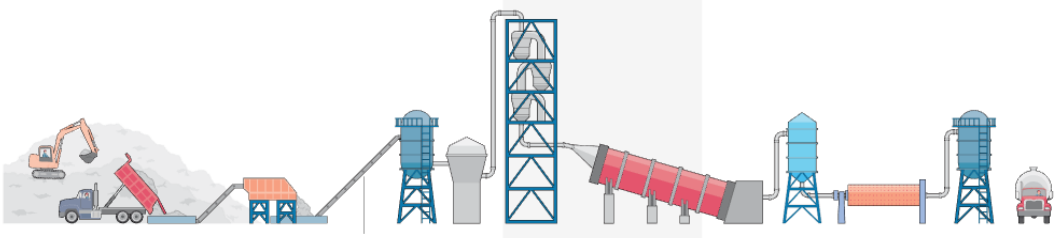
2.1.4 Industrial Process Stream Capture of CO_2

The capture of CO_2 at certain points within an industrial process is common and uses established technologies. Often, the purpose of extracting CO_2 from a process stream is to vent it to atmosphere as waste by-product. This occurs in the purification of natural gas, combined SMR and ammonia plants, commercial alcohols and synthetic fuels and lubricants, to name a few. In some cases, however, the extracted CO_2 is used as feedstock for other production processes. For example, the production of urea fertilizer involves reacting captured CO_2 with ammonia to make carbamate. The means of CO_2 capture in these examples align with the post-combustion systems described earlier.

Very often CO_2 is not actively managed and separated for venting but is merely released into the atmosphere with no specific treatment to the CO_2. For example, in cement-making, most of the CO_2 is produced in fuel combustion to heat the kiln and also in the calcination process to produce lime (calcium oxide, CaO) from limestone (calcium carbonate, $CaCO_3$).

Cement manufacturing is a highly complex process.

Raw materials, energy, and resources | **Clinker and cement manufacturing**



	Quarry	Crusher	Transport[1]	Raw mill	Kiln and preheater/ precalcinator[2]		Cooler[3]	Cement mill	Logis-tics[4]	**Total**
Energy, mega-joule/ton	40	5	40	100	3,150		160	285	115	3,895
CO_2, kilogram/ton	3	1	7	17	479 Calcination process	319 Fossil fuels	28	49	22	925

[1]Assumed with 1kWh/t/100m.
[2]Assumed global average, data from the Global Cement and Concrete Association, Getting the Numbers Right 2017.
[3]Assumed reciprocating grate cooler with 5kWh/t clinker.
[4]Assumed lorry transportation for average 200km.

Figure 7: CO_2 emissions generated at different points in the cement-making process
Source: Hanley [56]

In steelmaking, CO_2 is predominantly a product of iron ore processing, the coking of coal and of fuel combustion in furnaces. Post-combustion capture of CO_2 techniques are applicable in these examples, but use of pre-combustion and recycle/oxyfuel methods may also be an option. For example, CO_2 emissions from cement kilns are more concentrated than from other, large industrial combustion sources, so post-combustion capture systems could be an efficient solution. Whereas in steel plants, recycle/oxyfuel CO_2 capture solutions could be applied to reduce (though not eliminate) CO_2 release, in operations that use blast furnace gases as combustion fuel. Also, the use of hydrogen as the reducing agent in direct reduction of iron (DRI) could nearly eliminate CO_2 emissions in ironmaking, provided any CO_2 produced in the hydrogen making process was captured and stored.

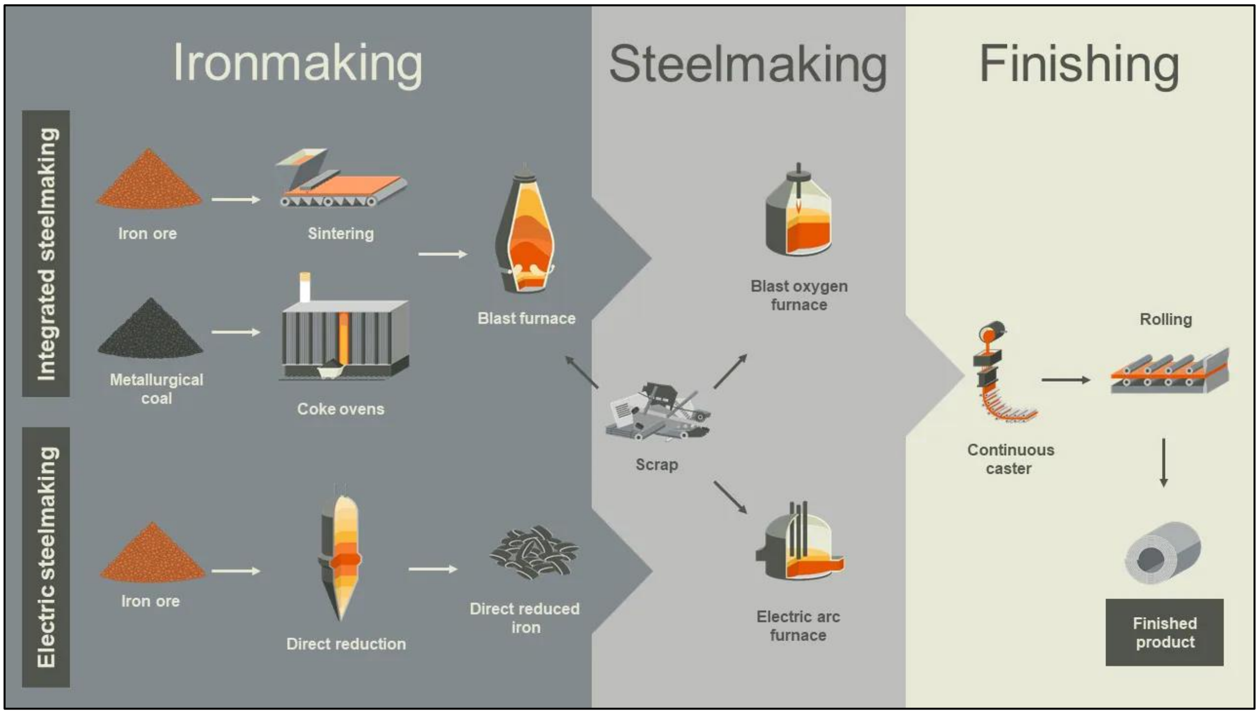


Figure 8: Common steelmaking production processes
Source: Ellis and Bao [57]

The estimated costs for CO_2 capture in industrial process streams are often reported as lower than for CO_2 capture in fuel-burning power plant scenarios. This reflects circumstances in which the CO_2 stream is more concentrated compared to the CO_2 in combustion flue gases, and thus can be more efficiently captured. The IPCC special report on CCS thus predicted that carbon capture for use or storage may become economical soonest in some industrial applications, to be followed by natural gas-fired power plants.

The process flow diagram below summarizes the sequence distinctions between post-combustion, pre-combustion, recycle/oxyfuel and industrial process capture of CO_2.

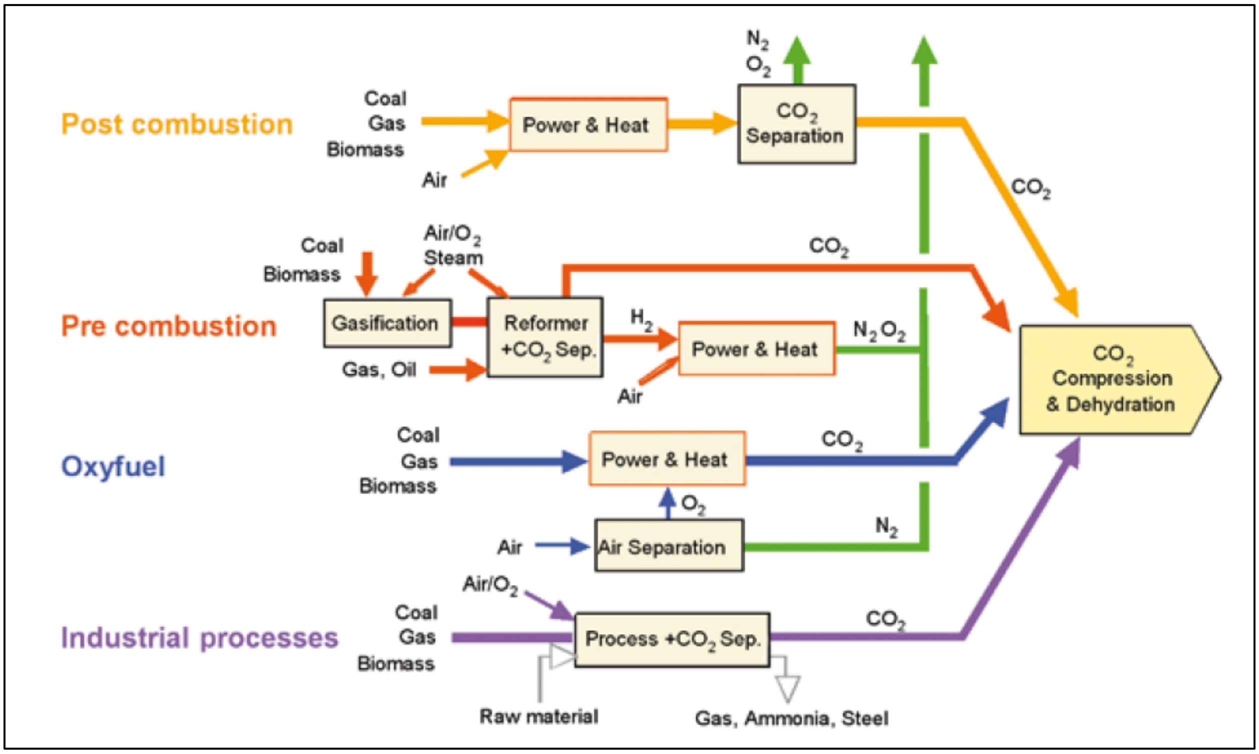


Figure 9: CO_2 capture processes, flow diagram
Source: IPCC Special Report on Carbon Dioxide Capture and Storage [4], adapted from BP materials

2.1.5 Direct Air Capture of CO_2 (DAC)

The capture of CO_2 directly from air has been occurring for as long as cryogenic air separation units (ASUs) have been operating. Air drawn into an ASU is mainly composed of oxygen and nitrogen (roughly one-fifth and four-fifths, respectively) but there are minute amounts of CO_2 (at concentrations of roughly 0.04 per cent, or 400 ppm … *and rising*) and other gases having commercial value, as noted in the foregoing text. However, air is a very diluted source of CO_2, which is why its direct extraction from the atmosphere has been historically considered an economically impractical effort. Yet, CO_2 is drawn out of the air by plants and bacteria via photosynthesis every day; indeed, it is the very basis of life on earth.

Carbon Engineering is one Canadian company that is attempting to commercialize industrial-scale Direct Air-Capture (DAC) of CO_2. The primary motivation is to mitigate climate change, but to pay for the service, CO_2 offtake opportunities with current market value are being cultivated. One application is in enhanced oil recovery. Another is in the development of synthetic fuels, where the carbon drawn from the atmosphere and hydrogen produced from low-carbon sources can be combined to yield liquid fuels that are nearly net-zero in carbon-intensity (e.g., sustainable fuels that are functionally equivalent to gasoline, diesel or aviation fuel).

The DAC process developed by Carbon Engineering relies on large volume air handling to achieve meaningful levels of CO_2 capture. The process is novel but the technological components of the system are all based on commercially established equipment. As such, accurate estimation of system costs should be possible. In 2018, the company published a detail economic assessment of their DAC solution for public scrutiny. The image below is taken from this paper to illustrate the process flow.

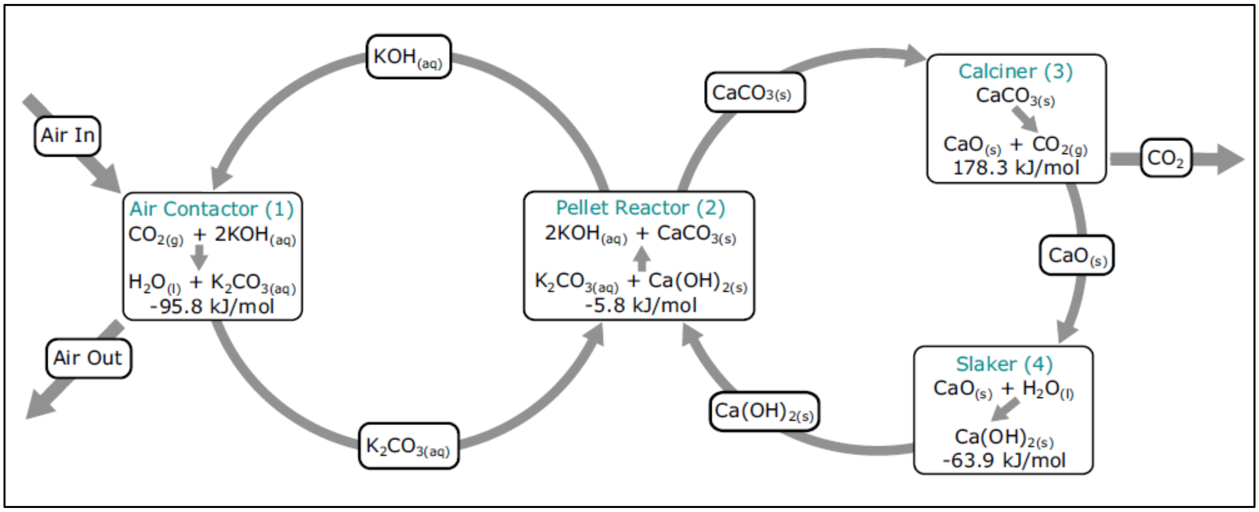


Figure 10: Carbon Engineering DAC process chemistry and thermodynamics
Source: Keith *et al.* [7]

Beginning with the air contactors, large fans draw in ambient air across a fluid, similar to how typical cooling towers operate. The fluid is an aqueous solution composed of a sorbent, potassium hydroxide (KOH), and water. The geometry of the surfaces over which the sorbent flows is designed to maximize crossflow contact with the intake air and an optimized chemical gas-exchange, where the CO_2 reacts KOH to produce a K_2CO_3 and H_2O solution. The solution is pumped to a oxyfuel-fired, fluidized bed pellet reactor, in which calcium hydroxide, $Ca(OH)_2$, is added to react with the sorbent solution to form calcium carbonate, $CaCO_3$ pellets, while potassium and OH ions bond to form KOH. The pellets accrete, becoming heavy and eventually drop to the bottom of the reactor in a fluid mixture with the reformed KOH. The solution passes into a centrifuge to separate the pellets from the KOH, which is circulated back to air contactors with water to collect more CO_2. The dried pellets with captured carbon are moved to a circulating fluidized bed calciner unit, where heat (from natural gas and oxyfuel combustion) is applied to separate the $CaCO_3$ into CaO and CO_2. The CO_2 is ready for further purification and transport to storage or end-use applications. The CaO is sent to a slaker where it is mixed with water to form $Ca(OH)_2$ for use in the pellet reactor.

Carbon Engineering's demonstration plant in British Columbia, operating since 2015, has capacity to 1 tonne of CO_2 capture per day, but a 1-megatonne CO_2 plant is in development with an Occidental Petroleum subsidiary for use in enhanced oil recovery operations in Texas. In this application the direct air-captured CO_2 will be permanently sequestered in the Permian Basin (i.e., subsurface sedimentary geology). The intent is to pre-emptively offset the CO_2 emissions that will arise from the production and use of the fuels made from the oil that is extracted using the captured CO_2, effectively rendering the fuels net-zero in lifecycle carbon-intensity (or approximately so).

The deployment philosophy involves modular scalability. Power to operate the plant can be fueled entirely by natural gas or by a combination of natural gas for process heat and externally supplied electricity. Other DAC processes are under development worldwide, some of which use a solid solvent instead of aqueous solutions. Either way, DAC is among the most expensive means of CO_2 capture, which reflects the dilute nature of the CO_2 source – ambient air – compared to concentrated streams from large industrial facilities and combustion-based power plants.

2.1.6 Mineralization of CO_2 – a special case of combining capture with storage

Mineralization of CO_2 is a natural process where the hydrolysis of CO_2 occurs in moist air or water that advances rock chemical weathering, or simply *weathering*. Weathering involves the dissolution of rock – a process in which CO_2 is consumed, resulting in alkalinity production and forms of inorganic carbon. This process, also called mineralization, takes carbon out of the atmosphere and fixes it in a mineral compound. Certain types of rock are quite effective at sequestering CO_2 through weathering. Portlandite is one example:

Hydrolysis of carbon dioxide (i.e., carbonation)	$H_2O + CO_2 \rightarrow H_2CO_3$	ΔH_{298} -614 kJ/mol
Mineralization of Portlandite (rock chemical weathering)	$Ca(OH)_2 + H_2CO_3 \rightarrow CaCO_3 + 2H_2O$	

This is a part of the carbon cycle on earth whereby atmospheric CO_2 is naturally sequestered in mineral form. The figure below illustrates the contribution of rock weathering to regulating atmospheric carbon. The natural pace at which these reactions occur is geological in timescale, and thus too slow to meaningfully mitigate the rate of anthropogenic CO_2 production. However, the process can be artificially accelerated to sequester significant amounts of CO_2 in a matter of minutes under engineered conditions, known as *enhanced weathering*.

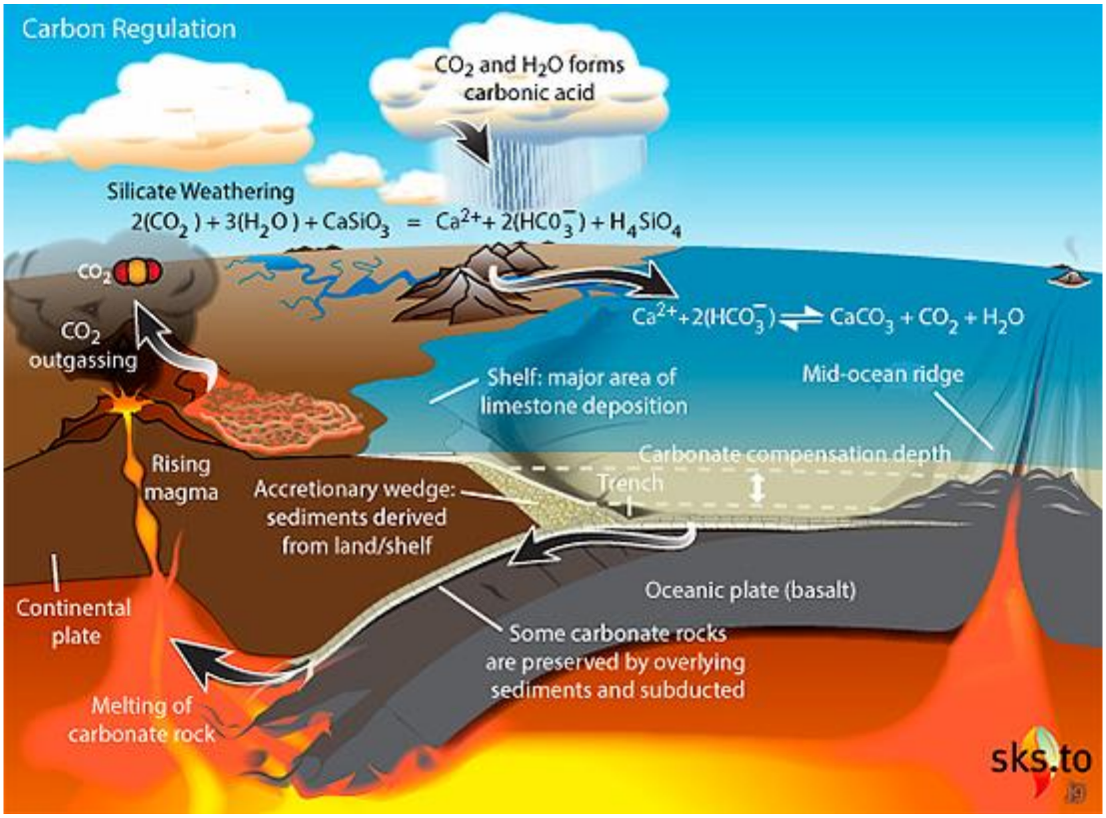


Figure 11: Long Term Carbon Cycle
Source: Garret [8]

The purpose of enhanced weathering – or simply, mineralization – is to mimic and accelerate natural weathering which will increase carbon dioxide removal from air. Natural weathering removes up to 300 Mt of CO_2 annually. Mineralization as an industrial process can capture and store significant amounts of carbon while also generating inorganic carbon products having market value. Silicate rocks are the most suitable for mineralization due to a higher rate of reaction (that is kinetically controlled) compared to other minerals. For natural, suitable rock formations, their physical and chemical characteristics, including void spacing, pore chemistry and temperature, are ideal for large scale mineralization. To achieve commercial target yields, high temperatures and pressures are required, in combination with the use of chemical reagents, to increase reaction rates. Creating and maintaining these conditions has the largest impact on the cost of the process, as it determines the amount of target mineral required to sequester one tonne of CO_2, which can vary greatly between different mineral types.

A further value of CO_2 mineralization is it applicability to treating industrial process wastes. For example, carbonate-cemented products can be reused in engineering applications, which reduces demand for original cementitious products, as well as the associated fuel use. In Europe, carbonated-cement products are already being produced by treating industrial waste using accelerated carbonation, and this form of mineralization has become a growing business.

A major industrial process waste in Ontario that could be used as a feedstock for mineralization is mining tailing; that is the fine wastes from the processing of ore. Tailings from metal and diamond mining could be used in enhanced mineralization processes to capture CO_2 at levels estimated to range from 31 per cent to 125 per cent of the global sector's overall GHG emissions, annually [9]. For scale and context, Ontario's mining sector emits over 533 kt-CO2 eq emissions annually (2020) [10]. Thus, CO2 mineralization using mine tailings as feedstock could conceivably help certain commodity mines reach net-zero emissions operations, while legacy tailings could have new value in ongoing carbon capture efforts. The use of legacy wastes as CCUS process feedstock is called surficial carbonation. Large-scale, commodity-hosting mine tailings are shown in Figure 12 below, with a focus on silicate minerals having enhanced weathering potential.

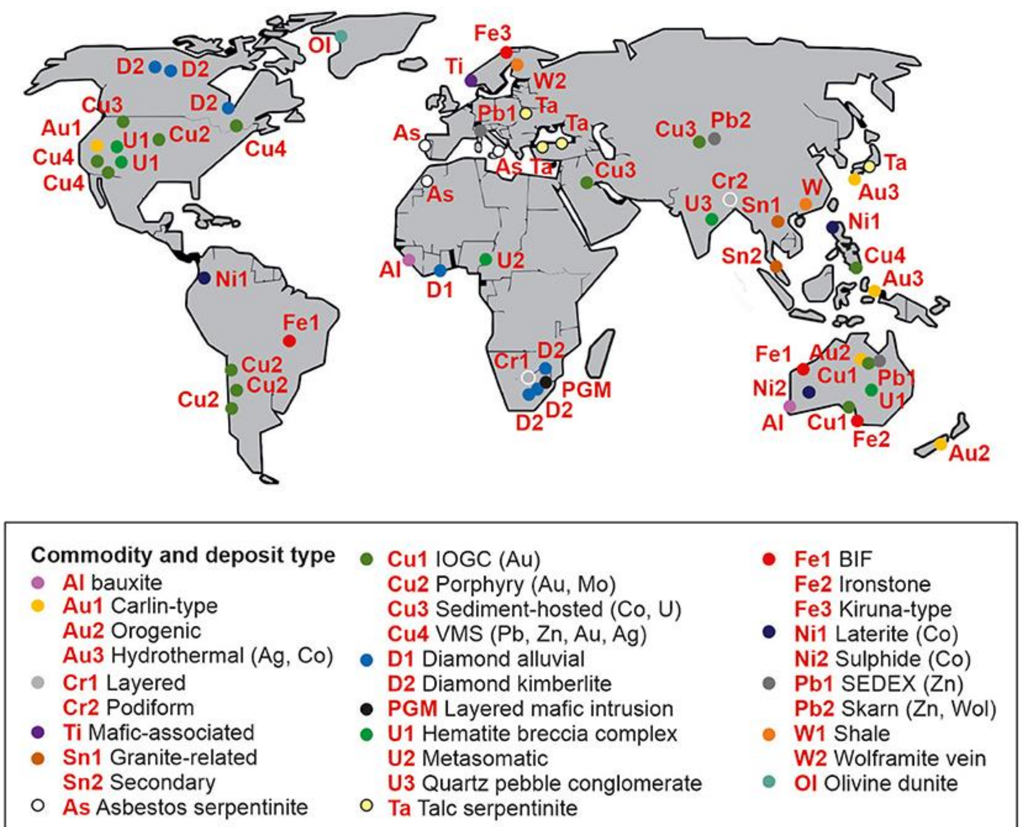


Figure 12: Mining commodities and deposit types having CO_2 mineralization potential
Source: Bullock *et al.* [9]

With further work on mineralization technology, the potential total global amount of CO_2 that can be mineralized in fines waste is estimated to be on the order of one to five gigatonnes (Gt) per year. With the right incentives and policy support, it is estimated that 3.6 Gt per year of CO_2 could be mineralized using construction aggregates alone by 2030 [11]. Based on some projections of global GHG emissions in 2050 under a business-as-usual scenario [12], the abatement by mineralization could amount to 8.4 per cent of the total. Based on this emerging research, field trials in mining settings are advised to validate and realize the potential on a timescale that is less than 50 years, consistent with mid-century climate targets.

The utilization of industrial waste to capture CO_2 and thereby create mineralized products is also attractive because it contributes to the principal of a circular economy and of cross-sector sustainability. For example, steel plants can avoid CO_2 emissions by making low quality aggregates for low-cost concrete. For example, in the United Kingdom, a company called

Carbon8 is using streams of CO_2 from a steelmaking plant to make low-cost concrete blocks. The concrete is at the lower end of the quality spectrum but is suitable for the blocks produced. The silicate waste material feedstock and process equipment to make carbonated aggregates is housed in a portable container, as shown in Figure 13, called the "CO_2ntainer." The Carbon8 solution can take in both gaseous and liquid streams of CO2, enabling multiple emitting facilities to be served by this CCUS solution. Carbon8's CO_2ntainer production of concrete blocks from carbonated materials results in estimated net GHG reductions of 22-34 per cent [13].

Carbon8 represents a type of technology innovation that should be matched with corresponding policy innovation that recognizes the value of the permanent sequestration of carbon it achieves. Commercial viability requires that regulatory frameworks credit operators of such emerging systems for the carbon sequestered. The Government of Ontario's *Red Tape Reduction Plan* makes reference to a framework that will support new means of carbon capture and storage.

Figure 13: Carbon8 - CO2ntainer
Source: Hills *et al.* [13]

To illustrate the geographic range of potential feedstock for CO_2 mineralization in Ontario, based on the use of tailings from current- and past-productive mines, a map of mineral deposits and mine locations is shown in Figure 14, below.

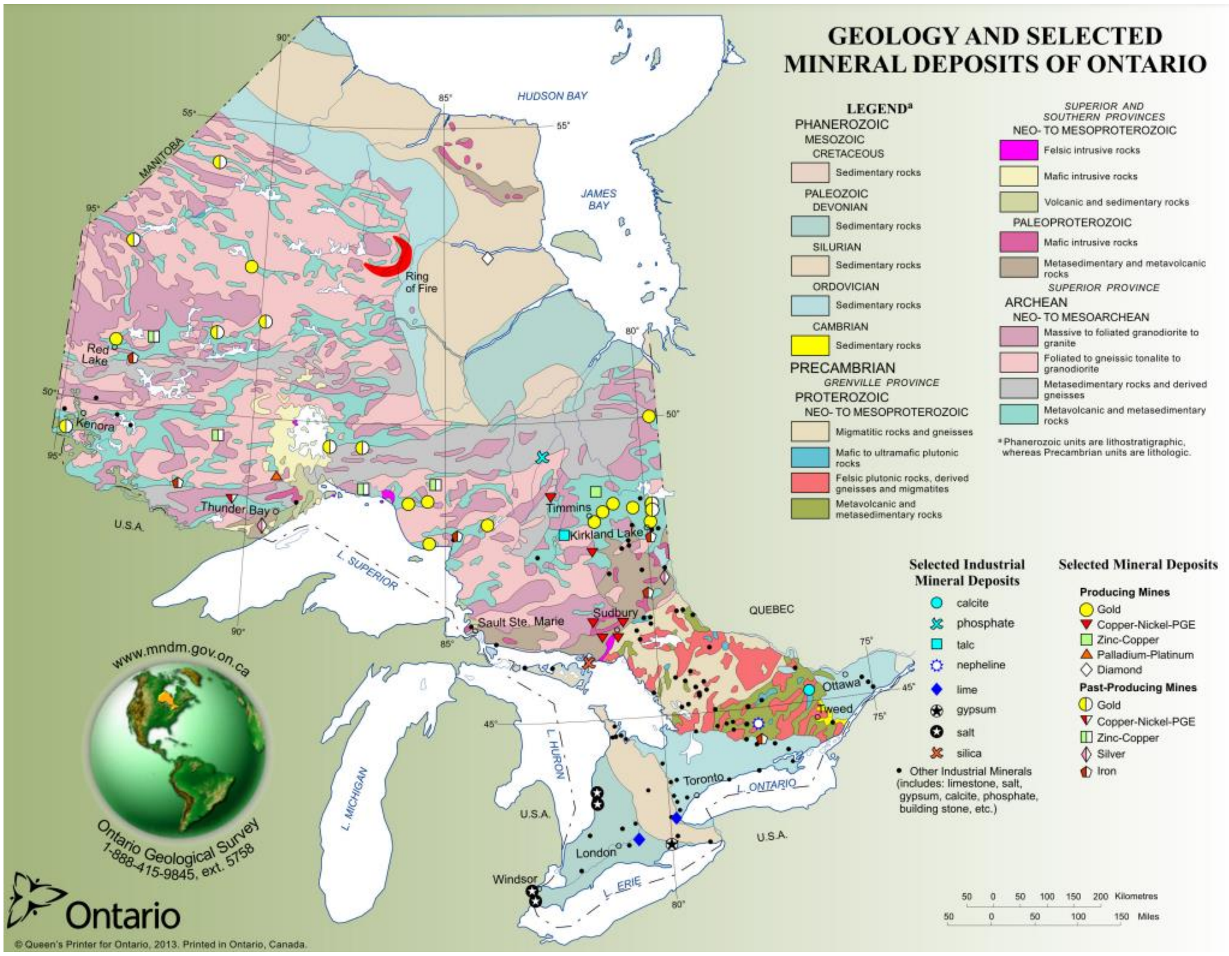


Figure 14: Geology and Mineral Deposits of Ontario
Source: Ministry of Energy, Northern Development and Mines [14]

Figure 15 below shows the enhanced weathering potential of each mineral commodity and deposit type (left axis) and the associated mean mine tailings production (right axis). Of the mine tailings produced in Ontario, D2 tailings (i.e., diamond kimberlite) have the greatest enhanced weathering potential at 550 kgCO_2/tonne, although the production levels are relatively low. Utilizing waste mine tailing from the decommissioned Victor Diamond Mine in northern Ontario (marked by a diamond just east of the Ring of Fire in Figure 14 above) to capture and store CO_2 is, therefore, an opportunity to explore. The other mineral type of significance in Ontario is Cu4 (i.e., lead, zinc, gold and silver). Globally, more than 3,000 megatonnes of Cu4 type commodities are produced annually with an enhanced weathering potential just under 200 kgCO_2/tonne. To determine the enhanced weathering potential associated with these tailings types in Ontario, a quantitative assessment should be conducted.

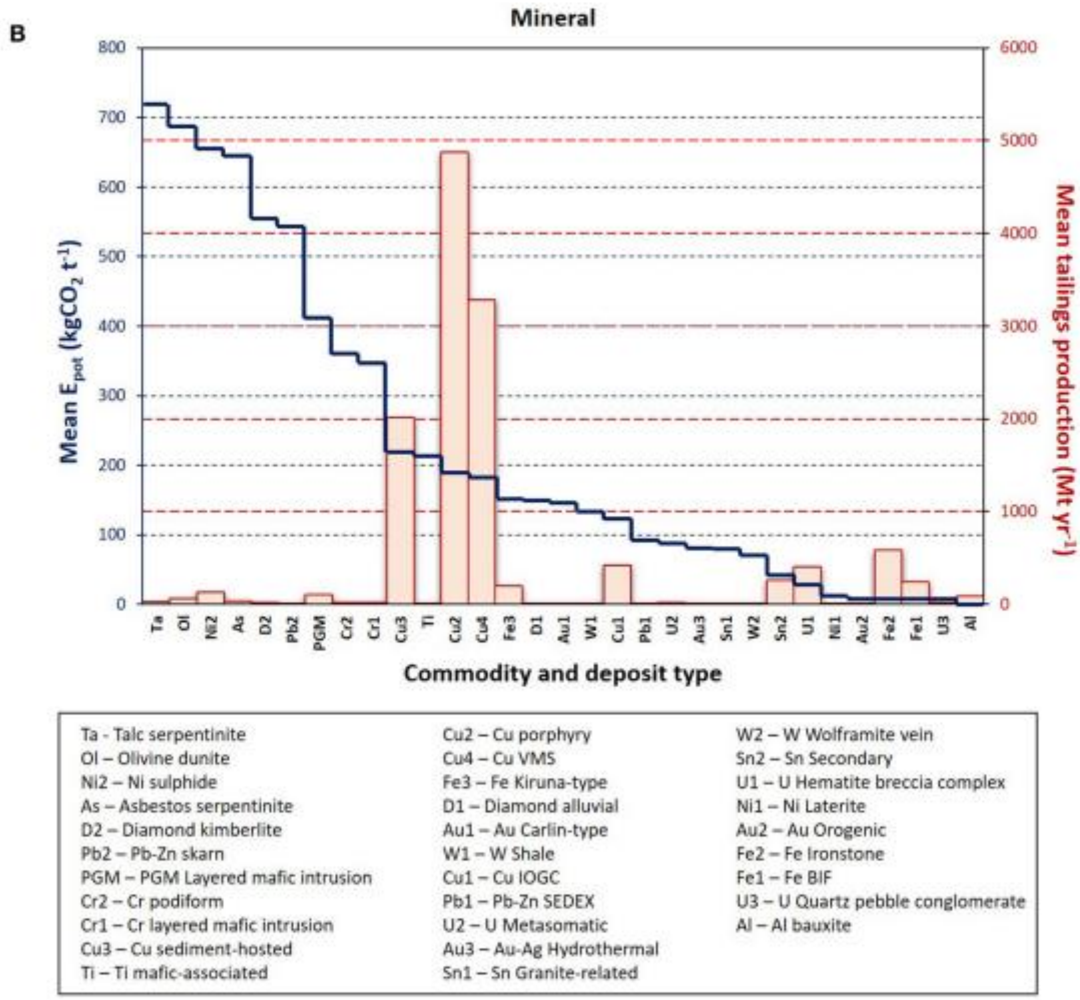


Figure 15: Mineral Weathering Potential and Tailings Production
Source: Bullock *et al.* [9]

Ontario Opportunity: **In-process tailings carbonation at Crawford nickel mine**

The Canada Nickel Company has been developing a novel mineralization process using mine tailings to capture and store CO_2. The new method is called in-process tailings (IPT) carbonation, and the company is considering its application in the forthcoming Crawford open-pit nickel-cobalt mine operation, near Timmins, Ontario, later this decade. The intent is to inject CO_2 directly into the tailings stream as it is generated from ore processing. Complete sequestration of injected CO_2 would take several days, based on the company's published laboratory results, and an estimated 20 tonnes of CO_2 can be captured and stored for each tonne of nickel produced at the mine.

2.1.7 Cost Estimates

The aforementioned special report for the IPCC [4] presented estimates of the costs of CO_2 capture based on best available data in 2005 with ranges of uncertainty. Despite its age, this report remains relevant as its scope is uniquely broad, representing a source of consistent comparison across many different primary industry sectors. Some of these estimates are applicable to the major CO_2 emitters that comprise a large share of Ontario's GHG emissions inventory. A selection of these estimates is reported further below for reference and to facilitate comparisons. Note that most reflect capital and operating expenses but are incremental to the cost of building a new facility *without* carbon capture. The cost of applying carbon capture to existing facilities is expected to be significantly greater.

- *Natural gas-fired power plants*. The cost of electricity production (COE) at modern combined cycle plants having either post- or pre-combustion CO_2 capture solutions with 80-90 per cent less CO_2 emitted per kWh output, would cost 35-70 per cent more than similar plants without CO_2 capture. The range for cost per tonne of CO_2 captured was estimated at US$11-57, which includes compression at the site but not storage or transport. The figures may vary with the price of natural gas, which is sometimes needed to power the CO_2 capture process.
- *Hydrogen production plants*. Due to the concentrated CO_2 streams generated in the production of hydrogen from natural gas, capture rates of 87-95 per cent are achievable, at an incremental cost to the hydrogen product of 18-33 per cent. The cost per tonne of CO_2 captured is estimated as low as US$12 per tonne. Given that separation of CO_2 is already inherent in hydrogen production plants, the incremental cost mainly reflects the compression of the CO_2 for transport or storage.
  - *Ammonia production* does not generate CO_2 directly, but the process requires hydrogen, which can be a source of CO_2 if produced using SMR or ATR systems. Thus, the costs of CO_2 capture ammonia plants is essentially equivalent to hydrogen production plants.
- *Steelmaking*. Integrated steel mills were estimated at US$18 per tonne of CO_2 captured from blast furnaces, but with limits to capturable share of CO_2 emitted. CO_2 capture from DRI was estimated at US$10 per tonne, with much higher capture efficiency if pre-combustion methods are used (e.g., hydrogen-based DRI).
- *Wood pulp mills*. Capture of CO_2 from biomass-fired boilers is estimated at US$34 per tonne.
- *Ethanol plants*. CO_2 from the fermenting of sugars can produce very pure streams of CO_2, yet incremental capture costs are estimated at US$53 per tonne. The higher cost is likely due to less consistent operations compared to, say, a baseload power plant.
- *Biomass power plants*. Steam turbine power plants fired by biomass typically operate on smaller volumes of feedstock, so CO_2 capture costs do not benefit as much from scales of economy as would larger power plants. The IPCC report references a 24 MW integrated biomass gasification combined cycle power plant having an incremental cost of US$70 per tonne, compared the same plant without CO_2 capture.

Carbon Engineering reports the cost of a 1 Mt-CO_2 per year DAC facility as having a levelized cost that ranges 94-232 US$ per ton-CO_2. When the captured CO_2 is compressed for delivery at 15 MPa, the energy input requirements are either 8.81 GJ of natural gas, or 5.25 GJ of natural gas plus 366 kWhr of electricity, per ton of CO_2 captured. In a 2022 report by the International Energy Agency, deployment and ongoing innovation is expected to reduce DAC system costs to less than 100 US$ per tonne-CO_2 [15].

Note that the above estimates represent the cost of CO_2 captured, which is different from the cost of CO_2 emissions *avoided*. The latter is used to account for differences in the efficiencies of capture technologies. It reflects the costs of reducing CO_2 by one unit while providing the same amount of useful product. For harder-to-abate emissions sources, particularly in which a lesser share of the CO_2 stream is successfully captured and stored, the cost of avoided CO_2 can be higher compared to more easily captured, concentrated streams.

The International Energy Agency summarizes its 2019 estimates of the cost of CO_2 capture in the following chart. Dilute sources of CO_2 are in light-blue, such as flue gas, while more concentrated sources of CO_2, such as CO_2 captured at an SMR plant, are in dark-blue. As discussed earlier, more concentrated streams are capturable at lower cost. Note that the estimated cost ranges presented here are consistently higher than those of the earlier IPCC report, representing a wider system boundary, yet the relative differences between sectors are generally preserved.

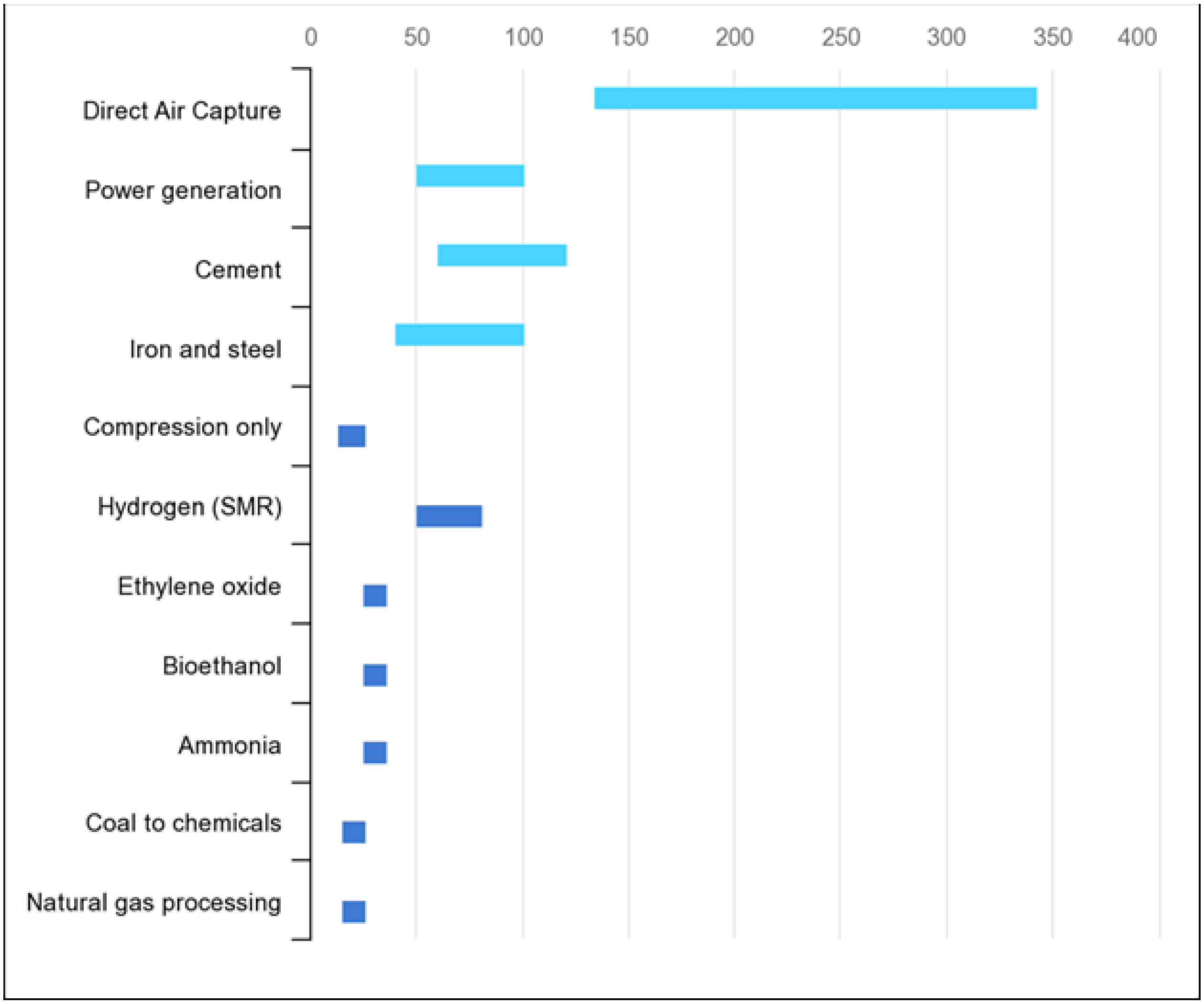


Figure 16: Levelized cost of CO_2 capture by sector (USD/tonne) and initial CO_2 concentration, 2019
Source: IEA 2022 [16]; License: CC BY 4.0 [17]

2.2 Geological Storage of Captured Carbon Dioxide for Permanent Sequestration

The goal of storing captured CO_2 deep underground is permanent sequestration, such that it will not leak back into the atmosphere. Once the CO_2 has been captured at a source, it must be prepared for injection into a suitable geology. This involves pressurizing the CO_2 for transport and treatment (e.g., drying, purification) of the gas prior to injection. Pipelines are a common form of CO_2 transport infrastructure, suitable to the relatively large mass flows that would come from power plants and industrial facilities. At about 30 degrees Celsius and 74 bar (7.4 MPa), CO_2 gas becomes a supercritical fluid. The energy needed for this phase change is low compared to many other industrial liquefaction activities. Being more dense, supercritical fluid CO_2 is more economical for transport by pipeline. The technological elements of CO_2 transport systems are commercially established, and pipelines are currently moving captured CO_2 to injection facilities in Canada, the U.S. and around the world.

The uncertainty lies with the geological reservoirs that can accept the injection of large volumes of CO_2 for permanent storage. The location and nature of these subsurface formations is often guessed at, but not always known with certainty. The reason is economic; geological formations that are rich in oil and gas have commercial value and are thus well-surveyed and understood. Since injection of CO_2 extends the productive life of many oil deposits, there is a financial motivation to learn the flow dynamics and to monitor the movements of CO_2 underground. By contrast, in Ontario, the potential for large-scale geological storage of CO_2 has not been proven through direct trials in the past, simply because there has not been a compelling reason to do so. However, the rising cost of CO_2 emissions and the global challenge of climate change mitigation is pressing government, industry and academia to take stock of the need and the opportunity.

This section synthesizes the prevailing assumptions about favourable geologies for CO_2 storage in Ontario and their proximity of major point-sources of CO_2, which could facilitate carbon capture and storage (CCS) solutions. While this is a start, actual field survey and trials will be required to confidently characterize the potentials for CCS within Ontario and for Ontarians.

2.2.1 Prospective Geologic CO_2 Storage Opportunities in Ontario

An ideal geological formation for CO_2 injection and permanent sequestration has at least three characteristics:

1. *Depth*. At around 800 metres in depth, the pressure and temperature conditions will maintain CO_2 in a supercritical fluid state, due to the weight of the rock and overburden above. In this state, more CO_2 can be stored for the same pressure.
2. *Porosity*. The pore space within the formation is a primary determinant of the amount of CO_2 that could be accommodated and stored. Sedimentary rock formations are candidates for good porosity, as they are formed from the deposition of granular sediments. With time and pressure, the grains consolidate and cement together to form various types of rock (e.g., sandstone, limestone, shale, etc.). This rock is akin to a sponge, with the volume of void space between the grains as a measure of its porosity.

3. *Permeability*. The interconnectedness of the pore space can determine the ease with which fluid can flow through the rock. An ideal formation for CO_2 storage should have sufficient permeability to allow the supercritical fluid to disperse outward from a point of injection, occupying as much of the available pore space as possible. Some sedimentary rock has high porosity but low permeability, being composed of finer grains (e.g., shales), while others are coarser-grained and thus have higher permeability (e.g., sandstone). An ideal site would also have an impermeable layer on top of the permeable storage medium; that is, a caprock, which prevents seepage (provided there are no fractures or bore holes that provide a path for leakage upward).

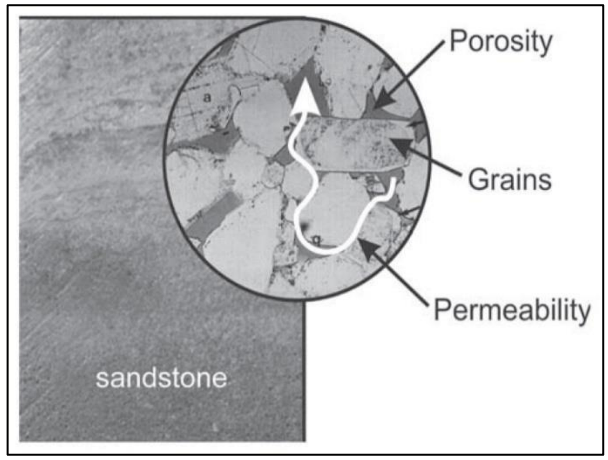


Figure 17: Porosity and permeability within sandstone rock
Source: Carter *et al.* [1]

Much of Ontario's geology is Precambrian rock close to the surface or even fully exposed to atmosphere, referred to as the Canadian Shield. The sedimentary overburden may be porous and permeable, but it is thin, shallow and is also a major source of groundwater, so there are few opportunities for CO_2 injection and sequestration. However, there are some significant basins in Ontario to its north and south where deep layers of sedimentary rock have formed on top of the Precambrian base. The Moose River and Hudson Bay basins have some promising characteristics but are considered either too shallow or too remote from the major CO_2 sources in the south to be developed into a practical storage, when compared to the Michigan and Appalachian basins, which have both depth and proximity to most of Ontario's industrial emissions. A ridge of

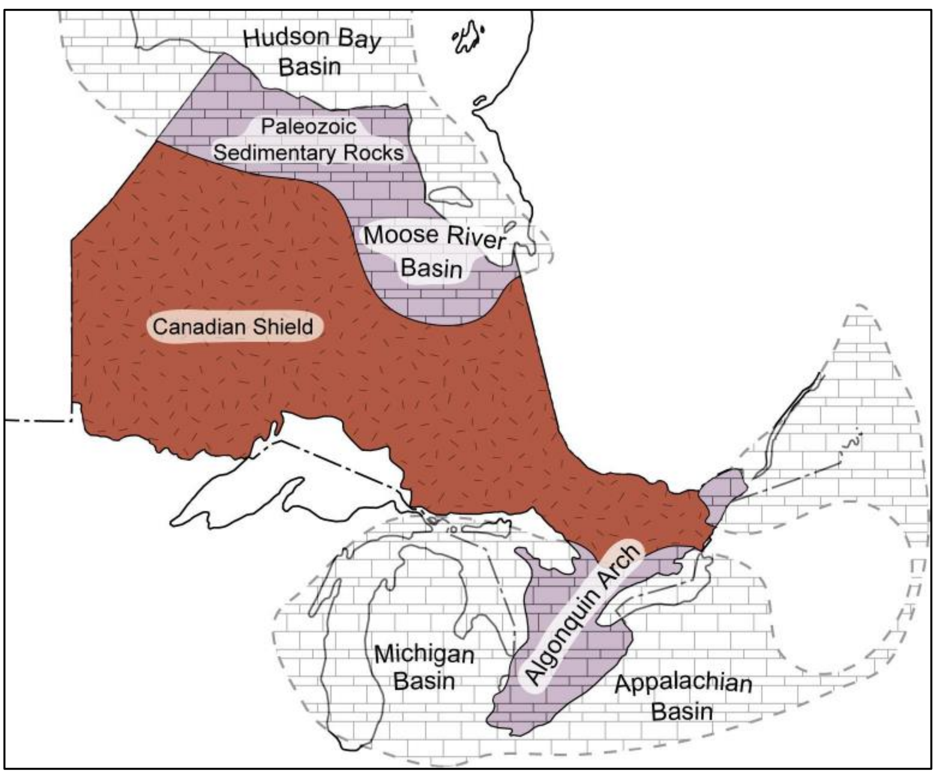


Figure 18: Major rock types and sedimentary basins in Ontario
Source: Carter *et al.* [1]

Precambrian rock, known as the Algonquin Arch, divides the Michigan and Appalachian basins, such that the depth of the sedimentary rock increases westward and southward from the ridge. To the extent of Ontario's borders, the depth of the sedimentary rock increases to approximately 1,400m below Lake Erie and at the southern tip of Lake Huron, deepening further into U.S. territory.

Figure 19 shows the geologic cross section across the Algonquin Arch in southern Ontario. This illustration (modified from Armstrong and Carter, 2006) shows the thickness of Paleozoic sedimentary rocks in metres. Paleozoic rock units thicken to the west and south on either side of the arch.

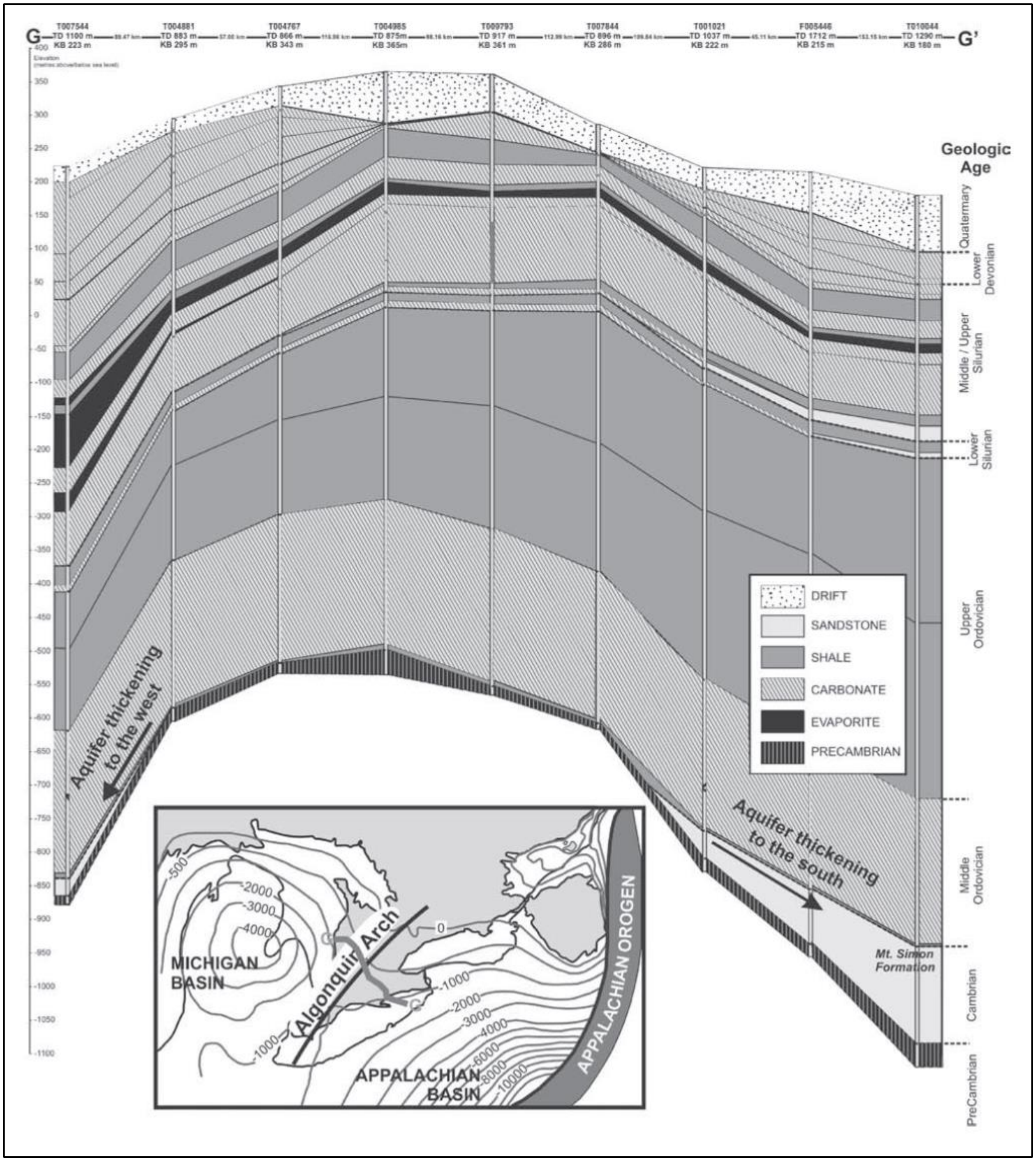


Figure 19: Geologic cross section across the Algonquin Arch
Source: Carter *et al.* [1]

The depths of these sedimentary basins are stratified by numerous layers of distinct types and ages of geologies. The lowest layers are composed mainly of Cambrian sandstones, suitably porous and permeable for saline (i.e., saltwater, brine) to thoroughly saturate the formation. A layer of Upper Cambrian sandstone (resting just above the Precambrian base) hosts the saline aquifer known as the Mount Simon Formation. It extends throughout the Michigan and Appalachian Basins, under southern Ontario and reaching depths much greater than 800m. The formation thickens on either side of the Algonquin Arch, as the basins deepen, providing the volume and pressure needed for significant sequestration potential. At these depths, supercritical CO_2 will dissolve into the saline and, eventually, undergo reactions to become fixed in a mineral phase with the surrounding materials, thus permanently sequestering the CO_2 in the formation. The dissolution and mineralization processes take time – from hundreds to thousands of years. Fortunately, the formation is overlain by non-porous limestones and impermeable shales, providing a caprock that is expected to keep the CO_2 in the sandstone formation as these solubility and mineral trapping processes progress. [18]

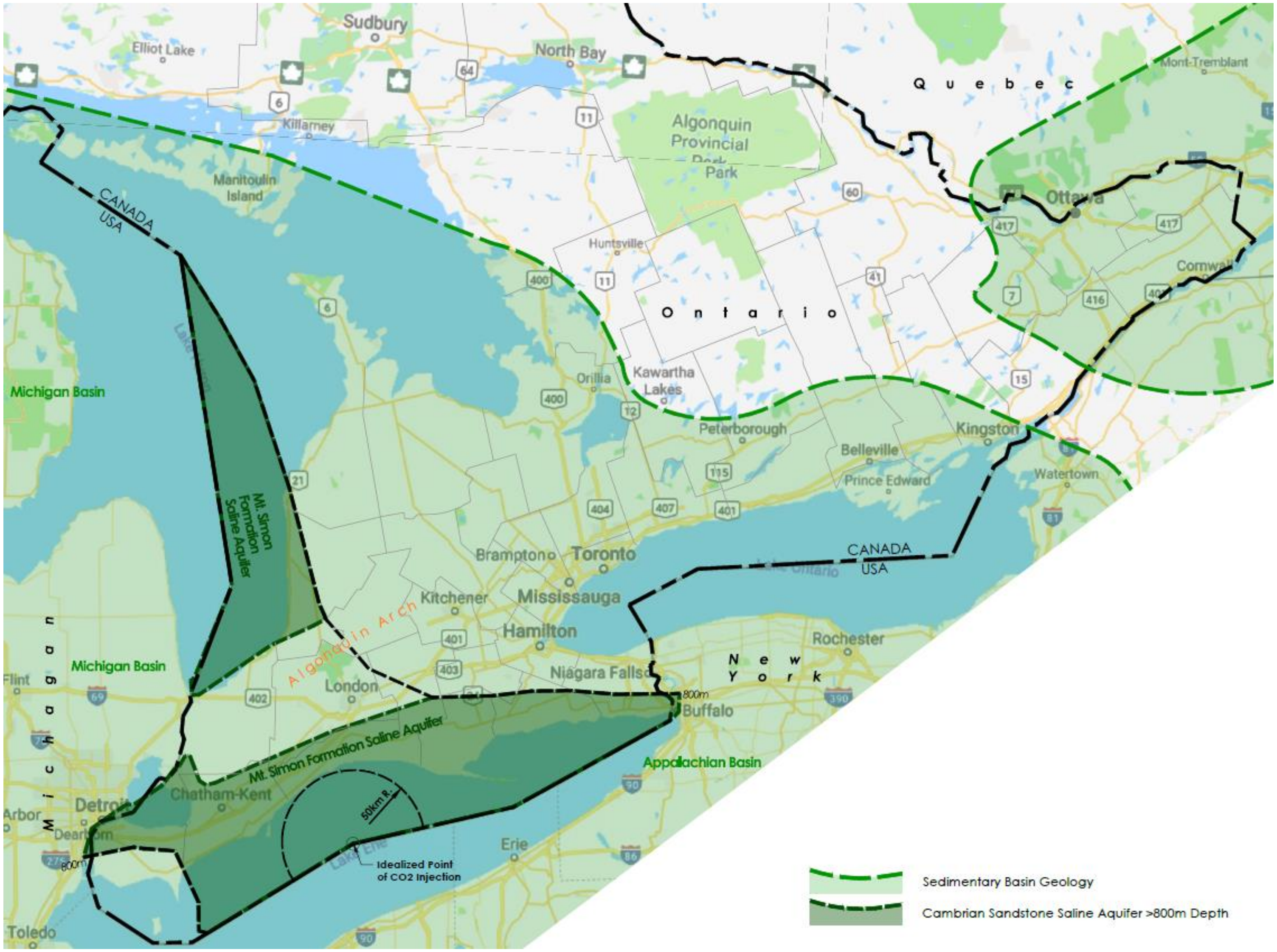


Figure 20: Mount Simon Formation in Southern Ontario
Source: Adapted from Carter *et al.* [1]

The map in Figure 20 shows the areas within Ontario's borders where the Mount Simon Formation has the depth to make CO_2 storage promising. The CO_2 storage potential of the saline aquifer was estimated by Shafeen et al. (2004) for the northern and southern zones, at 289 Mt and 442 Mt, respectively. This was based on an assumed average thickness of 31m for the sandstone and a 10 per cent porosity factor. However, a proper program of direct testing and primary data gathering is needed to properly characterize the formation, such that accurate estimates can be made, since there are many physical factors that could limit (or facilitate) total storage potential, as well as the rate at which CO_2 can be injected.

For example, within the formation, there could be areas of low permeability in the strata that isolate and fragment pockets of good porosity, making them inaccessible and reducing the total storage potential. Depending on the size and geometry of the pores, the surface tension of the saltwater itself may block the flow of the supercritical CO_2 through small pore spaces, limiting the outward spread from the injection point (a measure of the formation's capillarity). This spread can be considered as a plume of supercritical CO_2, which will advance more quickly through channels of greater permeability under a certain injection pressure. Since supercritical CO_2 has lower viscosity than the saline in which it's injected, it will not permeate through a porous formation across a consistent front, but in a pattern of viscous fingering due to the unstable interface between different fluids (i.e., Saffman-Taylore instability), in this case between CO_2 and saline. As well, supercritical CO_2 is less dense than saline, so it will naturally rise to the top of the formation (i.e., the caprock seal), meaning the upper pore volume in the formation will saturate first (known as gravity override). The salinity of the aquifer itself must also be confirmed, as this will govern the solubility of the CO_2 for permanent storage. Understanding the nature of these many factors within the formation will inform the best placement of injection points (i.e., how many and where) and operating pressures, to realize the maximum CO_2 sequestration potential within the reservoir.

Due to the buoyancy of the supercritical CO_2, a logical assumption for the ideal point of injection is at the deepest, thickest part of the Mount Simon Formation accessible from within Ontario's territory. This coincides with offshore locations in Lake Erie and Lake Huron but, practically, this may mean the nearest on-shore points. The plumes of supercritical CO_2 injected in these areas would likely spread eastward from a Lake Huron injection point and northward from Lake Erie, following the upward slope of the formation toward the Algonquin Arch.

Using data from CO_2 injection projects around the world, hypothetical plume migrations could be modeled to inform consideration of injection site selection, but actual tests must eventually be conducted to determine how far the CO_2 would travel before fully dissolving and becoming fixed in the saline aquifer. Plume migration is important to understand; if it spreads too far the CO_2 could rise above the depths at which it remains a supercritical fluid, vaporize and possibly escape through any fractures or faults that may exist in the above sedimentary layers, or through wellbores from previous oil and gas exploration.

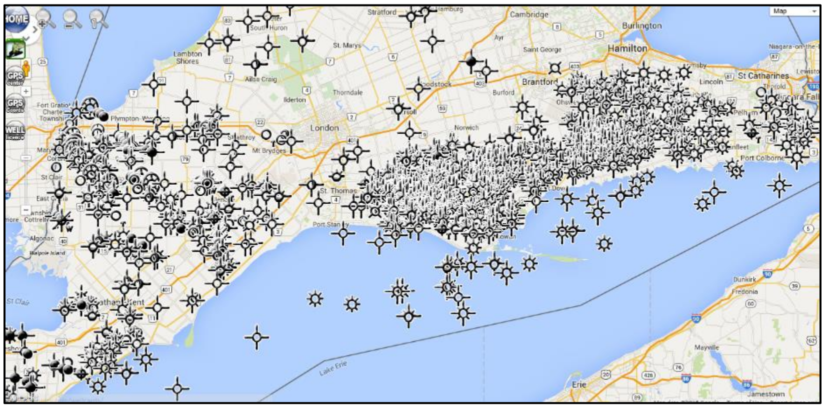


Figure 22: Known wellbores in Southern Ontario
Source: Ernst [51]

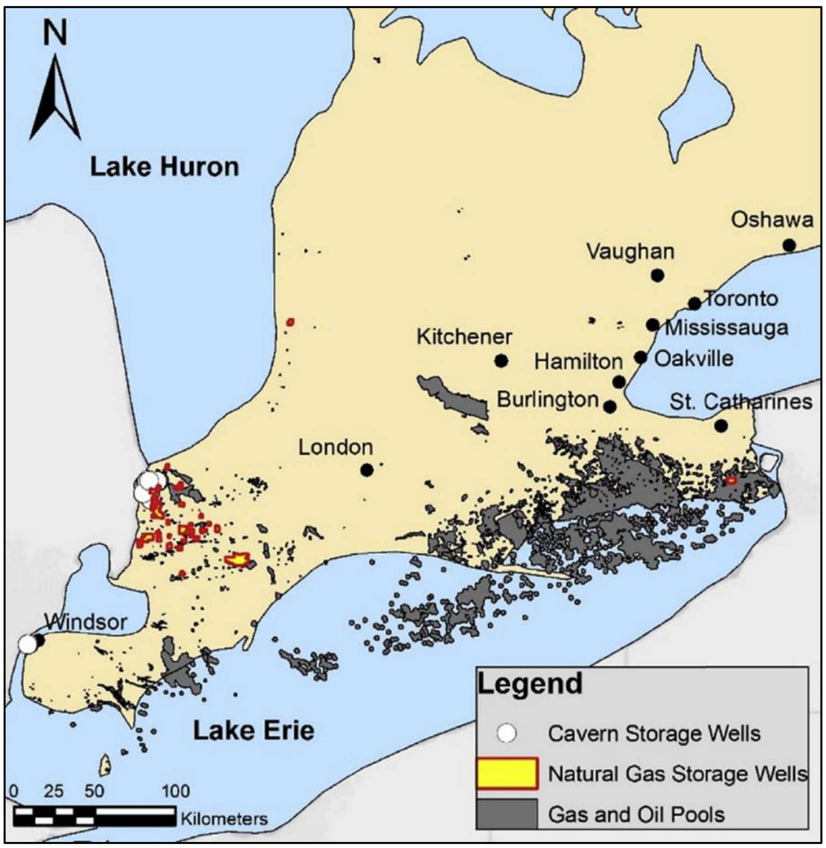


Figure 21: Preliminary assessment of underground hydrogen storage sites in Ontario, Canada
Source: Lemieux *et al.* [52]

Wellbores must be considered in prospecting for subsurface CO_2 storage. Since the mid-1800s, more than 50,000 wells were drilled in Ontario, some of which are known to penetrate the Cambrian sandstone though the majority do not. More than 2,000 wells are currently producing oil and gas in Ontario, including in Lake Erie offshore. Properly retired wells are supposed to be tightly sealed and monitored, but there remain an unknown number of unregistered, abandoned wells that are unsealed. Regardless, current standards for wellbore sealing were not developed with long-term CCS in mind. Depending on where CO_2 is injected, there is a risk that the advancing plume could eventually find a path back to the surface through one of these wellbores. This risk can be mitigated by firstly avoiding areas where oil and gas were found in the Cambrian having a correspondingly higher concentration of wells. CanmetENERGY at Natural Resources Canada works with industry, academia and leading stakeholders, such as the Wellbore Integrity and Abandonment Society, to fill the gaps in knowledge through field surveys and site assessments in Ontario.

In some cases, depleted oil and gas fields in Ontario could serve as CO_2 storage reservoirs. Some of these fields occur in the Cambrian sandstone, while others are at shallower depths. The caprock that originally trapped these pools of petroleum might also be capable containing injected CO_2. Indeed, within the Middle and Upper Silurian carbonate formations are uplifts or peaks that were once productive sources of oil and gas. Now depleted, some of these peaks are currently used to store natural gas to accommodate seasonal swings in demand. The Dawn Hub near Sarnia is the most significant of these, where a cluster of peaks forming a kind of pinnacle reef structure are used as network of natural gas storage reservoirs.

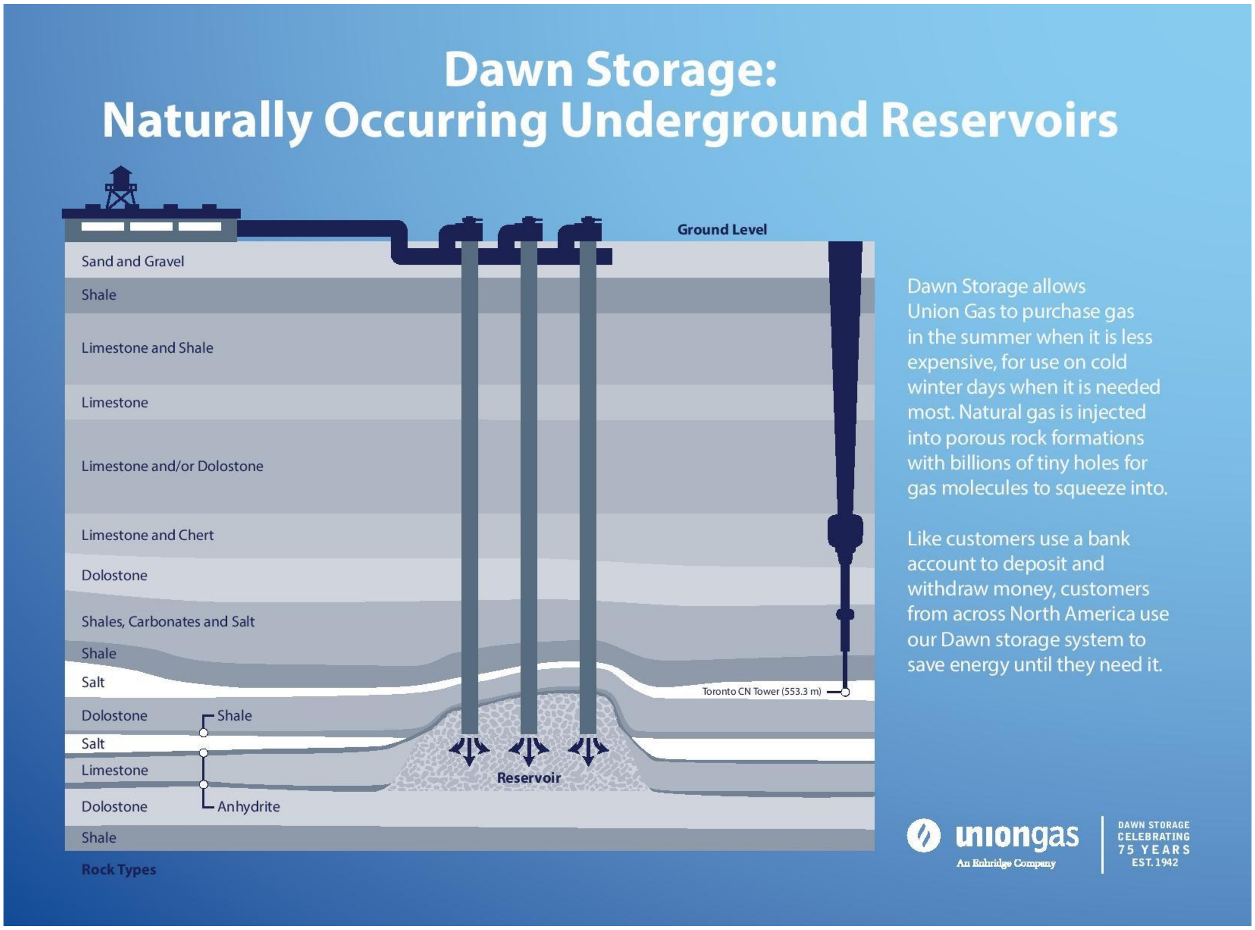


Figure 23: Naturally occurring underground reservoirs for storing liquids and gases
Source: Ontario Society of Professional Engineers [19]

While these depleted reservoirs may have capacity for temporary storage of petroleum, their potential for permanent sequestration of CO_2 emissions – in the volume needed to mitigate industrial sources in Ontario – is limited. Compared to the deep saline aquifer prospect described above, the problem of unsealed wellbores is even more acute with depleted reservoirs. This further limits the potential for CO_2 storage (unless abandoned wells are found and capped, at some expense; ~$200,000 per well). Nonetheless, use of the right depleted reservoirs could add marginally to the province's overall potential for storage. Ideal prospects would be under-pressurized reservoirs, allowing more CO_2 to be accumulated before the breakthrough pressure of the caprock is reached.

Salt caverns are another geological formation that are used for temporary natural gas storage. Salt deposits are solution mined, creating a cavity in the formation in which oil and gas are stored. The surrounding salt walls in the cavern are impermeable to CO_2, which prevents leakage. However, in Ontario the known salt formations are often too shallow and thus have insufficient pressure to store CO_2, compressed, in practical amounts. Deeper salt deposits may exist under Lake Huron, but these remain to be discovered. The impermeability of salt formations makes mined caverns an attractive temporary storage solution for hydrogen gas, which is discussed later in this report.

The forgoing discussion, as a synthesis of literature on the subject reviewed and consultations with geologists, points to the relatively thin layer of Cambrian sandstone (i.e., the Mount Simon Formation) as the most promising storage medium for permanent sequestration of CO_2 in Ontario. This reflects a widely held consensus of experts in academia, government, and industry. The subsection that follows addresses the factors that influence the selection of host sites for CO_2 injection activity.

The capacity estimates referenced earlier for the Mount Simon Formation sum to 731 Mt of CO_2 storage, but in the absence of data gathered through direct, comprehensive survey work, the actual may range from well under than 100 Mt to well more than 1,000 Mt. The 50 largest, point-sources of CO_2 emissions in Ontario sum to nearly 40 Mt annually. Hypothetically, if all these emissions were captured for sequestration within Ontario, the formation could become saturated within with a just few years. However, this assumes an unrestricted rate of CO_2 injection and a physical ability to service all major emitters with CO_2 offtake services and transport to Mount Simon Formation injection facilities. These are impractical assumptions, as there will be limits to the rate at which the saline aquifer can absorb supercritical CO_2 under pressure and some emitters may be too far from an injection point to be economically serviced. So, the period of continuous, large-volume injection could run for a number of decades. Eventually, however, the potential for permanent sequestration will be exhausted.

For reference, The North American Carbon Storage Atlas 2012 [20] included a mid-range estimate of the total potential for geological CO_2 sequestration within Ontario at roughly 1 Gt, which could be saturated after 30 years of continuous injection. This is based on capturing CO_2 emissions from facilities emitting more than 100 kt/yr; emissions from these facilities summed to approximately 41 Mt in 2008 (the data-reporting year for the publication). Oil and gas reservoirs were assumed to receive injected CO_2 for roughly 5 years, while saline aquifer formations could operate for 25 years before saturation.

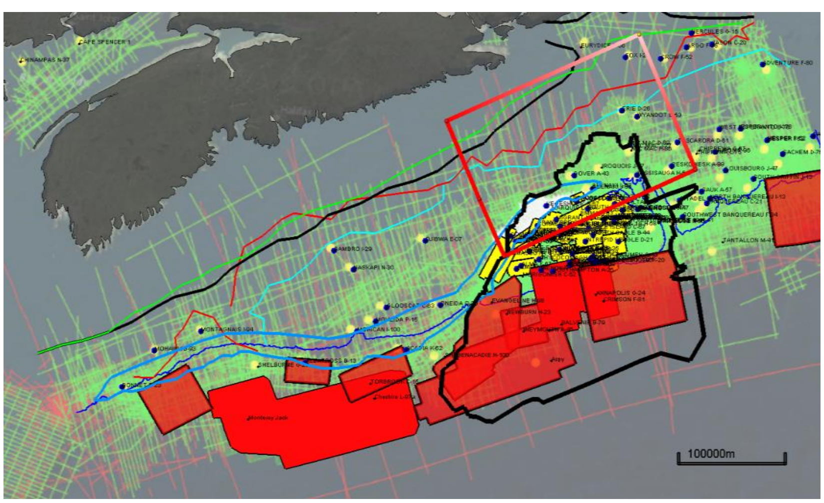


Figure 24: Data visualization of assessment of Scotian Shelf for CO_2 storage
Source: Wach et al, and Richards, F.W. **[21]**.

This raises the prospect of exporting CO_2 by pipeline, as many Ontario facilities may need a storage solution that last more than a few decades. Undersea saline aquifers off the shores of Atlantic Canada could have enormous CO_2 storage capacities. Geological modelling of the Scotian Shelf indicates potentials ranging from at least 10 Gt to more than 1,000 Gt [21].

Similarly, far more of the Cambrian sandstone formation of the Michigan and Appalachian Basins exists under the U.S. Midwest. The saline aquifer is deeper and more of it is accessible from the surface. Estimates place the storage this capacity at more than 475 Gt, under Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. Conceivably, CO_2 captured in Ontario could be transported to injection sites in the U.S. that may exist.

As part of the National CCUS Assessment Framework, the CanmetENERGY-Ottawa team has developed a comprehensive technoeconomic optimization model that calculates least-cost transportation modes for moving captured CO_2 to storage sites based on range input variables, and generates total capital and operating expenditures, as well as technical details to manage throughput. The image below (Figure 25) is an example of scenario simulated by the model. The red circles represent the location and size of fossil fuel combustion emission sources; green are biogenic sources. The pink lines are railways and the heavy black represent CO_2 pipelines capable of more than 200 Mt of annual throughput. A rule-of-thumb among analysts is that large-emitting facilities (say, 3 Mt or more) can be directly served by pipelines, economically, while smaller emitters could rely on railway service to transport their captured CO_2 (an estimated capacity of approximately 100 tonnes-CO_2 per railcar). The scenario illustrates how CO_2 could be gathered from disparate sources and funneled into trunk pipelines that terminate at remote, subsurface injection facilities.

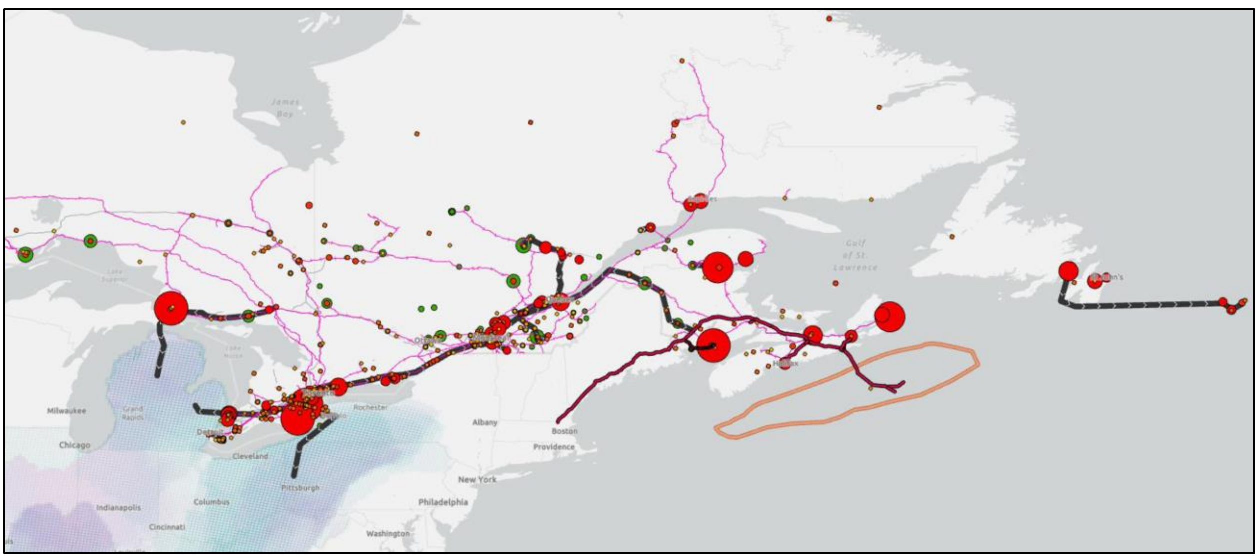


Figure 25: CO_2 Gathered from Disparate Sources and Funneled into Trunk Pipelines that Terminate at Remote, Subsurface Injection Facilities
Source: Hughes [53]

To achieve deep decarbonization of industry in Ontario, infrastructure works at this scale must eventually be confronted. The larger the network, the lower the overall cost of CO_2 capture and storage for all parties relying on the system. However, in the timeframe of this report (10-15 years), in-province CO_2 storage in the Mount Simon Formation and depleted oil and gas reservoirs is the focus of the analysis.

2.2.2 Characteristics of Prospective Host Sites for CO_2 Injection and Storage

CSA Z741-12 is a national standard for geologic storage of CO_2, and it is applicable to storage in saline aquifers and depleted oil and gas reservoirs. The standard provides guidance for a range of operational aspects, including site screening and selection, community engagement, facility design, conditions for injection, operation and maintenance, site closure and long-term stewardship, risk management, and GHG quantification and verification. The table below highlights the tasks that must precede site development, namely site screening and selection and site characterization. This is to determine whether the sites have capacity to accept the intended amount of CO_2, injectivity to accept CO_2 at the required rate and integrity of the caprock to ensure CO_2 remains sealed.

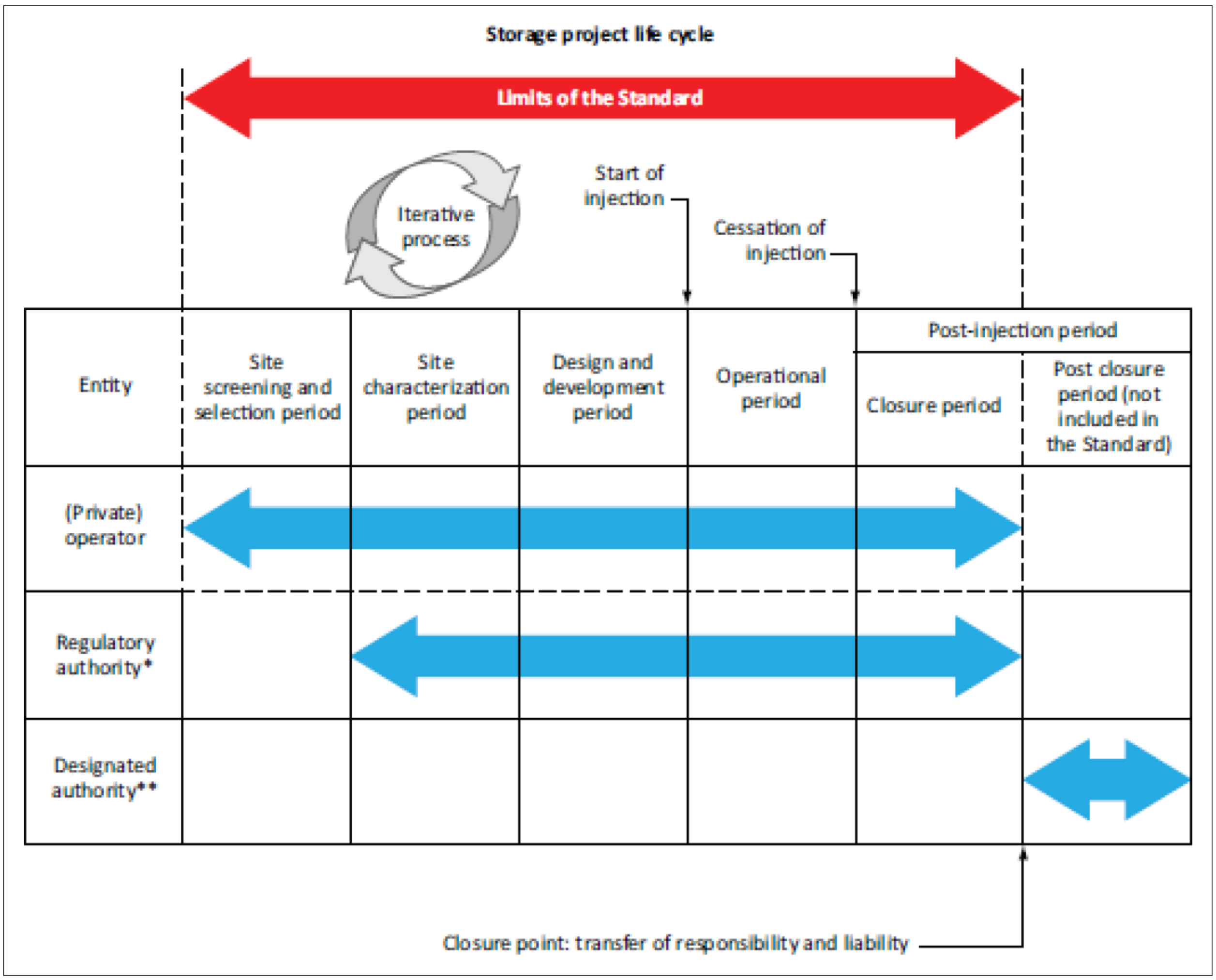


Figure 26: CSA Z741-12 and requirements for geologic storage
Source: From presentation by Sean MCoy, 2014 [22]

For a prospective site, the injectivity index is given by

$$J = \frac{q}{\Delta p}$$

where q is the injection rate and Δp is the difference between the static pressure within the formation, p_f, and the bottom-hole pressure, p_{bh}. Assessing injectivity starts with a review of available data, such as existing borehole records, seismic survey reports and stratigraphic representations. If the review is promising, the next step is to conduct exploratory borehole drilling to produce cores samples for testing and analysis (water sampling can occur in parallel during this step). Testing within the borehole can follow, including stress testing. Finally, laboratory testing yields detailed information about the formation, which can be input to geological models to simulate how CO_2 will propagate from points of injection, and how the formation will react.

Examples of existing injectivity index, i.e., J values, measured in tonnes/year/kPa, in Cambrian sandstone in North American range from approximately 25 to 150. A higher index represents lower pressure difference at the bottom of the well, or a higher injection flow rate, or both. A constraint is that p_{bh} must remain lower than a level at which the formation would fracture (or a regulatory limit). Injection at greater than 800m depths allows operating pressures to approach 9 MPa – sufficient to maintaining the CO_2 as a supercritical fluid, which is key to its permanent sequestration in the brine. It may be that horizontal drilling into the sandstone formation allows for more targeted dispersal of the injected CO_2 from numerous sites along the borehole, increasing the rate of injection.

For the purpose of illustration and analysis, Carter et. al [1] mentioned (after Shafeen et al [23]) a point of CO_2 injection in Lake Erie along the Canada-U.S. border. This point is close to major emitting sources while being over the deepest, thickest parts of the Mount Simon Formation under Canadian territory. Oil and gas drilling operations on Lake Erie is an established practice. There are more than 500 active gas wells operating offshore, more than a dozen horizonal wells operated from land and 1,500 km of natural gas pipelines on the lakebed. So, injection wells drilled in the lake bottom and connected by pipeline to the shore, or to a permanent platform on the lake surface, is technically feasible. This point of injection (or some proximate location onshore) may well be the most promising site to evaluate and characterize as part of Ontario's long-term, in-province CO_2 storage solution.

Depleted gas reservoirs are a shorter-term storage prospect, but they might be quicker and less costly to realize. This is because many such oil and gas fields are close to large emitters, and they are already well-characterized based on years of productive operations. Furthermore, significant portions of the existing pipeline network that interconnects these reservoirs may be adaptable to the transport of CO_2. However, these upside benefits of using developed oil and gas fields for storage may also represent a downside risk, in that many unsealed, unmonitored, legacy wells could penetrate into the formations, providing possible paths of escape for the injected CO_2.

The prospective injection sites described above are shown on the map in Figure 27, below. To be clear, these are not qualified sites – these are merely represented for hypothetical analysis.

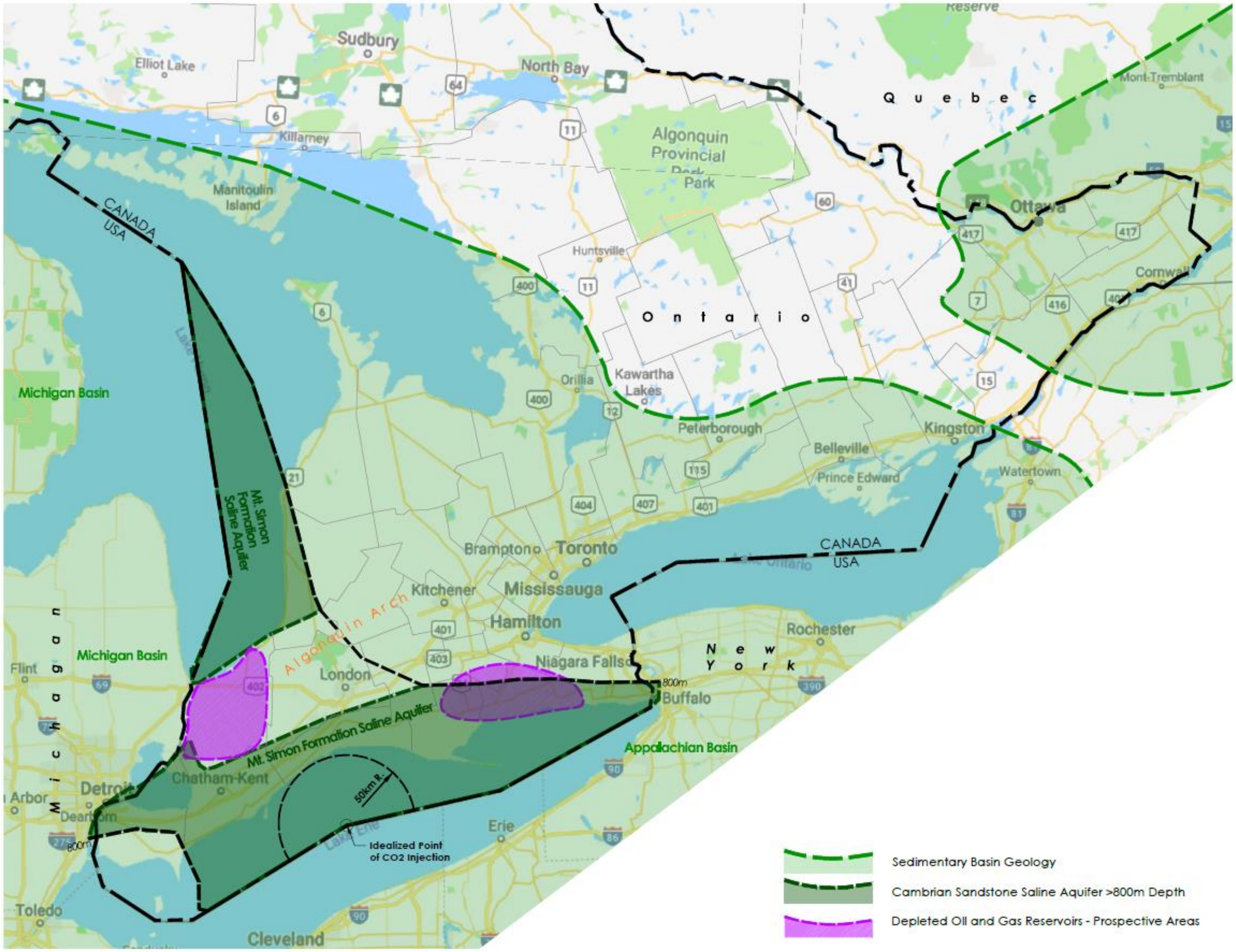


Figure 27: Idealized CO_2 Reservoirs and a Hypothetical Injection Point

Once a site is assessed as suitable for CO_2 injection, the construction of the facility and well will follow established practices and standards. Figure 28 provides a generalized illustration of well construction. Layers of concentric pipe are typical, and the selection of materials is determined by the depth of the well and stresses and seismicity of the local geology. The intent is to maintain integrity of the well and the injection operation, to ensure no contamination of drinking water resources or inducement of seismic activity (a concern with deeper wells). Various classes of well are defined for specific purposes.

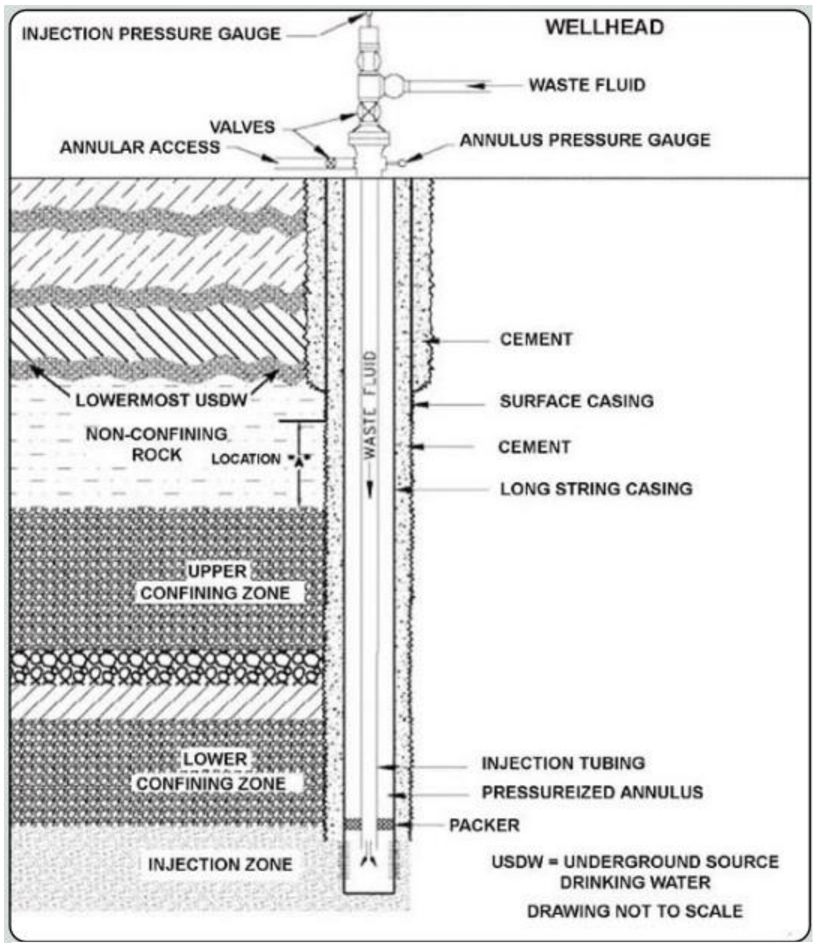


Figure 28: General Design for an Injection Well
Source: Goodin [58]

During operation, injection wells must be continually monitored for performance and verified against targets. This requires a comprehensive program of measurement, monitoring and verification for the site. The program should gather data and conduct analysis to report on the geomechanical stability of the injection area, the operational integrity of the wellbore and its effects on the surrounding formations, the rate of CO_2 absorption and any evidence of CO_2 escape or unintended movements into other strata. Indicators must be chosen for monitoring, which can vary by site, but would generally include subsurface (e.g., geo-mechanical indicators such as pressures, temperatures, micro-seismicity), surface and near-surface (e.g., changes of deformations in the surface area around the site), and atmospheric indicators. The following image (Figure 29) represents a scope of indicators under regular surveillance as part of a measurement, monitoring and verification program at a hypothetical injection facility.

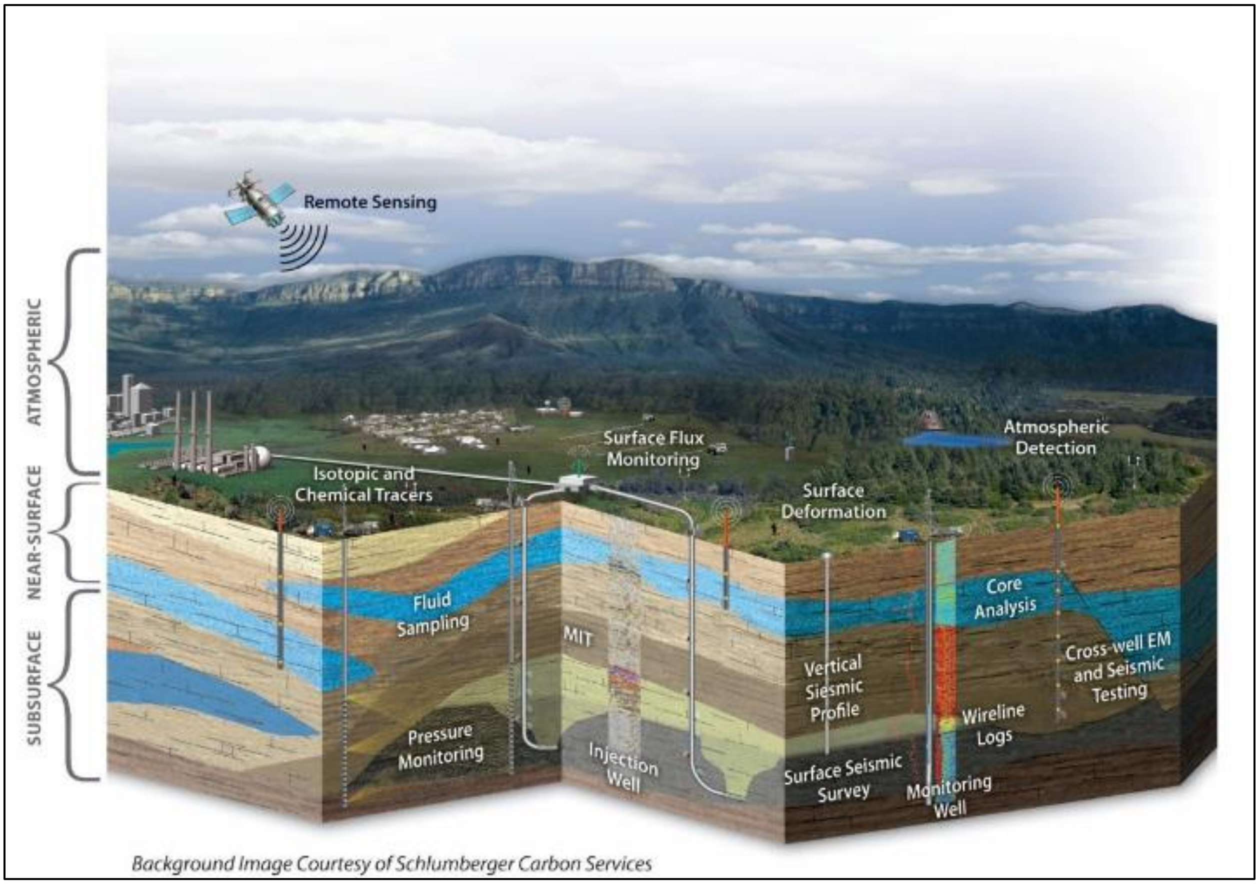


Figure 29: Visual Examples of Monitoring, Verification, Accounting and Assessment
Source: H2-CCS Network [24]

Once the target CO_2 injections have been fulfilled and verified, the post-injection period commences. This stage includes a proper closure process for operations and sealing of the well, as well as ongoing site stewardship. New rules and regulations may be needed in Ontario to define accountabilities for retired injection wells.

Figure 30 shows Illinois Basin-Decatur CCS Project operating adjacent to an ADM corn processing plant. Funded in part through the Midwest Geological Sequestration Consortium by the U.S. Department of Energy – National Energy Technology Laboratory, the goal of this project was to confirm the capacity of the Mt. Simon Sandstone Formation to accept and store 1 megatonne of CO_2 over a three-year period. Surpassing this goal in 2021, the facility is permitted to continue operating with a potential for 5.5 Mt of CO_2 stored. The Illinois State Geological Survey at the University of Illinois designed, implemented, and monitored the project and ADM was the host and operator.

Figure 30: Illinois Basin-Decatur Carbon Capture and Storage Project
Source: pickup12 [25]

2.2.3 Legal framework considerations – Who owns the pore space?

In Ontario, there is no legal framework or interpretation specifically focused on the issue of injecting CO_2 into subsurface geological formations. In Alberta, by contrast, the Mines and Minerals Act of 2010 declares that geological pore space, which is the target of disposal of CO_2, belongs to the Crown except where title is held by Canada. This resolves the uncertainty of whether pore space is assigned as a surface right or a mineral right, or a mix of the two, in Alberta. This uncertainty may exist in Ontario, as the legislation under which CO_2 storage would be governed is presumed to be the Mining Act and the Public Lands Act, wherein mining rights are rights to the minerals in, on and under the surface, while surface rights are all of the rights to the land above *and below* the surface *other than* the mining rights. This means that the two sets of rights in Ontario extend upward and downward indefinitely – how either of these applies to the pore space for CO_2 disposal is thus unclear. It may be that a well-reasoned interpretation of the prevailing law is needed to advance CO_2 storage in Ontario, or possibly new legislation to clarify the matter will be required. Moreover, the *Less Red Tape, Stronger Ontario Act, 2023*, repeals a prior prohibition on the injection of CO_2 underground for the purpose of sequestration, and this brings questions of permitting and stewardship back to the fore in Ontario.

Alberta's Mines and Minerals Act provides for the Carbon Sequestration Tenure Regulation, which authorizes the issuing of permits for evaluating a site for injection and storage, and leases for sequestration. Permits require that a Measurement, Monitoring and Verification (MMV) plan is submitted. The evaluation permit grants rights to conduct testing, including drilling and injections as approved by the Alberta Energy Regulator (AER). Permits expire after five years and are constrained to an area of roughly 70,000 hectares. The MMV plan must address possible interference of CO_2 injection with the recovery of any other minerals, oil or gas resources since inhibiting resource recovery would not be permitted under the law. Note that the AER has no specific directive for CO_2 capture and storage. Instead, the AER treats CCS projects as Acid Gas Disposal, for which rules exist. Acid gases – namely, CO_2 and hydrogen sulphide (H_2S) – are commonly injected back into the ground as a means of disposing the sulphur by-product from refining petroleum products (sulphur is naturally occurring in some oil and gas reservoirs.)

Based on the strength of the evaluation and MMV plan, a sequestration lease may be issued. The lease is valid for 15 years but may be renewed, provided the MMV plan and injection well closure plans are approved by the AER. The closure plan is comprehensive, requiring the documentation of all activities during the lease and the amount of CO_2 injected. All decommissioning or reclamation activities are part of the closure plan, as well as advice from lessee on future MMV plans. This is required because upon issuing a closure certificate, the government assumes ownership rights of the injected CO_2 and, hence, legal obligations under all applicable laws. The lessee is subsequently released from indemnity under the Mines and Minerals Act, as well as third party tort liability. However, climate liability is not transferred from the lessee if any reversal of CO_2 injection should occur. Fees are collected throughout the process for the Post Closure Stewardship Fund, disbursements from which are to cover the Crown's ongoing costs of fulfilling its obligations under regulations as prescribed under the Act.

CO_2 capture and sequestration projects in Alberta may generate offset credits under the province's carbon regulations. The offset rules include conditions on what constitute a legitimate capture of CO_2, including that it must be stored in a formation capable of storing 1 Mt of CO_2 per year. Also, once the price on carbon rises to $80 or higher, capture no longer generates a credit under Alberta regulation, since at that rate offsets are no longer considered needed to incentivize capture and sequestration CO_2.

The experience in Alberta may help inform the development of an enabling framework for CCUS in Ontario. The model in Alberta resolves potential concerns about individual landowners restricting CO_2 injection and sequestration activity, which could be important given the density of populations throughout southern Ontario. However, there are likely to be circumstances unique to Ontario for which new ideas are needed. For example, an injection point offshore in Lake Erie may be considered promising from a geological perspective, but the Great Lakes are under federal jurisdiction because they are Boundary Waters by treaty (i.e., sharing an international border with the U.S.). Some form of joint, intergovernmental resolution may be needed to act on lakebed injection opportunities.

2.2.4 Comment on international cooperation

Regarding international coordination, the geological repositories for CO_2 do not align to any borders, and ideal formations are contiguous throughout southern Ontario and several Midwest States. It would be more efficient for the jurisdictions having common interest in CCUS development to cooperate. A market zone for the exchange of services relating to CO_2 transport, injection and storage could facilitate more efficient and lower-cost exploitation of shared geological resources, while accounting for inter-boundary CO_2 transfers in the respective, national GHG inventories.

An example of multi-jurisdiction collaboration is the Midwest Regional Carbon Sequestration Partnership (MRCSP) [26], representing stakeholders from ten U.S. states: Delaware, Indiana, Kentucky, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, and West Virginia. Members of MRCSP include academic institutions, state geological surveys, and industry. Program objectives include field surveys, CCUS testing, regional mapping, opportunity assessment, and public outreach and engagement. The Government of Ontario could consider approaching the MRCSP with an offer to expand its membership with provincial stakeholders.

Approximately 8,000 tonnes of CO_2 per day is already transported across the U.S.-Canada borde from its source at a coal gasification power plant in North Dakota to Weyburn, Saskatchewan, along a 330 km-long pipeline, where it is injected and stored underground as part of an enhanced oil recovery project [6]. This activity establishes further precedent for cooperation between jurisdictions on both sides of the international border.

2.3 Uses of Captured Carbon – A Brief Discussion on Non-Storage Fates

CO_2 is a required input to numerous production processes, including the carbonation of beverages, as a food additive, as an inert gas and for use as a fire extinguishing agent, and as a refrigerant (i.e., dry ice). Similarly, CO_2 captured for the purpose of mitigating climate change could find some applications that would obviate the need for permanent sequestration. Emerging processes for low-carbon intensity synthetic fuels are one example. Captured CO_2 and hydrogen from electrolysis are the principal feedstocks for Power-to-Liquids fuels production – also called electrofuels or renewable fuels of non-biological origin. Such processes could generate low-carbon gasoline, diesel, or jet fuels. However, this does not permanently remove CO_2 from the atmosphere; it simply cycles the carbon through successive uses as a fuel.

Elemental carbon (i.e., carbon black) produced through methane pyrolysis, for example, is a form of captured carbon that has market application and value, as previously discussed. Most commercially produced carbon black is used in in the manufacture of tires and other flexible rubber goods, such as machine belts and hoses, where it serves as a pigment and to improve durability. It is also used in the production of various inks and paints, as well as printer toner, and its capacity to absorb ultraviolet radiation makes it a stabilizing agent in polypropylene plastics, such as in consumer packaging. It also has good conductivity and confer this property to various plastics and adhesives into which it is mixed.

The market for carbon black in its nanoform, as in carbon nanotubes, is emerging. The anticipated applications include lightweight, high-strength materials, as carbon nanotube structures have been shown to have exceedingly high tensile strength. Novel designs in electronic components, conductors and energy storage materials are also an area of engineering research using nanoform carbon.

Recent research on concrete materials indicates an increase to strength when carbon black is added to the cement. If proven and commercialized, this application could become a ready end-use for large volumes of carbon black as a form of captured carbon.

Carbon that it diverted from entering the atmosphere as a GHG and instead becomes part of a durable product, such as in the elemental, carbon black examples described above, has the same effect as permanent, geological sequestration of CO_2. Yet this utilization of carbon is not currently recognized as a compliance option for industrial emitters under Ontario and federal regulations (only permanent storage is). Addressing this gap in regulatory motivation would support the development of non-storage fates that lock carbon in durable goods for the long-term.

3.0 STORAGE OF HYDROGEN – A REVIEW OF APPLICABLE OPTIONS

Why store hydrogen? The trite answer is, “Because you can!” Oil and gas products represent a portable store of energy that can be accumulated, dispatched, and converted into useful work through combustion when, where and as needed. For example, the storage of natural gas at the Dawn Hub near Sarnia allows the fuel to be accumulated in the warm season, when demand is low, and then drawn down to meet rising demand for heat in the cooler season. This has the effect of stabilizing gas prices throughout the year for consumers. Similarly, the U.S. government recently released crude oil from its strategic petroleum reserve to counter the rising price of distillate fuels (e.g., gasoline, diesel, jet fuel). By contrast, electricity is an energy commodity that cannot simply be captured in a bottle and stored for later use; rather, electrical energy must be used as it is produced. In other words, the production of power must balance perfectly with its consumption. The function of power transmission and distribution grids is to maintain this balance across all generators and users that are connected to the system.

To clarify, electricity storage does, in fact, happen all the time. Batteries are a ubiquitous example. Voltage applied to a battery drives a chemical reaction within, accumulating a store of energy in chemical form. When powering a load (say, a flashlight, cellphone, or electric vehicle), the chemical energy converts to electrical voltage as the battery discharges. However, batteries are expensive to make, and are heavy for the amount of energy they can store, compared to liquid and gaseous fuels. That we rely on batteries and other electrical storage systems notwithstanding, indicates just how much value society places on electricity.

Hydrogen shares characteristics of both fuels and electricity. Like hydrocarbon fuels, hydrogen can be accumulated, stored indefinitely, and moved by any mode of transportation – by road, rail, marine or air. It can also be combusted like a fuel to produce heat, which can be harnessed in an engine for power. However, the hydrogen molecule, H_2, is free of carbon. When combusted, no CO_2 is produced. In this sense, hydrogen is similar to electricity, as no emissions occur at the point of use, other than water. Fuel cells can also generate electricity using hydrogen, directly and without combustion, relying instead on an electrochemical reaction – not unlike a battery. Reversing this sequence, electricity can be applied to water to produce hydrogen. This principle is illustrated in the image below.

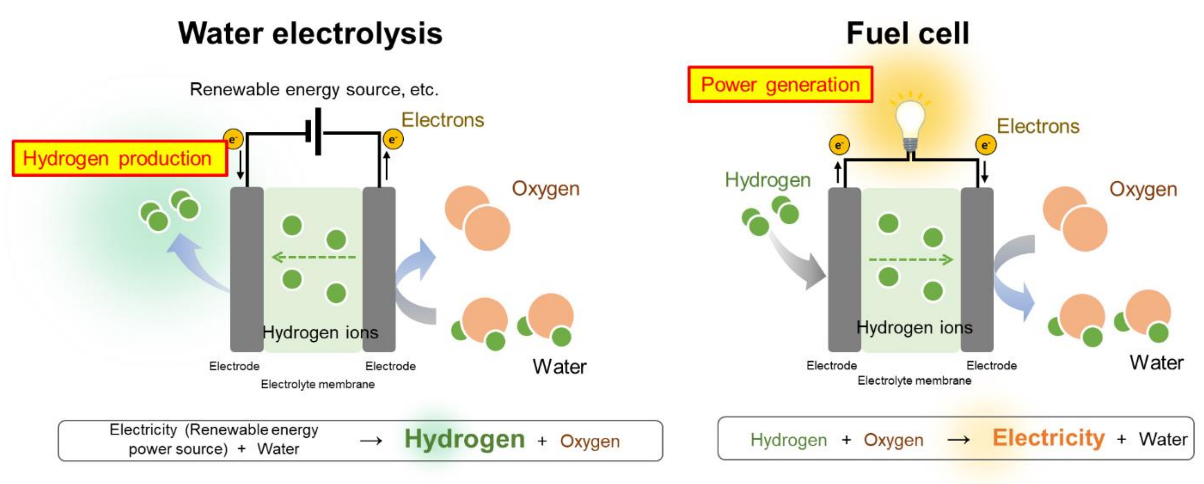


Figure 31: Electrochemical processes in water electrolysis and in fuel cells
Source: All About ... Sustainability [27]

Due to its bidirectional role electrical systems – both as a source of electrical power and as a means of storing electrical energy – hydrogen is often referred to as an electrofuel. Hydrogen can also be an expensive commodity. To keep the cost of production low, opportunistic use of energy that is priced low on the margins can be used, such as off-peak electricity or sources of waste heat. Even so, hydrogen is too expensive to waste. To minimize losses, hydrogen should be stored until its needed. Storage enables a buffer between supply and demand, which can bridge temporal asymmetries in production and consumption over both short-term (e.g., hourly, daily) and long-term durations (e.g., monthly, seasonal).

Notably, the production of hydrogen via electrolysis at sufficient scale can provide valuable services to electricity grid operators. Some types of electrolysis plants can ramp to full, multi-megawatt power draw in a matter of seconds, and then down to zero again. Hence, electrolysis units can be operated as dispatchable loads by the grid system operator, thus enabling a range of grid-stabilizing functions, such as frequency regulation, flexibility ramping, spinning reserve and, of course, grid energy storage. In this sense, the hydrogen produced by the electrolysis is valued by-product of the primary service. In Markham, Ontario, a 2.5-megawatt electrolysis plant was built by a consortium that included Enbridge Gas, to demonstrate the feasibility of commercial grid services provided to Ontario's Independent Electricity System Operator. Located on Enbridge Gas property, the hydrogen gas produced is collected and stored in a standard, ground-mounted storage tank.

Figure 32: Hydrogen Storage Tank
Source: Enbridge Gas [59]

As addressed in the following sections, the storage of hydrogen using ground-mounted tanks and vessels is common practice for handling relatively small amounts, but it can also be stored in certain geological formations in Ontario, offering a solution for managing hydrogen reserves at a seasonal scale.

3.1 Surface Storage of Hydrogen – Equipment and Systems

Systems of hydrogen storage are commercially established and follow similar design characteristics to numerous other gases for industrial purposes, such as nitrogen, oxygen and natural gas. Like these gases, hydrogen is usually stored in a gaseous state under pressure. Several classifications of cylinder tanks are designated for different storage pressures and conditions (e.g., 250 barg, 350 barg, 700 barg). To reach higher pressures more compressor power is needed, and this increases cost. So, the highest pressures are specified only when the available space is at a premium. Like many gases, hydrogen can also be cryogenically liquefied.

Keeping hydrogen in a liquid phase requires minimal pressurization (10 - 15 bar(g)), but it requires intensive insulation to keep the temperature below hydrogen's boiling point (i.e., -253 degrees Celsius). For this, vacuum-insulated tanks called dewars are used. Chilling hydrogen to a liquid state is more energy-intensive than compression, and thus more expensive, but it is currently the most dense and space-efficient form of storage.

Figure 33: Above-ground, LH_2 tank
Source: Hydrogen Fuel Cell Partnership [60]

Compressed hydrogen storage tanks can be built to a wide range of capacities. A hydrogen refuelling station with a public access retail forecourt would generally be provided with hydrogen by on site production of the hydrogen or off-site production of the hydrogen and subsequent delivery to the station via tube trailers. In the case of on-site production, the on site storage volumes are modest, 200 – 300 kilograms to ensure adequate supply during peak hours. In the case of the tube trailer delivery, the volumes are higher, 1,000 – 2,000 kilograms due to the "drop and swap" nature of tube trailer delivery. Similarly, liquid hydrogen (LH_2) storage is usually sized-to-purpose. Typical dewars may hold anywhere from several hundred to several thousand kilograms of LH_2. Currently, NASA is building the world's largest, spherical LH_2 tank at the Kennedy Space Centre, with capacity for more than 300,000 kg (300 tonnes). As a point of reference, a typical fuel cell-electric passenger car will carry around 5 kg of hydrogen on-board, which provides an approximately equivalent range and function as a car having 40-litre gasoline tank.

Figure 34: World's largest liquid hydrogen storage tank under construction
Source: Swanger [61]

Another key difference between compressed hydrogen (GH_2) and LH_2 is permanence. As a compressed gas, hydrogen can be stored indefinitely. By contrast, a cryogenic liquid will boil as it warms over time. This boil-off gas must be allowed to escape to prevent over-pressuring the insulated tank. Typical boil-off rates range from 0.3 to 0.6 per cent per day. So, within a matter of weeks, a store of LH_2 may be completely lost to boil-off. Hence, LH_2 is acceptable for short-term storage, but not long-term. Note that boil-off hydrogen can be captured, but this is costly and inefficient; it is better to put the hydrogen to valuable use before it is lost.

Figure 35: Compressed Hydrogen Tube Trailer
Source: FIBA Canning Inc. [62]

Transporting hydrogen to and from storage facilities is usually performed by on-road truck, although transport by rail and by marine shipping is also feasible. Transport by pipeline is also used when the volume and frequency is sufficient. There are fewer than 5,000 km of dedicated hydrogen pipelines in operation around the world. Most of this is represented in short runs within industrial chemical and petrochemical facilities, but it indicates the potential for networking large volumes of hydrogen production and use. Over long distances, hydrogen would likely move as a gas under pressure maintained by booster compressor stations. Storage, transport and compressor equipment, as well as valves, hoses and other accessories, must all be specifically designed to handle hydrogen – equipment made for other commodities, such as natural gas, may not be repurposed for hydrogen. The issue is that H_2 can react with many metals and weld materials, and it can pass through tight spaces that larger molecules would not, and thus leak to atmosphere. However, pipelines can be designed to carry both natural gas and hydrogen. Current natural gas pipelines are capable of carrying modest levels of hydrogen blended into the stream. The U.S. Department of Energy is exploring the use of fiber-reinforced polymer as a dedicated hydrogen pipeline material, which could cost significantly less than steel pipeline construction as far fewer section welds are required [28]. Conceivably, a program of converting existing natural gas pipelines to accommodate hydrogen could provide a low-carbon pathway for heat and power.

Large-volume hydrogen production, storage and distribution is common practice in industrial refinery and chemicals facilities and is subject to established codes and rules. For facilities smaller than these industrial-scale operations, the Canadian Hydrogen Installation Code applies (i.e., CAN/BNQ-1784-000). It defines the requirements for equipment used in generating, utilization, dispensing, storing, and piping hydrogen. Furthermore, hydrogen can be used indoors. For example, in warehouses and distribution centres across North America, there are some 20,000 fuel cell-electric forklifts operating, with dispensing and refueling occurring inside the building. Hydrogen is not toxic, but it is flammable in an oxygen environment (as are most fuels). The way to render hydrogen safe is to let it vent to atmosphere, where it disperses quickly. This eliminates the hazard of fire or explosion. Thus, the safest place to store hydrogen is outdoors.

3.2 Subsurface Hydrogen Storage (Geological Storage)

To the extent of the study team’s research, there are five locations worldwide that currently store pure hydrogen underground in geological formations; that is, not in fabricated storage tanks. Four are examples of storing hydrogen in salt cavern (three of these locations are in the U.S.), and one is an example of storage in a hard rock cavern (a new pilot-scale facility in Sweden). However, there are examples of gas mixtures containing H_2, such as town gas –

composed of roughly equal amounts of carbon monoxide and hydrogen – stored in other formations, such as aquifers. Four geological storage options are briefly discussed herein, as relevant to an Ontario context: salt caverns, depleted oil and gas reservoirs, saline aquifers and hard rock caverns.

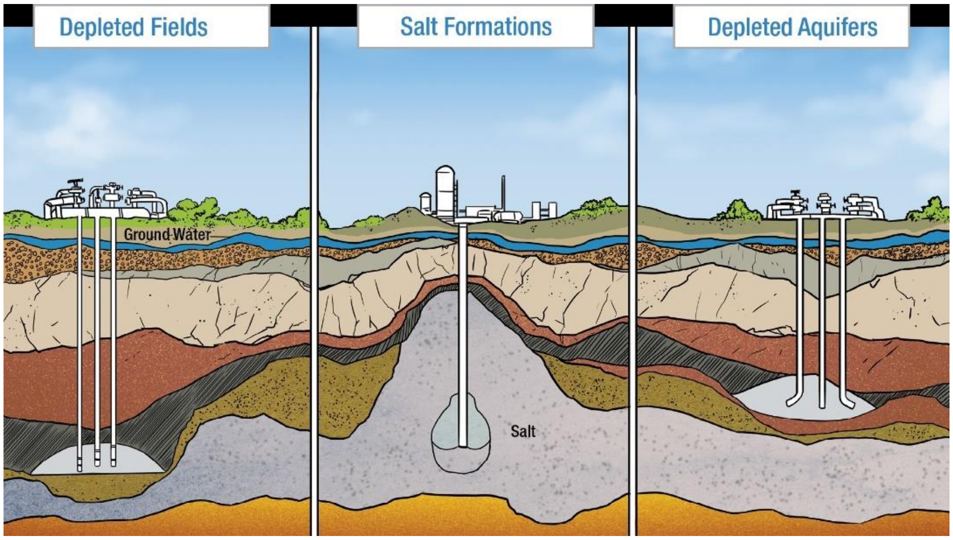


Figure 36: Visual Examples of Underground Gas Storage
Source: Dana Energy [29]

3.2.1 Salt Caverns

Subsurface salt formations exist throughout parts of southern Ontario. These geological formations can be solution-mined from the surface to create large caverns with attractive properties for compressed gas storage. Indeed, some post-producing solution mines are currently used for natural gas storage. There are some 20 solution mining operations active in Ontario, as well as many inactive sites. Solution mining involves drilling into the salt formation and injecting fresh water. The salt is water-soluble, producing a brine that is extracted to the surface. The process leaves behind a void in the salt formation that can serve as a storage reservoir for gas and liquids.

Salt caverns have several ideal characteristics for hydrogen storage. The crystalline structures comprising the cavern surface is highly impermeable to gases, including hydrogen. The geomechanics of the salt provide a degree of plasticity, meaning that some deformation can occur within the structure under pressure without compromising integrity of containment. The salt also inhibits biological activity, so stored hydrogen will not undergo metabolism by microbes, which could otherwise contaminate the gas.

The suitability of a salt deposit for hydrogen storage depends on a number of factors. It must exist at the proper depth. Deeper caverns will withstand greater pressurizing of the stored gas without fracturing, due to the weight of the rock above. Depths of at least 300-400m would be preferable. The thickness of the formation is also important, as is its homogeneity, so that sizeable caverns can be leached. The presence of insoluble impurities in the salt or from other sedimentary formations (e.g., interbeds of limestones or shale) must be avoided.

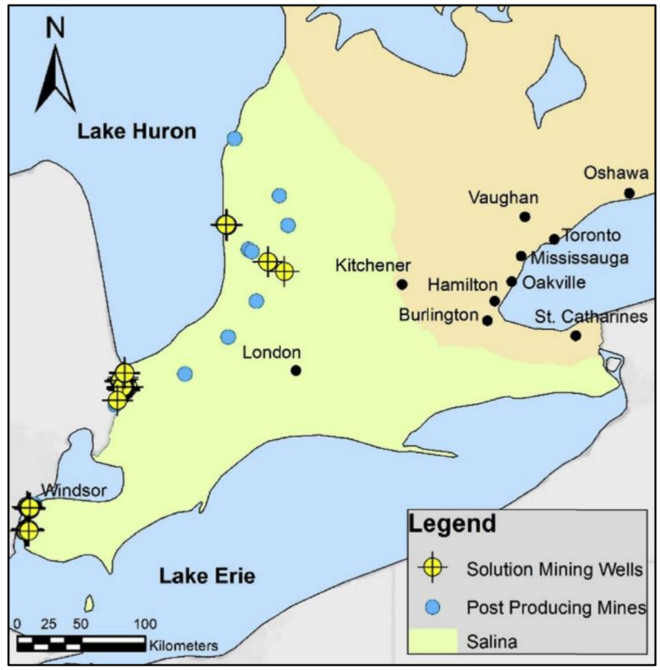


Figure 37: Locations of past and present solution mining wells relative to the spatial extent of the Salina formation

Source: Lemieux *et al.* [52]

Solution mining in Ontario currently targets layers of bedded rock salt within the Salina Formation. This formation occurs at depths of 275-800m below the surface in southern Ontario. Specially, within the Salina Formation are two distinct layers, or units – the B-Salt and A-2 Evaporite units – that are most promising for subsurface hydrogen storage. From the surface, the B-Salt unit covers a large area (approximately 16,000 km^2) and has an average thickness of 90m at depths of about 400m. Solution mining in in the B-Salt unit occurs in Goderich and Windsor, and there is active cavern storage in Sarnia and in Windsor. The A-2 unit has an estimated thickness of up to 45m and depths ranging from 500-825m. Underground mining (i.e., not solution mining) in the A-2 unit occurs in Goderich and there is existing cavern storage in Sarnia. The map below shows where the B-Salt and A-2 Evaporite units are located from the perspective of a surface operation.

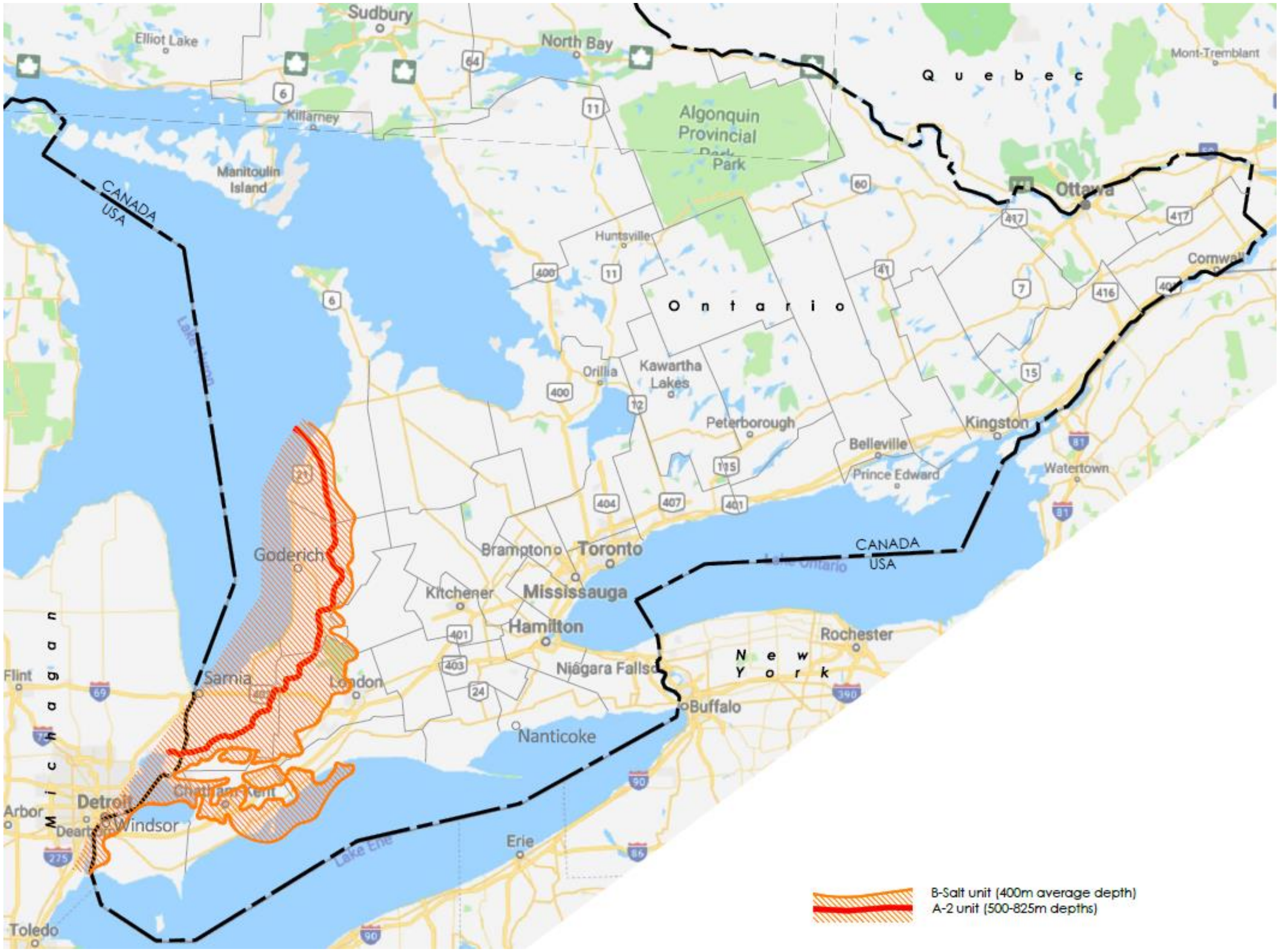


Figure 38: Areas of potential salt cavern sites within the Salina Formation
Source: Adapted from Carter [30]

The layers within the Salina formation offer the most promising salt deposit candidates for purpose-built, solution-mined caverns that could be used for subsurface storage of hydrogen gas under pressure. Storage pressures are expected to range from a maximum of 80 per cent of the static pressure within the formation (a function of depth), down to a minimum of 30 per cent [31]. Lemieux A et al estimates that a hypothetical salt cavern having a geometric storage volume of 210,000 m^3 (similar to an actual facility in the U.K.) could contain 6.4 million m^3 of hydrogen gas at 400m depth (i.e., in the B-Salt unit) and 9.5 million m^3 at 525m (i.e., in the A-2 unit). Very roughly, this represents 500 and 800 tonnes of stored hydrogen, respectively, which is comparable to roughly 2 to 3 million litres of diesel in terms of energy content, and the pressure at these depths is estimated at about 40 to 50 bar. Note that to keep pressure above a minimum level, some hydrogen gas must always be left in the cavern. Referred to as the cushion gas, its commercial value is part of the sunk cost of the operation, and it can represent 30 to 50 per cent of the maximum stored hydrogen. Another option is to use a liquid, such as saturated brine, which is injected and withdrawn as needed to maintain a constant pressure within the hydrogen stored.

Due to residual moisture in salt caverns created by solution mining, hydrogen may need to be dehydrated upon withdrawal from storage. Driers are a common piece of equipment, but it adds to the operational costs.

The salt deposits in southern Ontario are part of the Michigan and Appalachian sedimentary basins. The sedimentary basins in Ontario's north – the Hudson Bay and Moose River basins – also have formations with salt deposits. The study team speculates that these formations could have potential for large-volume, subsurface hydrogen storage, but confirmation is beyond the scope of this report.

Injection wells used for solution mining are designated Class III by the U.S. EPA. As with CO_2 injection, any solution well must be permitted, monitored and, upon conclusion of operations, properly sealed. Leaks and changes to the local geology must be sensed, analyzed and reported, as well as the integrity of the well equipment and casing.

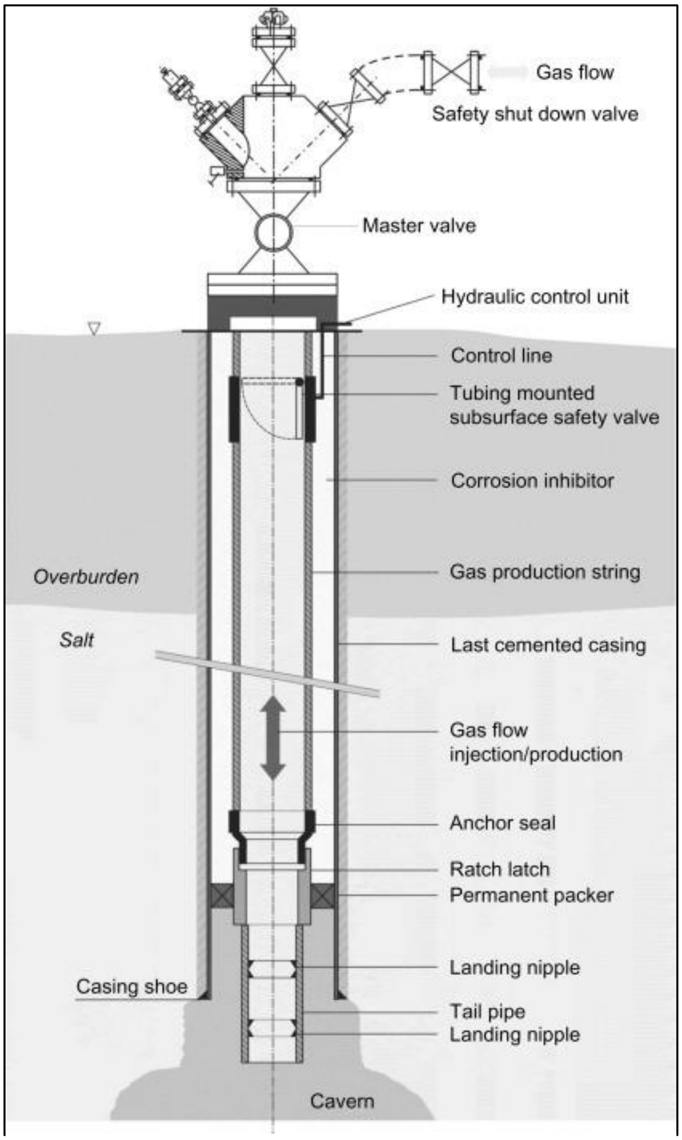


Figure 39: Solution Mining Injection Well
Source: Barbir *et al.* [64]

3.2.2 Depleted Oil and Gas Reservoirs

In the discussion on CO_2 storage previously in this report, depleted oil and gas reservoirs were characterized as having potential for permanent sequestration. Reef structures, in which uplifts occurring with Silurian carbonate formations are already used for natural gas storage within the Dawn Hub (see Figure 23). These pinnacles serve as traps for oil and gas, where overlain formations of limestone, salt or dolostone from a caprock. These types of formations might also be used for hydrogen storage. Other reef structures exist throughout southern Ontario may also have potential for hydrogen storage, but this requires further survey and analysis to confirm (Figure 39 indicates where prospective reefs exist).

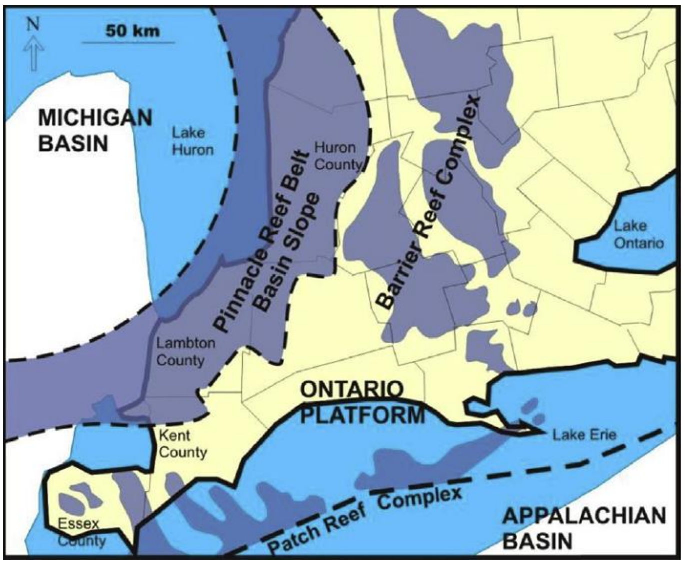


Figure 40: Reef Belts in Ontario
Source: Lemieux *et al.* [52]

Generally, any geological formation that is effectively trapping pools of oil and gas is potential prospect for hydrogen storage, too. However, hydrocarbon environments can sometimes support microbial life (i.e., bacterial, and archaeal) that could metabolize hydrogen stored in the reservoir, representing a loss of hydrogen and a source of contamination within the gas. Other challenges facing the storage of CO_2 in depleted oil and gas reservoirs, such as the prevalence of abandoned and unsealed wellbores in the formation, also apply to the prospects of hydrogen storage. Even where a pool of oil and gas exists, it is not necessarily proof that no leakage is happening. There could be slow migration of gas upward from the deposit through the overlain formations, notwithstanding the accumulation of hydrocarbon in the trap. Hydrogen could thus permeate out of the trap more rapidly, especially under high storage pressures.

3.2.3 Saline Aquifers

The geology that makes deep saline aquifers promising formations into which CO_2 can be injected for storage also makes them a prospect for hydrogen storage. The porous sandstone of the Mount Simon Formation provides the volume for hydrogen storage, and the overlying caprock provides a potential seal. The depths would also enable storage at high pressures, making efficient use of the pore space and facilitating withdrawal of stored hydrogen. Conceptually, hydrogen storage could be stored at shallower depths than that needed to sequester CO_2 (i.e., >800m). This would also make more of the formation accessible from the surface in Ontario. Because hydrogen injected into the aquifer would remain a gas with high buoyancy in the saline, locations with anticline caprock[1] would be needed to collect the hydrogen in fixed locations (such as in the reef structures described above). Otherwise, the gas could be lost as it travels along inclines away from the injection point.

[1] An anticline is an arch-like shape in the geological strata, in which older beds are towards the core of the arch, making possible the trapping of buoyant fluid.

3.2.4 Hard Rock Caverns

Whereas sedimentary basins with hydrogen storage potential exist only in the southern and northern portions of Ontario, the Canadian Shield dominates the bulk of the surface area in the province. The Shield is composed of Precambrian crystalline bedrock (i.e., igneous, and metamorphic), most of which is seismically stable. The Shield is actively mined as a rich source of valuable minerals, including nickel, gold, silver, and copper. Parts of the Precambrian have also been extensively studied for potential storage of nuclear waste materials in deep geological repositories. In the context of hydrogen storage, traditional excavation of the rock would create the storage volume. Very high storage pressures could be achieved, and there may be little need for a cushioning fluid or gas, given the strength and stability of the formation. However, minerals in the rock could be reactive with H_2 gas, and there is potential for infiltration of gases and water. Even though some formations in the Shield have very low porosity, there remains a risk of interactions with radionuclides comprising the cavern walls.

To address these concerns, it has been speculated that hard rock caverns could be lined with concrete and steel alloy or polypropylene plastic (chosen to be impermeable and unreactive with H_2) [32]. The concrete would carry the pressure loading, transferring the stress to the surrounding rock, while the steel would only need to withstand some modest deforming stresses. This solution approaches that of a vast, engineered surface storage vessel; nonetheless, it may be economically favourable in certain situations where capacity is paramount and surface footprint is restricted. For example, receiving large hydrogen imports to the province across the Canadian Shield – say, from Manitoba or Quebec – in bulk may require substantial storage waypoints en route to markets in the populated south of Ontario.

3.3 Prospective Hydrogen Storage Siting Opportunities in Ontario

3.3.1 Subsurface Storage for Longer-Term, Seasonal Service

Unlike CO_2 sequestration, where the imperative to reduce GHG emissions drives the urgency of developing potential sites for injection and storage, hydrogen storage capacity within the province can develop according to market demand, which may arise quickly or slowly. In a companion study of H2GO Canada's Ontario Hydrogen Foundation series, *Estimating Low-Carbon Hydrogen Supply and Demand in Ontario to 2050, Based on an Assessment of Effective Value Chain Development*, a reference case scenario projects a significant divergence between supply and demand by 2030. Until then, hydrogen production capacity within the province is estimated to exceed end-use demand in each of the market regions assessed. Under this scenario, the likely need for storage would be to accumulate and buffer hydrogen produced in the province for later use or for export to neighbouring jurisdictions. As demand begins to scale up and surpass regional production potential, these storage resources should be re-purposed for hydrogen imports.

For the purpose of extending this hypothetical analysis, it is assumed that cross-border transport of hydrogen would occur by pipeline, although on-road truck and railway are technically feasible modes until pipeline-scale volumes of exchange are achieved. As a matter of economics, it is further assumed that pipeline export and import of hydrogen would occur along existing rights-of-way (i.e., current pipeline corridors). Where new pipeline routes are required for CO_2 transport from large emitting facilities to injection sites, hydrogen pipelines could run in parallel. Indeed, hydrogen produced from methane, using SMR or ATR processes for example, generates CO_2 that can and should be captured and delivered to injection sites for storage.

Maps presented in the following section of this report include some hypothetical siting of subsurface hydrogen storage. Within the next 10-15 years, it is conceivable that solution-mined salt caverns could be developed along the perimeter of Lake Huron in an arc from Sarnia to Kincardine. Ideally, these caverns would be sited near major pipeline corridors to mobilize stored hydrogen, or near sites of low-carbon power generation or high-voltage transmission nodes as electrical energy input to water electrolysis. Depleted oil reservoirs near Sarnia and Nanticoke may similarly be developed for hydrogen storage potential, as well as mined-out hard rock caverns near North Bay or Sudbury, Sault Ste Marie, and Kingston/Cornwall. Deep saline aquifers are not considered here, based on the assumption that these would be prioritized for CO_2 injection and storage.

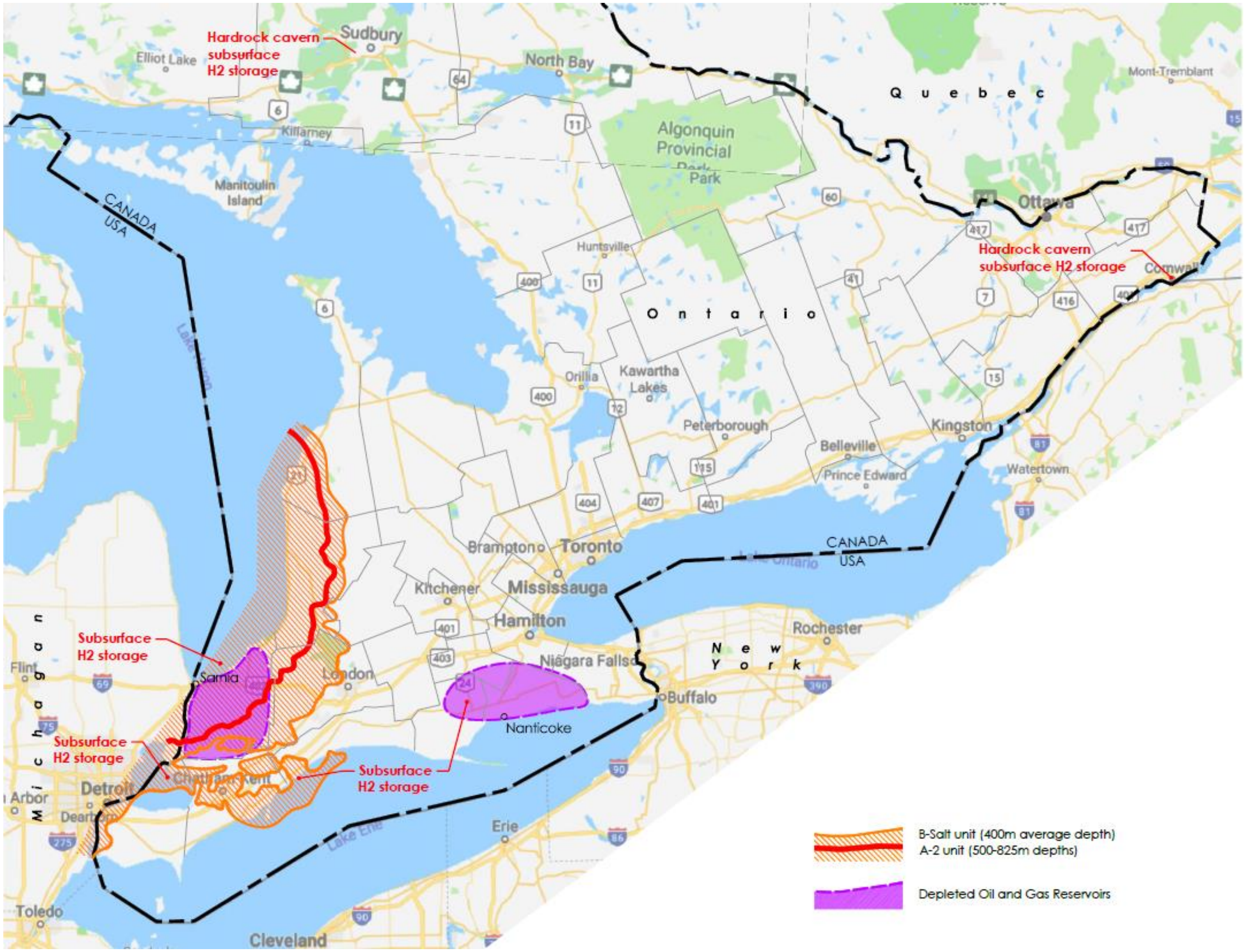


Figure 41: Prospective Areas Having H_2 Subsurface Reservoir Potential

Guidance on costs of subsurface hydrogen storage is offered in a report by Lord *et al.* [33]. The report showcases the use of a model developed at Sandia National Laboratories, called The Hydrogen Geological Storage Model (H2GSM), which assess the major cost components of a large-scale hydrogen facility. The major costs include geologic site preparation (e.g., site assessment, drilling and mining), compressor equipment and operating expenses, cushion gas, pipelines and wells, and a factor for capital recovery. The table below summarizes the site characteristics used in the model (which are based on actual sites in Texas and New Mexico), as well as the output sums by major cost type, for each of four types of geological storage option. The levelized costs of capital and of hydrogen are also relayed from the report, based on a site lifetime of 30 years.

Table A: Cost elements adapted from Lord et al, “Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands”, 2014.

Site characteristic	Salt cavern	Depleted oil & gas reservoir	Hard rock cavern	Aquifer
Void volume, m^3	580,000	676,941	580,000	676,941
Well depth, m	1,158	1,403	1,158	1,403
Working gas, t	1,912			
Cushion gas, t	574	956	574	956
% cushion of total	30	50	30	50
Total H_2 stored, t	2,486	2,868	2,486	2,868
Major capital cost elements (assumptions) in US$				
Site preparation, development	$23,340,000	n/a	$48,720,000	n/a
Compressor	$27,539,480	$18,359,654	$27,539,480	$18,359,654
Pipelines, wells	*$4.39/t*	*$6.26/t*	*$4.39/t*	*$6.26/t*
	$1,147,527	$255,006	$2,157,000	$1,147,526
Cushion gas	$6/kg			
	$11,227,540	$21,492,278	$11,227,540	$21,492,278
Total capital costs	$63,254,547	$40,106,938	$89,644,020	$40,999,458
Levelized capital cost per kg-H_2	**$1.54**	**$1.19**	**$2.18**	**$1.21**
Levelized cost of H_2/kg including O&M	**$1.61**	**$1.23**	**$2.77**	**$1.29**

Source: Lord *et al.* [32]

The total hydrogen storage requirement (i.e., the working gas) was estimated based of the City of Houston’s population of 3,823,000 people. The assumption was 10 per cent of transportation energy demand was fulfilled by hydrogen (i.e., a 10 per cent market penetration). An average daily demand was calculated, and then a 10 per cent “summer surge” over that average, lasting 120 days, was calculated. This yielded the volume needed for storage. One salt cavern is sufficient at 10 per cent market penetration to serve the Houston population, but at 100 per cent four caverns of larger volume are needed. It was noted that in Pittsburgh, which has a lower population, more salt caverns are needed because the salt formations thinner in the geologic stratigraphy compared to the deeper, more ideal salt formations in the Houston area.

3.3.2 Surface Storage for Shorter-Term Service

Surface storage capacity will likely be highly distributed within localized areas of hydrogen production and use. Modest amounts of ground storage are a common feature of most hydrogen installations. However, some larger ground-based storage may have value in certain situations. For example, a site having large low-carbon, low-cost power generation capacity, such as a nuclear plant, wind farm or run-of-the-river hydro plant, may divert some of its capacity to an adjacent electrolysis facility to produce hydrogen. This may be spare capacity that cannot be fed into the gird during regular periods of low electricity demand. The volume of hydrogen produced may require only a few days of storage, whereupon trucks hauling tube trailers could take scheduled loads of hydrogen to markets near-by – say, within 100 km distance. Sizeable surface storage facilities would thus be located near generating stations or nodes along the transmission grid.

3.4 Legal Framework Considerations

Unlike the legal framework considerations for CO_2 discussed in the previous section, hydrogen storage is not expected to have the same legal complexities. Hydrogen is not being permanently sequestered; rather, the mining activity (i.e. in salt deposits or in hard rock formations) is to facilitate temporary storage, similar to how natural gas storage is currently managed in Ontario. Hydrogen is too valuable a commodity to leave underground. Thus, the regulatory framework that applies to gas and oil storage is expected to apply to hydrogen, as well. The risk assessment will be different, naturally, as the hazards associated with pressurized, subsurface hydrogen storage are different that with petrochemicals, as are the risk mitigations.

Note that hydrogen leaks are not a direct environmental hazard, as is the case with many other fuels and reactive chemicals. The H_2 molecule is not toxic and is rendered safe by allowing the gas to escape to atmosphere. However, hydrogen is flammable when mixed with oxygen (it would have no value as a fuel if it were not combustible). If an uncontrolled leak of hydrogen is trapped and pools with air – say, under a roof or enclosure – then a spark can cause ignition. Therefore, strict standards apply to buildings and enclosures within which hydrogen is used, requiring pathways to atmosphere, hydrogen detectors and active ventilation systems that leaks of gas do not accumulate.

Engagement and consultation with Indigenous communities would be required regarding the scoping and siting of hydrogen storage systems, and co-developments (or Indigenous-led developments) are advisable wherever possible and appropriate.

4.0 MAPPING CURRENT INFRASTRUCTURE IN ONTARIO

This section presents a series of maps that show the current elements of infrastructure that are expected to influence the placement of systems of CCUS and of hydrogen production, subsurface storage, distribution and use, as well as distinct regions of economic activity and population.

These base maps were constructed by the engineering drawing team at Change Energy Services. Resolution was locked at a lower level for incorporation into this report. Master files (Portable Document Format, .pdf) are available that maintain resolution and clarity at all magnifications and allow specific layers to be turned on and off to facilitate scenario analysis. Please contact the report authors to discuss any special requirements for maps and analysis.

4.1 Transportation Corridors by Surface Mode

Shown in Figure 42 is the highway system in Ontario, the network of railways, marine ports and international airports.

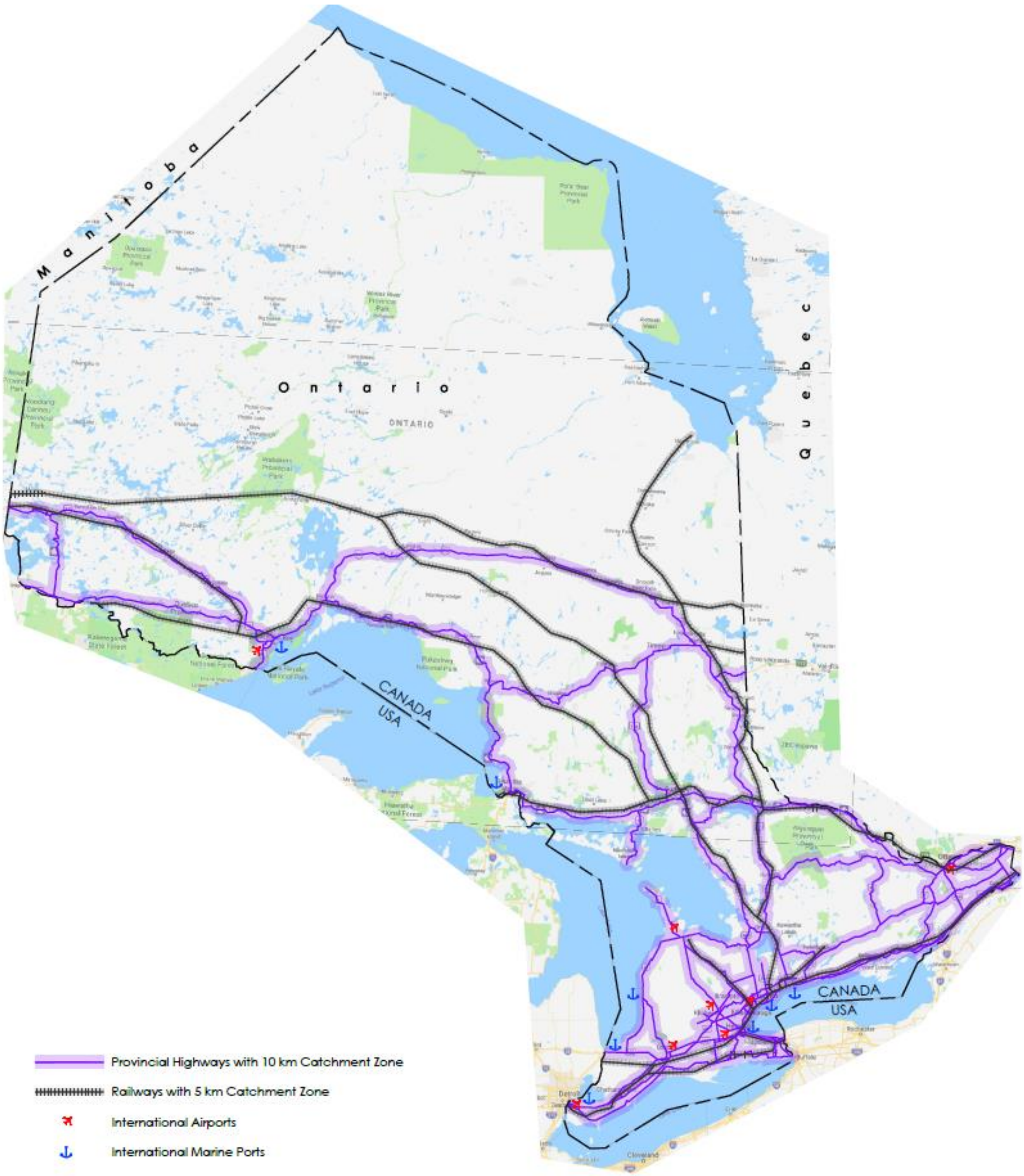


Figure 42: Transportation Corridors
Source: Adapted from Government of Ontario [34], Railway Association of Canada [35]

It may be practical in some instances to transport CO_2 by rail using special tank cars that maintain the cargo in a supercritical fluid state. A 5 km area on either side of the track is shaded, indicating a potential catchment zone for any CO_2 emitters to be efficiently serviced by the railway, representing a short shunting distance to wayside facilities or sideline queues where tank cars could be marshaled. Moving CO_2 long-distance over the road using the highway system is not considered economically practical. Pipeline would be the most practical mode, and this is addressed later in the energy corridor map.

Hydrogen could be transported by rail over long distances, likely in a cryogenic liquefied state, or by highway for shorter distances (e.g., less than 100 km) as a compressed gas. Highways are shown with a 10 km area shaded on either side of the road. Producers (or users) of hydrogen within the catchment zone could use county roads and town streets to move hydrogen tube trailers hauled by Class 6-8 tractors onto (and off of) the highway system.

Marine ports could be used in the export of bulk CO_2 from Ontario for storage elsewhere – perhaps off the Atlantic coast, for example. Ports could also facilitate the import and export of hydrogen by sea. When shipped in bulk carriers, the hydrogen is expected to be carried in molecular bond with other elements, perhaps as ammonia (NH_3) or methanol (CH_3OH), which are liquid at normal temperature and pressure. Indeed, these commodities may have more value than would hydrogen at some ports around the world, especially if low-carbon intensity is valued in those markets and the feedstock hydrogen was made in Ontario using a low-carbon intensive process. More exotic chemicals are also being considered as hydrogen carriers, where good reversibility of reactions enable hydrogen to be added and extracted with ease. For some marine vessels, hydrogen may also be an effective propulsion fuel on the Great Lakes, as traffic there is subject to International Maritime Organization targets for emissions of criteria air contaminants and GHGs.

Locations of international airports in Ontario are also displayed on the map. Hydrogen is increasingly viewed as part of the decarbonization of aviation. Hydrogen has been demonstrated as a fuel in some small-body aircraft that could be used for regional routes. Hydrogen with low carbon-intensity (made from, say, low-carbon power or biogenic waste sources) can be a feedstock for the production of sustainable aviation fuel, which is a synthetic jet fuel. Thus, airports can be destinations for hydrogen and sites of production. International airports are often hubs of local economic activity – much of which involves logistical services – wherein hydrogen production and use could acquire early traction as commercial markets with numerous offtake opportunities.

4.2 Energy Corridors and Power Generating Sites

Shown in Figure 43 are the high-voltage transmission lines (i.e., 230 kVA and up) in Ontario and the connected power generating stations and sites having installed capacity of 20 MW or more, the major transformer stations (not easily visible at the scale shown) and the natural gas transmission pipelines. Power generation sites are differentiated by energy feedstock or powerplant characteristic; that is, nuclear, natural gas-fired, hydroelectric, wind farm, solar farm, and biofuel- or biomass-fired. On either side of the transmission lines and pipelines are shaded catchment zones, representing 50 km and 10 km distances, respectively. Within this area, it is assumed that any CCUS or hydrogen production facility siting can be serviced by the existing infrastructure through new or existing feeder or distribution lines.

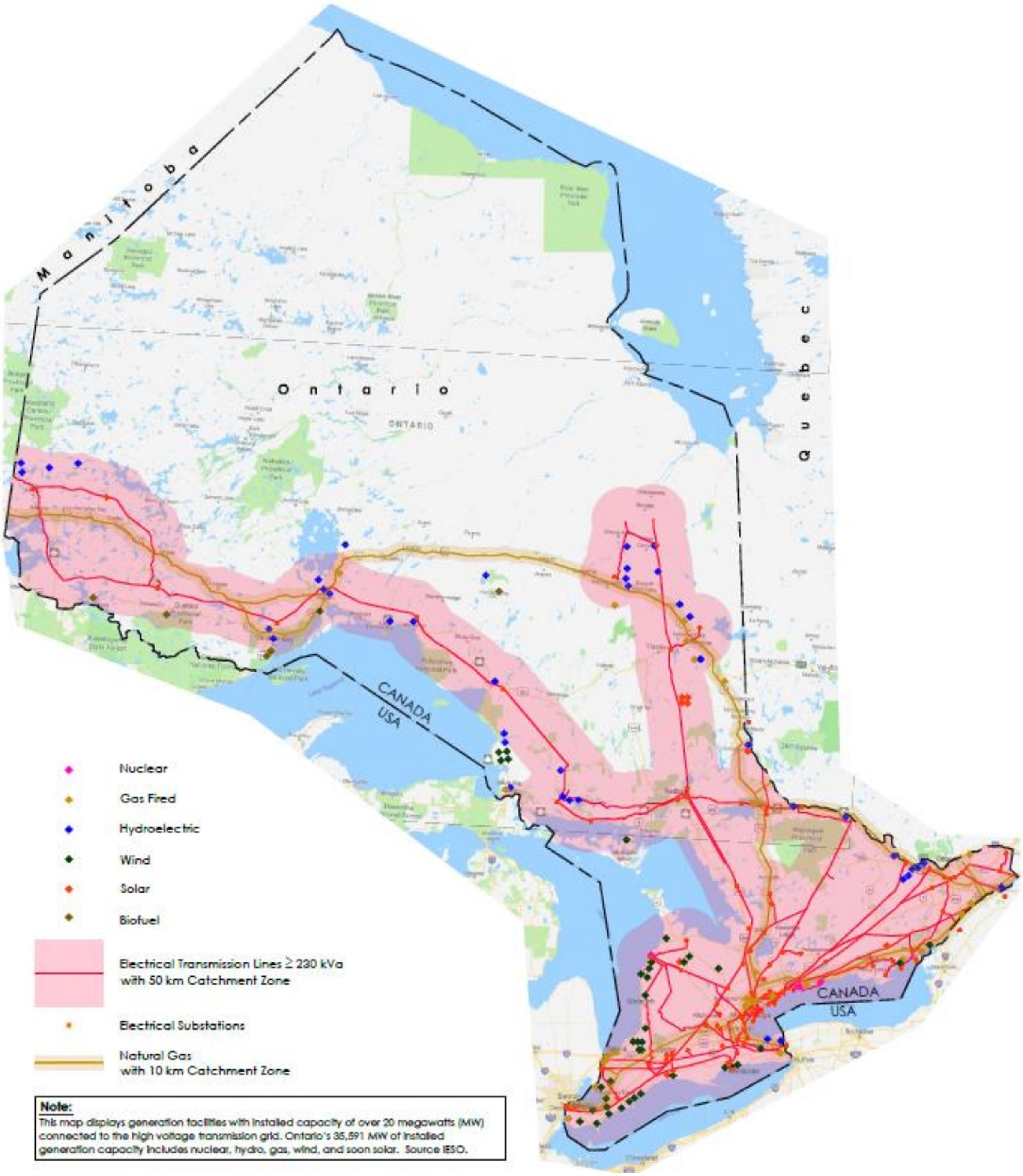


Figure 43: Energy Corridors
Source: Adapted from IESO [36]

As shown, Ontario's south has robust accessibility to the electrical transmission system, making hydrogen production via electrolysis much less constrained that in northern parts.

4.3 Administrative Regions

Both for this report and for the companion report (i.e., *Estimating Low-Carbon Hydrogen Supply and Demand in Ontario to 2050, Based on an Assessment of Effective Value Chain Development*, by H2GO Canada) the provincial territory was parsed into smaller administrative regions to facilitate analysis and modeling of potential hydrogen markets, labeled West, Central West, Central East, North and Far North. These administrative regions were selectively bounded to capture reasonable population sizes for analysis.

The identified regions have distinct industrial characteristics and access to energy resources. These distinctions are not central to the study presented in this report but are an important part of the modeling work conducted for the companion study, as the available levels of power and energy for hydrogen production are estimated.

This report draws on the modeling work conducted for the above noted companion report to inform the geographic placement of potential hydrogen markets, shown later in section 6.3. Note that the data in these tables, which are linked to the companion study, are subject to changes made in the companion report, but the impact on the mapping analysis in this study would be negligible.

Below is the population projection for each of the administrative regions shown in the map, as well as the distribution of generating assets and output.

Figure 44: Administrative Region Boundaries
Source: Adapted from Government of Ontario [37]

Table B: Regional Population

Region	Population			
	2020	2025	2030	2035
Far North	150,978	150,699	150,057	149,645
North	660,412	672,815	677,022	680,316
North(s)	811,390	823,514	827,079	829,961
West	4,518,922	4,876,608	5,194,015	5,510,177
Central West	3,370,442	3,678,305	3,991,569	4,297,432
Central East	3,699,834	3,982,798	4,239,953	4,472,898
East	2,333,426	2,494,729	2,638,036	2,775,440
South	13,922,624	15,032,440	16,063,573	17,055,947
TOTAL North(s) + South	**14,734,014**	**15,855,954**	**16,890,652**	**17,885,908**

Source: Government of Ontario [38]

NOTES:

1. *Population increase forecast: 3,151,894 / 21.4%.*
2. *Regional population distribution in 2020: 5.5% North / 94.5% South.*
3. *Regional population distribution in 2035: 4.6% North / 95.4% South.*

Table C: Regional Electricity Resources

Region	Nuclear			Hydro			Wind			Solar			Biofuel			Gas-fired		
	Qty	Power MW	Energy [3] MWH / yr	Qty	Power MW	Energy [3] MWH / yr	Qty	Power MW	Energy [4] MWH / yr	Qty	Power MW	Energy [4] MWH / yr	Qty	Power MW	Energy [3] MWH / yr	Qty	Power MW	Energy [3] MWH / yr
Far North				14	1,746	12,388,918										3	121	717,247
North				18	1,404	9,962,222	6	431	1,020,158	2	70	137,970	6	344	1,898,467	2	150	886,950
North* (2)				32	3,150	22,351,140	6	431	1,020,158	2	70	137,970	6	344	1,898,467	5	271	1,604,197
West	1	6,550	49,058,190	2	2,308	16,376,645	30	3,277	7,751,612	5	414	815,994				11	4,121	24,367,473
Central West							1	91	216,179							3	1,389	8,213,157
Central East	2	6,624	49,612,435													2	612	3,618,756
East				6	1,979	14,042,192	2	273	645,700							6	3,378	19,974,114
South* (1)	3	13,174	98,670,625	8	4,287	30,418,837	33	3,642	8,613,491	5	414	815,994				22	9,500	56,173,500
Ontario	3	13,174	98,670,625	40	7,437	52,769,977	39	4,073	9,633,649	7	484	953,964	6	344	1,898,467	27	9,771	57,777,697

Notes:

(1) South = W + CW + CE + E
(2) North = N + FN
(3) Energy MWh = energy potential based on 90% "up time"
(4) Energy MWh = energy potential based on 90% "up time" and 30% utilization factor
(5) Production Facilities: 119
(6) Power (MW): 32,596
(7) Energy (MWh/yr): 204,858,000

Table C: Regional Electricity Resources is to be updated as research advances.

Table D: Regional Natural Gas System Operators

Region	Transmission	Distribution
Far North	Trans Canada	Enbridge
North	Trans Canada	Enbridge
West	Trans Canada, Enbridge	Enbridge, Epcor
Central West	Trans Canada	Enbridge
Central East	Trans Canada	Enbridge
East	Trans Canada	Enbridge

4.4 First Nations Lands and Protected Areas
Ontario Opportunity: Hydrogen energy independence in remote and indigenous communities

Included in this report is a reference to a map of First Nations communities, Tribal Councils, Treaties, and Political Organizations, published by the Governments of Canada and of Ontario. An interactive map of Métis Nations of Ontario Community Councils is available at [39]. The study team believes that hydrogen systems may have an important role to play in advancing energy prosperity and economic growth among Indigenous Communities. This is simply a recognition of the fact that Indigenous peoples inhabit communities in all part of Ontario. Some of these communities are disconnected from major energy infrastructure or only partly connected. Others are adjacent to roads, railways and pipelines, and are thus able to transact in energy commodities. In many cases, the communities are reliant on diesel to generate power.

Connecting communities to transmission grids may be cost-prohibitive in some cases, especially for those considered “remote.” Yet many such communities have local energy resources that are renewable, and that could be tapped to generate power, heat and vehicle fuel – hydrogen systems can help to unlock these potentials.

In grid-isolated communities, renewable power generation is often limited to the what the community can use directly. But hydrogen production allows a community to *over*-generate power; whatever power is not used directly can be stored as hydrogen for later use in the community, or for trade. If one community has a surplus of hydrogen and another community is in need, the hydrogen can be moved between the two, possibly by truck (where roads exist), by pipeline or even by small aircraft. Conceivably, hydrogen could become a transacted commodity around which a clean energy network develops for remote and connected communities.

As a matter of law and of Reconciliation, development of CCUS or hydrogen storage systems in Ontario must follow consultative engagement with the prescribed communities under Treaty. H2GO Canada seeks to consult further with Indigenous-led organizations to better reflect their understanding and perspectives in these maps.

For further reference, Appendix 2 includes a list of all First Nations with territories in Ontario, Métis Nations of Ontario and a list of current Indigenous energy projects and facilities [40].

Figure 45: First Nations Communities, Tribal Councils, Treaties, and Political Organizations
Source: © King's Printer for Ontario, 2011. Reproduced with permission. [41]

The location of administrative centres for First Nations lands are represented in H2GO Canada base mapping data, as show in Figure 46, below. Métis Nation of Ontario Community Councils have offices in many cities and towns. A full list of all administrative offices can be found in Appendix 1.

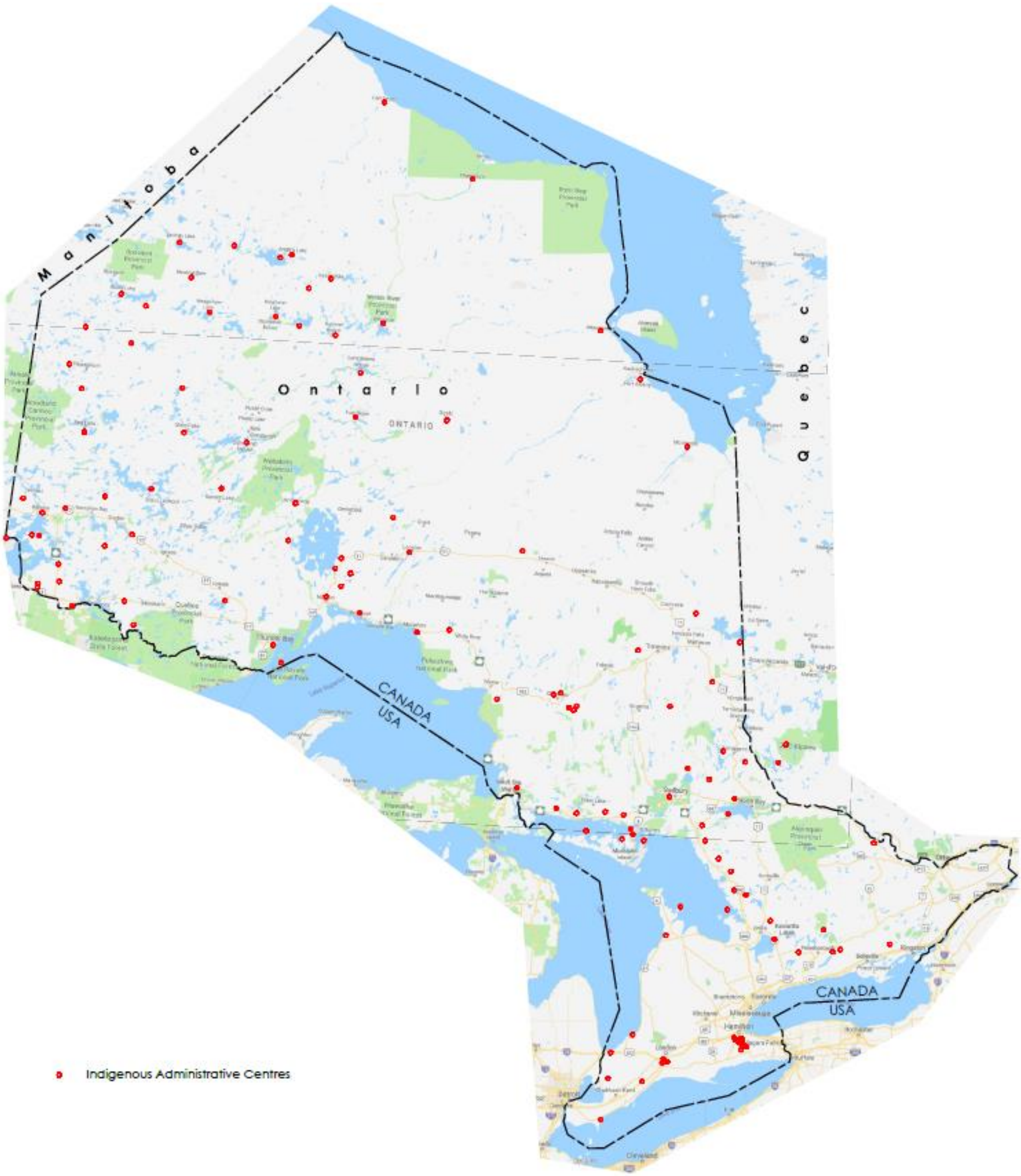
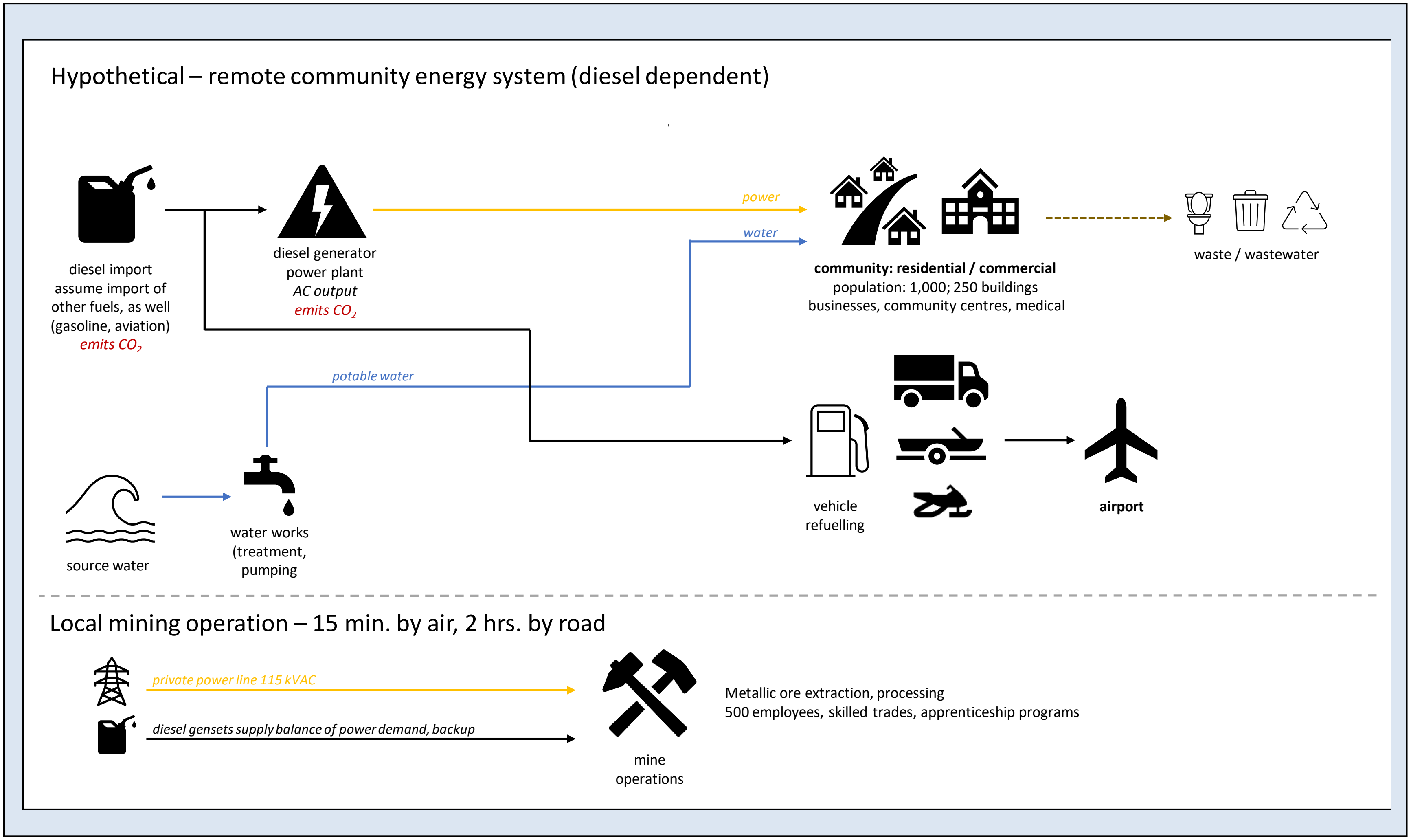


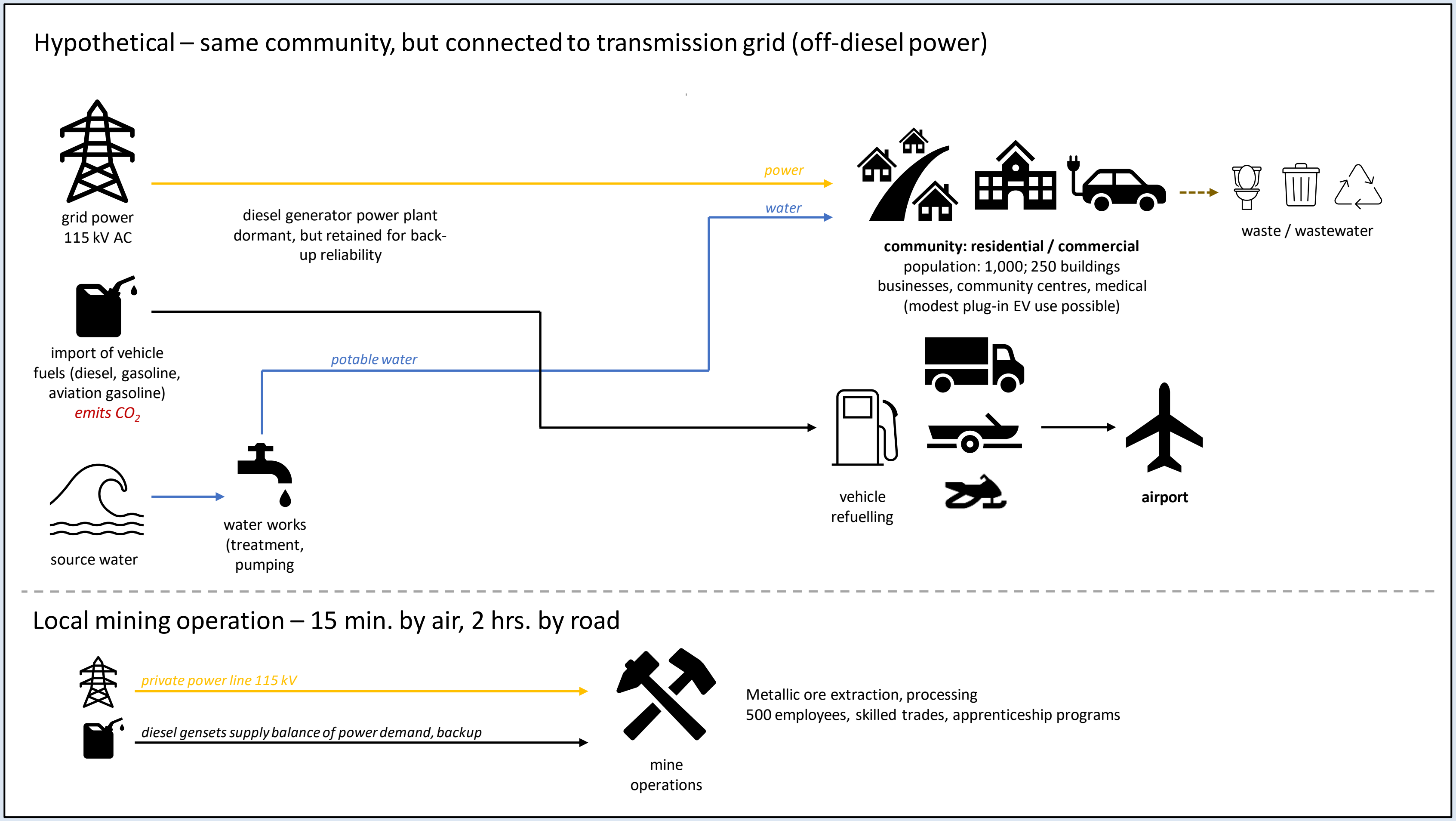
Figure 46: Indigenous Administrative Centers
Source: Adapted from Indigenous Services Canada [42]

Ontario Opportunity: hydrogen energy independence in remote and Indigenous communities

Remote and Indigenous communities that are isolated from power transmission grid, pipeline and highway infrastructure (or partly so) are often reliant on imports of diesel to fuel power generators for electrical loads, such as lighting, space heating and electronics. Delivering fuel to these communities is expense, creating economic burden, and limits options to improve energy prosperity. In some instances, hydrogen produced using local energy resources can yield new opportunities for remote communities to reduce reliance on diesel, as well as commercial development.

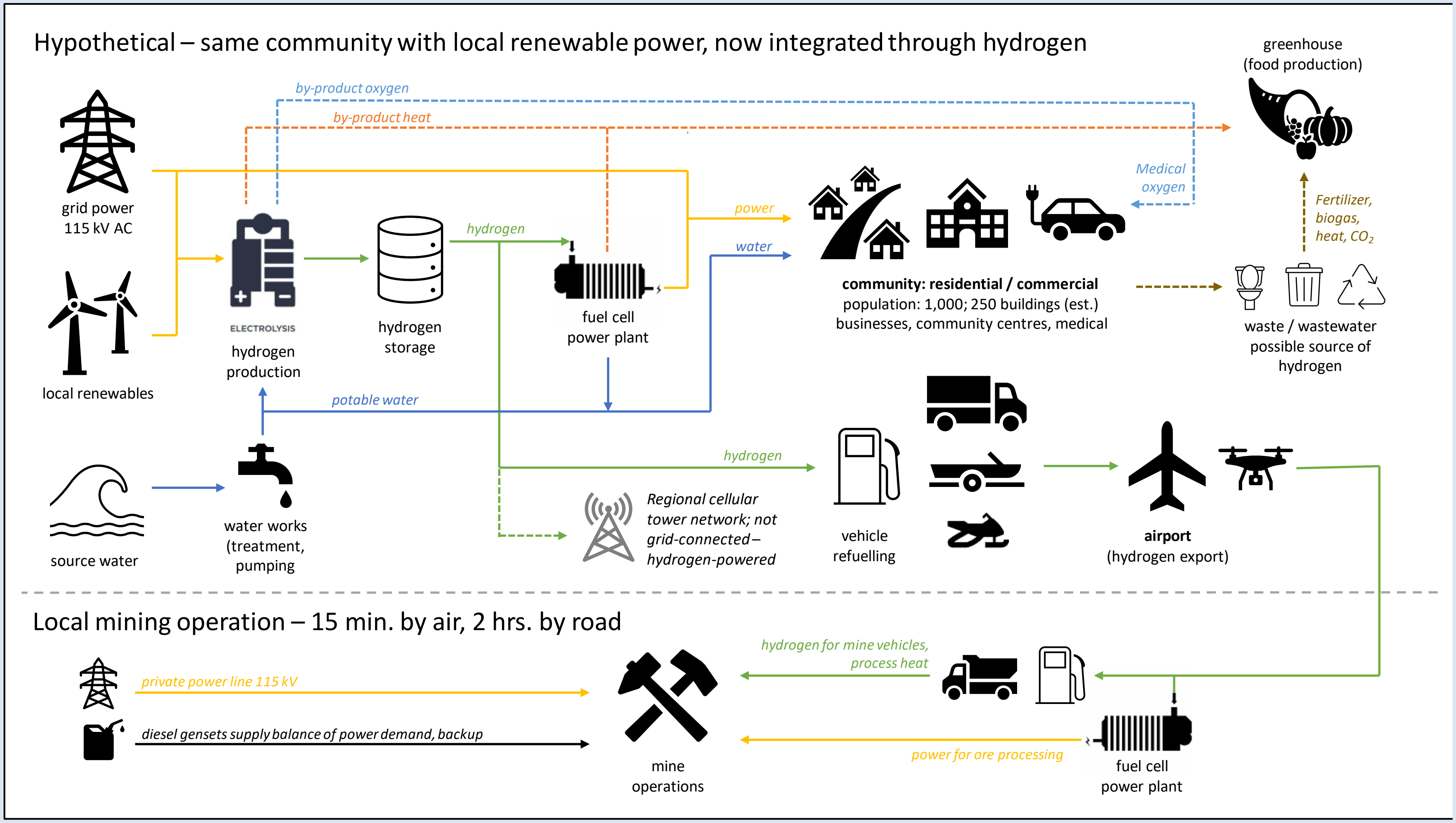
Consider the following example as a hypothetical First Nations community, having a population of approximately 1,000 individuals and a small airfield. The community is wholly reliant on diesel as its source of energy, which it must import (along with fresh produce). However, there is potential for renewable power generation, and a new transmission line is planned to connect the community to the regional grid. This is a welcome development, but the diesel power plant remains on back-up duty when grid power is interrupted. There is also a mine nearby, which is a source of employment for the community. Below is representation of the main energy and material flows through the community; first as it is, and then how it will be after becoming grid-connected.


Hypothetical – remote community energy system (diesel dependent)
diesel import
assume import of
other fuels, as well
(gasoline, aviation)
emits CO_2
diesel generator
power plant
AC output
emits CO_2
power
water
community: residential / commercial
population: 1,000; 250 buildings
businesses, community centres, medical
waste / wastewater
potable water
source water
water works
(treatment,
pumping
vehicle
refuelling
airport
Local mining operation – 15 min. by air, 2 hrs. by road
private power line 115 kVAC
diesel gensets supply balance of power demand, backup
mine
operations
Metallic ore extraction, processing
500 employees, skilled trades, apprenticeship programs



This First Nations community is now much less reliant on diesel, but it still requires fuel imports for vehicles and airfield operations. How might the picture change with the incorporation of hydrogen systems?

The introduction of hydrogen production on-site changes the picture significantly. It enables maximum productivity of local renewable power resources, supplements grid power and enables a transition to hydrogen-powered vehicles. By-product heat and oxygen from the hydrogen plant can serve local greenhouse and medical needs. Importantly, the community can over-produce hydrogen and deliver the surplus to the local mine (potentially by air), where it can help to green their operations, and reduce their reliance on diesel, too, as illustrated below. Note also the use of hydrogen to power local cellular transmission towers, which are not grid-connected, enabling greater connectivity and data bandwidth for the community.



4.5 Consolidated Base Map

For the sake of interpretation and analysis, the following two maps show the borders separating the administrative regions, all energy system corridors (i.e., transmission lines, natural gas pipelines) and power generating sites, and all transportation corridors (i.e. rail, highway, ports).

The second map has been colour coded to show all transportation and all energy corridors within the administrative regions.

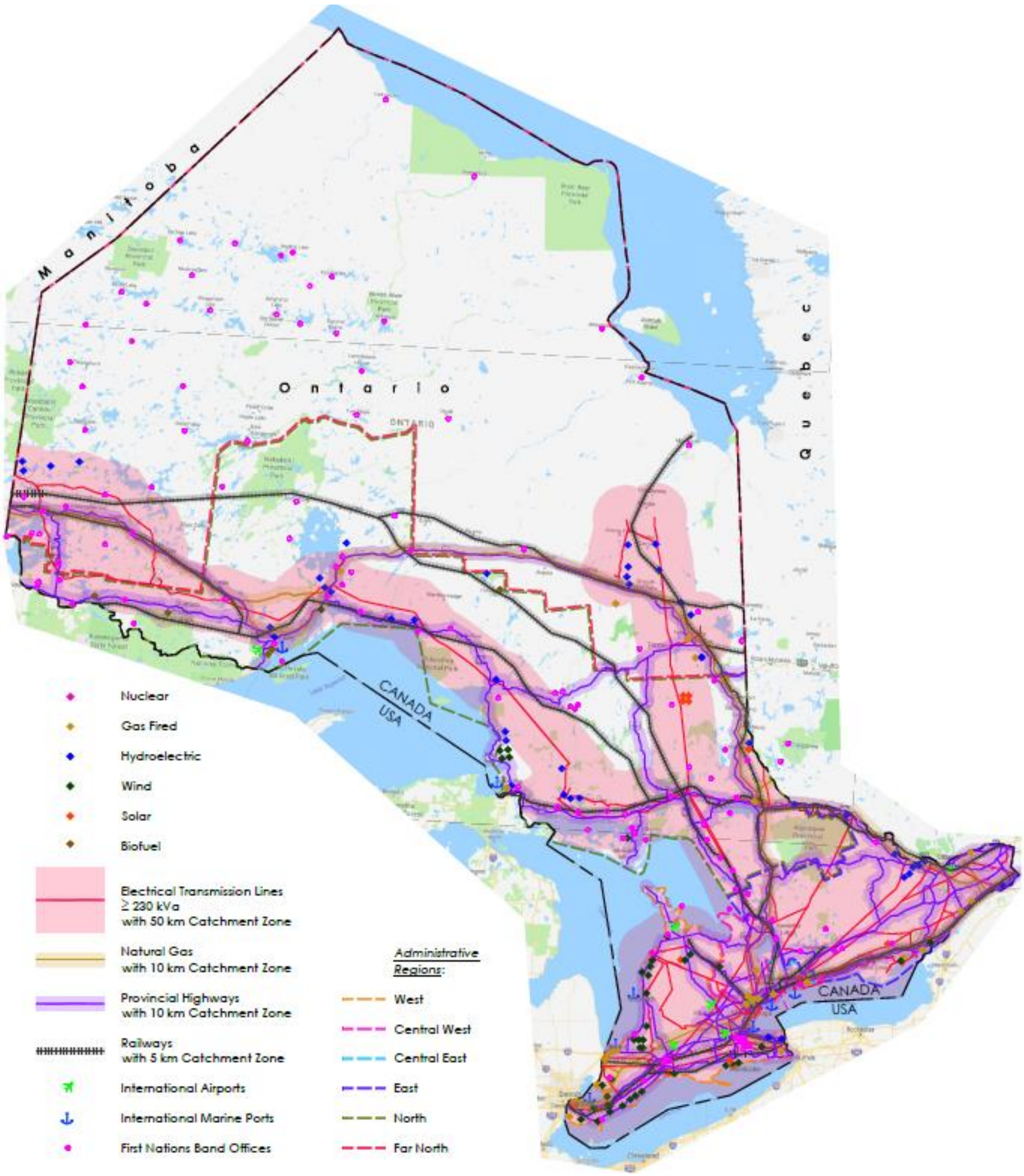


Figure 47: Consolidated Base Map

Source: Adapted from Government of Ontario [37], Railway Association of Canada [35], IESO [36], Canada Energy Regulator [43], OEB [44]

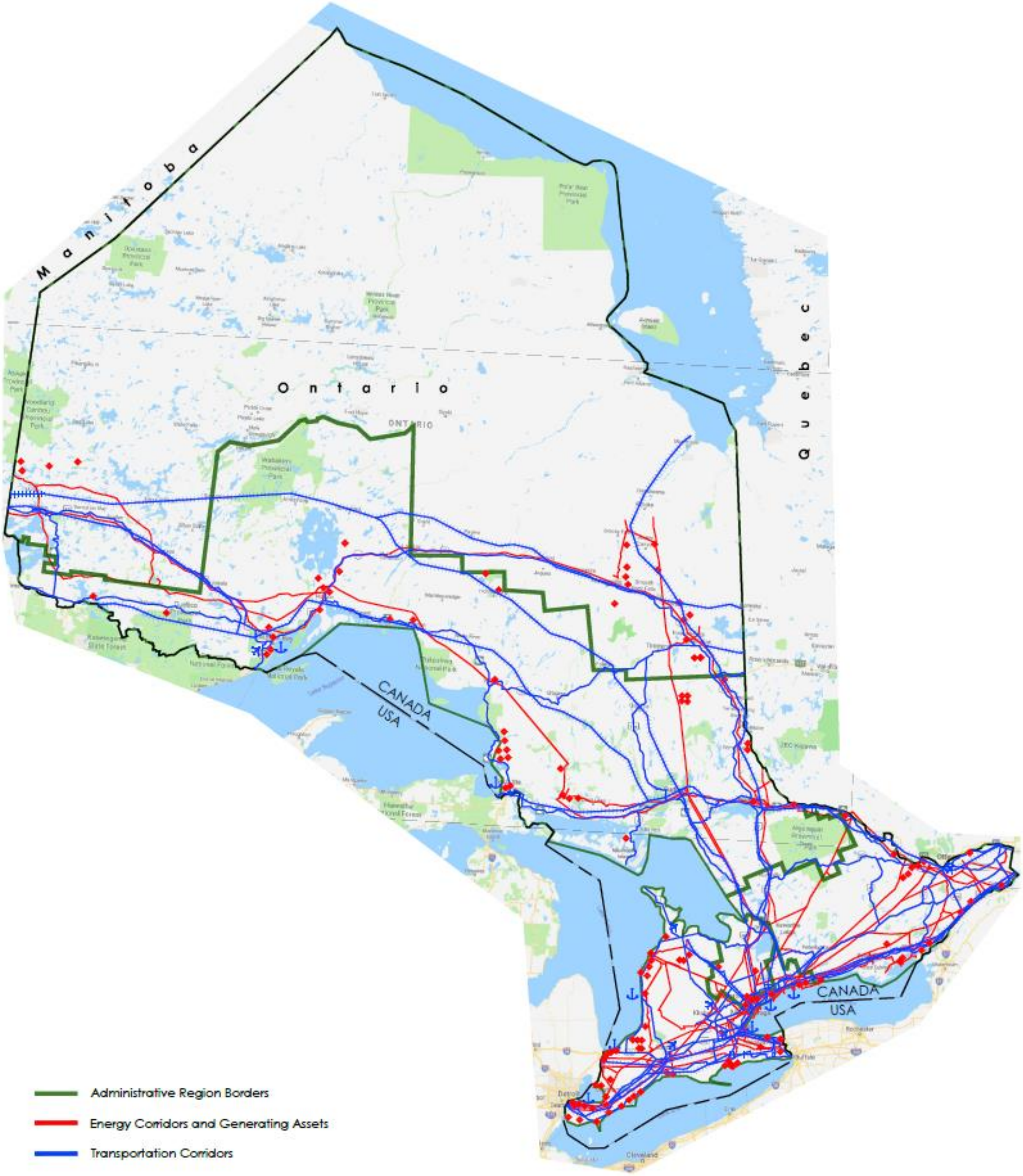


Figure 48: Transportation and Energy Corridors
Source: Adapted from Government of Ontario [37], Railway Association of Canada [35], IESO [36], Canada Energy Regulator [43], OEB [44]

5.0 MAPPING PROSPECTIVE AREAS OF CCUS ACTIVITY AND SUPPORTING INFRASTRUCTURE IN ONTARIO

This section presents a series of maps that show the current location of large, stationary emitters of CO_2, which are more appropriate for use of CO_2 capture technologies than smaller, distributed or mobile sources of GHG emissions. Section 2.0 of this report identifies prospective areas where CO_2 injection into deep saline aquifers or depleted oil and gas reservoirs might achieve some significant level of permanent sequestration (see Figure 26). These areas are mapped in this section alongside the major emitters and a hypothetical transport network is introduced that links the sources of CO_2 to potential areas of injection.

5.1 Industrial Point-Source CO_2 Emitters in Ontario

The mapping in the following pages indicates the locations of Ontario's 50 largest emitters of CO_2, according to GHG emissions data collected from industrial facilities subject to provincial quantification, reporting and verification regulations [45]. These data are publicly reported and apply to emitters of more than 10,000 tonnes per year. The study team chose to include only the top 50 for the analysis, as this represents more than 80 per cent of the total industry sector emissions inventory, and additional points on the map would not significantly inform the analysis.

The table below lists the top 50 CO_2 emitters by mass of annual CO_2 emissions, which is the specific GHG of focus in carbon capture and storage systems. For the analysis presented herein, the nature of the emitting facility is not relevant but the location is important. The emitters listed include iron and steel, lime and cement, and chemicals and petrochemicals as industry subsectors. In other words, these are facilities for which the carbon capture technologies described in section 2.0 are applicable (i.e., post-combustion, pre-combustion, recycle / oxyfuel combustion and industrial process stream capture of CO_2). Note that the ID number in the table corresponds to the emitting facility rank from highest (1) to lowest (50), and that the administrative region is marked (e.g., W for West, N for North, CE for Central East, and so on).

The top 50 CO_2 emitters contributed a total of 40 Mt CO_2 to industry sector GHG emissions in 2018. That year, there were total of 267 regulated facilities in Ontario, emissions from which summed to 49.8 Mt. Of this, 44.7 Mt is considered as fossil-source and 5.1 Mt is biogenic in origin.

Table E: Top 50 CO_2 Emitters

ID No.	Region	GHG ID No.	Facility Location	City / District / Municipality	CO_2 Tonnes (Fossil Emissions)	CO_2 from Biomass Tonnes (Biogenic Emissions)	CO_2 Emissions Total
1	W	G10091	1330 Burlington Street East	Hamilton	4,781,149		
2	W	G10646	7870 Sixth Line South	Halton Hills	4,779,686		
3	N	G10011	105 West Street North	Sault Ste. Marie	4,309,457		
4	W	G10276	2330 Regional #3 Road	Haldimand County	3,831,148		
5	W	G10255	602 Christina Street South	Sarnia	1,811,257		
6	CE	G10273	410 Bowmanville Aveenue	Bowmanville	1,519,655		
7	W	G10199	225 Concession 2	Nanticoke	1,179,224		
8	CW	G10192	2391 Lakeshore Road	Mississauga	1,012,155		
9	W	G10256	1475 Vidal Street South	Sarnia	968,800		
10	W	G10208	785 Petrolia Line	Corunna	952,441		
11	W	G10407	140 Bickford Line	Courtright	917,077		
12	E	G10171	6501 Highway 33 Highway West	Bath	775,633		
13	W	G10254	1900 River Road	Sarnia	756,591		
14	W	G10253	150 St. Clair Parkway	Corunna	722,289		
15	W	G10283	161 Bickford Line	Courtright	666,084		
16	E	G10223	1370 49 Highway South	Picton	533,531		
17	W	G10360	150 St. Clair Parkway	Corunna	531,546		
18	W	G10274	585 Water Street South	St. Marys	517,352		
19	W	G10050	600 Highway #5 Highway West	Dundas	511,532		
20	CW	G10191	385 Southdown Road	Mississauga	447,820		
21	W	G10051	374681 Oxford County 6 Road	Ingersoll	434,784		
22	CE	G10413	470 Unwin Avenue	Toronto	433,338		
23	W	G10251	602 Christina Street South	Sarnia	425,225		
24	W	G10114	3551551 35th Line	Woodstock	378,526		
25	CW	G10469	8600 Goreway Drive	Brampton	369,655		
26	W	G11793	1265 Vidal Street	Sarnia	301,907		
27	W	G10554	790 Petrolia Line	Corunna	299,962		
28	W	G10250	602 Christina Street South	Sarnia	273,235		
29	W	G10275	386 Wilcox Street	Hamilton	248,501		
30	FN	G10765	End of Highway 652	Cochrane	223,526		
31	W	G10133	755 Parkdale Avenue North	Hamilton	222,165		
32	N	G10093	1 Station Road	Espanola	221,612	761,597	
33	CE	G10319	1550 Wentworth Street	Whitby	219,559		
34	N	G10165	505 Archer's Drive	Kirkland Lake	218,607	176,912	
35	N	G11078	18 Rink Street	Copper Cliff	190,666		
36	N	G10025	2001 Neebing Avenue	Thunder Bay	169,335	1,107,542	
37	W	G10622	90 Allanburg Road	Thorold	165,719		
38	W	G10559	535 Rokeby Line	Mooretown	156,899		
39	W	G10252	1182 Plank Road	Sarnia	152,665		
40	W	G11743	477 Oil Springs Line	Courtright	149,397		
41	W	G10482	1555 Elm Street	Port Colborne	141,748		
42	W	G10075	275 Bloomfield Rad	Chatham	139,037		
43	N	G11496	5967 Highway 11/71 PO Box 5	Emo	134,276		
44	CE	G10459	0 120 Pearl Street	Toronto	132,831		
45	N	G10043	17 Highway 17 Highway East	Blind River	129,069		
46	W	G10057	1100 Green Valley Road	London	125,672		
47	E	G10614	1040 County Rd 17 Road	L'Orignal	124,936		
48	N	G10398	2 Longyear Drive	Falconbridge	123,889		
49	N	G10077	175 Industrial Road	Copper Cliff	119,885		
50	E	G10177	0 7263 33 Highway	Greater Napanee	116,957		
					38,068,009	**2,046,051**	**40,114,060**

Large Final Emitters in Ontario – 267 total $C0_2$ emitters as reported in 2018.

Fossil Fuel Emissions = 44,691,726
Biogenic Emissions = 5,084,197
Total CO_2 Emissions = 49,775,923

The Top 50 numbered emitters are shown on the following maps.

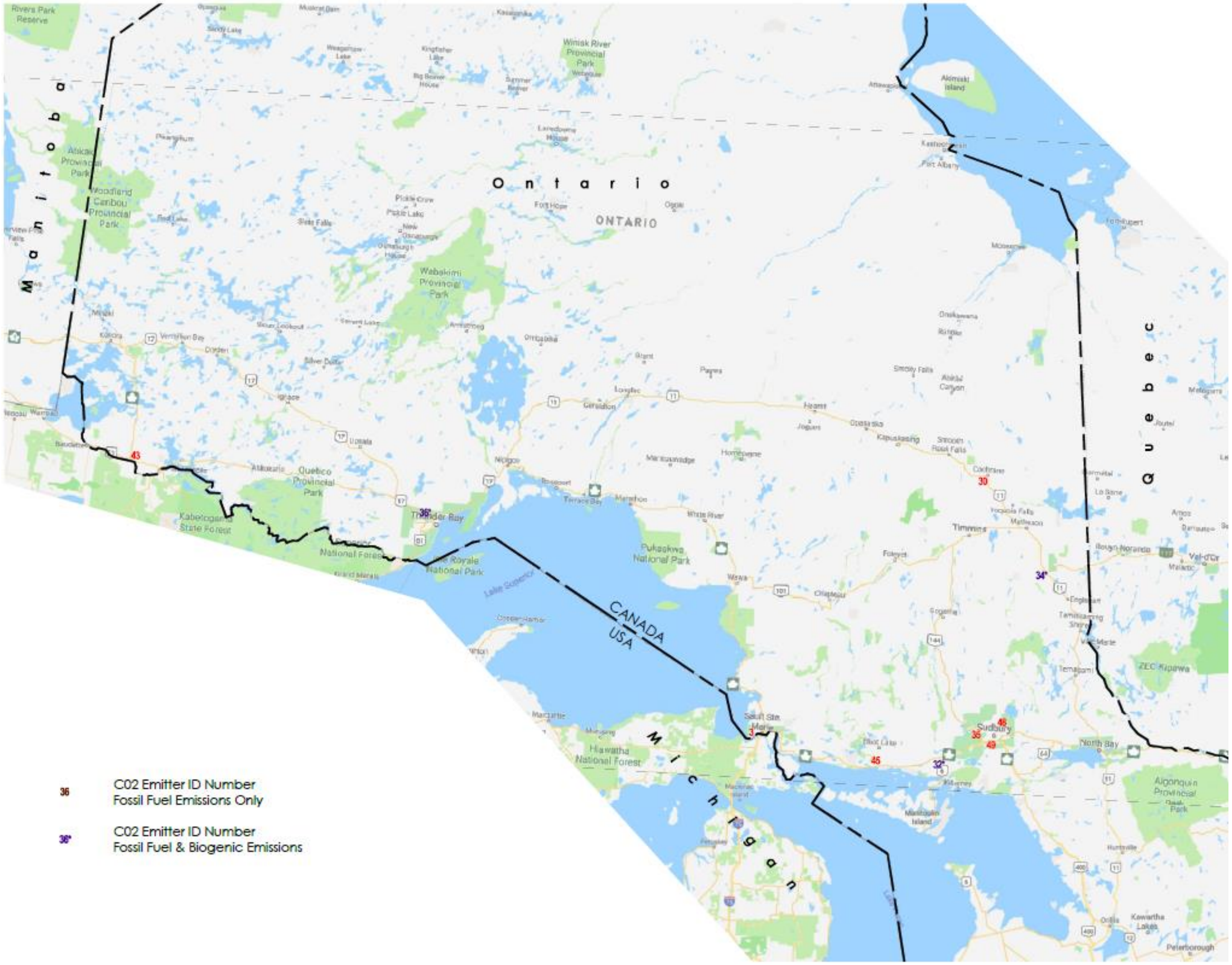


Figure 49: Top 50 CO_2 Emitters: North Region
Source: Adapted from Hughes [46]

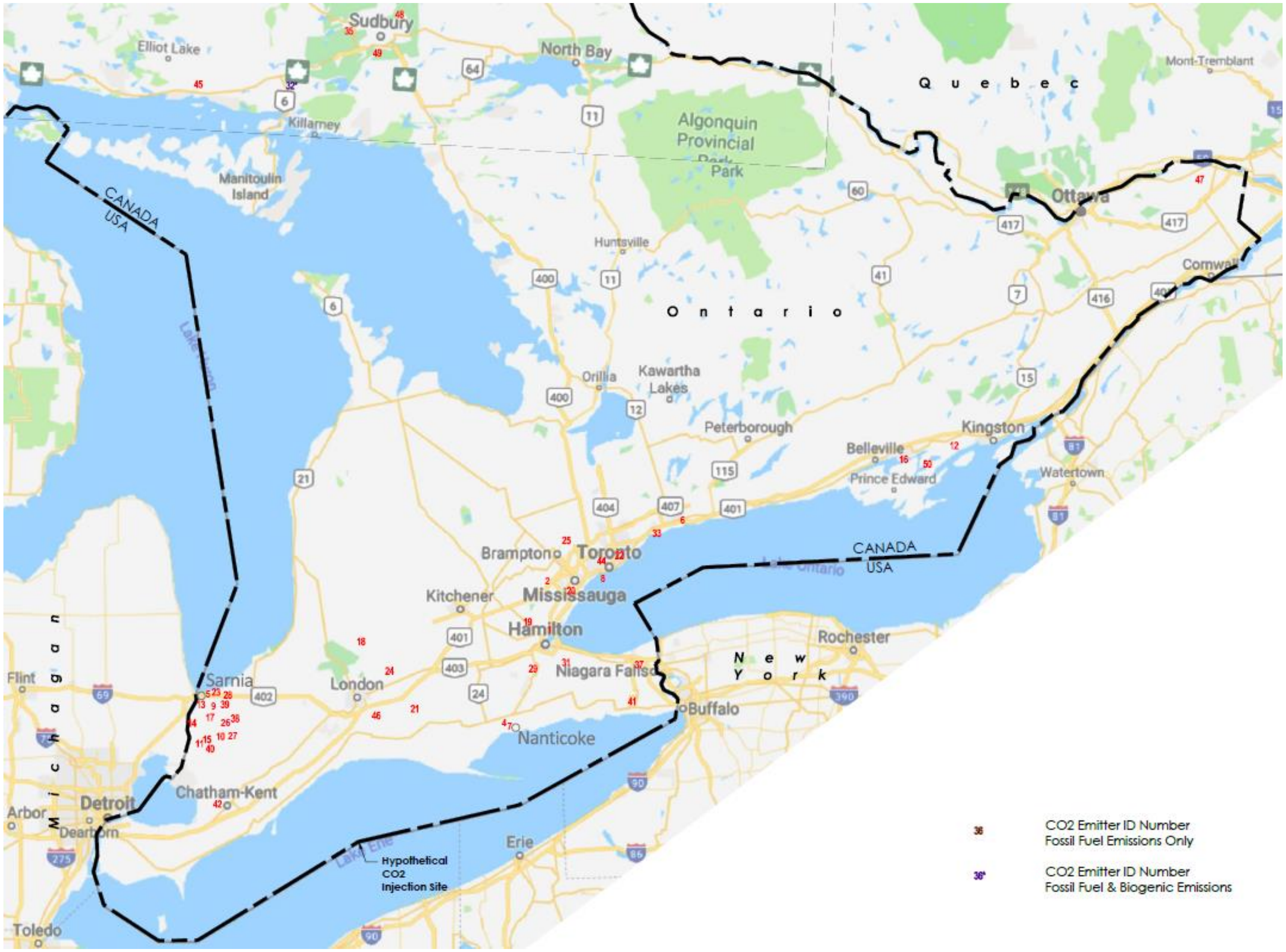


Figure 50: Top 50 CO_2 emitters: South Region
Source: Adapted from Hughes [46]

5.2 Industrial CO_2 Emitter Clusters in Ontario

Shown is a visualization of the amount of CO_2 emissions generated by all Ontario CO_2 emitters (267 in total in 2018) grouped by proximity to each other. That is, geographic clusters of emitters are considered as parts of a regional whole. The circles are roughly centered over the collective midpoint of the emitting facilities for a specific group or locality, and the size of the circle is proportionally scaled to the sum of the CO_2 emissions from the cluster, as in a bubble chart. The purpose of this visualization is to identify the regions of the province where captured CO_2 might be efficiently accumulated for transport to a point of CO_2 injection for sequestration, since the points of emission and injection do not always coincide. Where large volumes of CO_2 can be gathered, transport by pipeline may be most cost-effective. Otherwise, transport by rail or marine are probably the only alternatives. If none of these modes can service the emitter, then it is considered isolated.

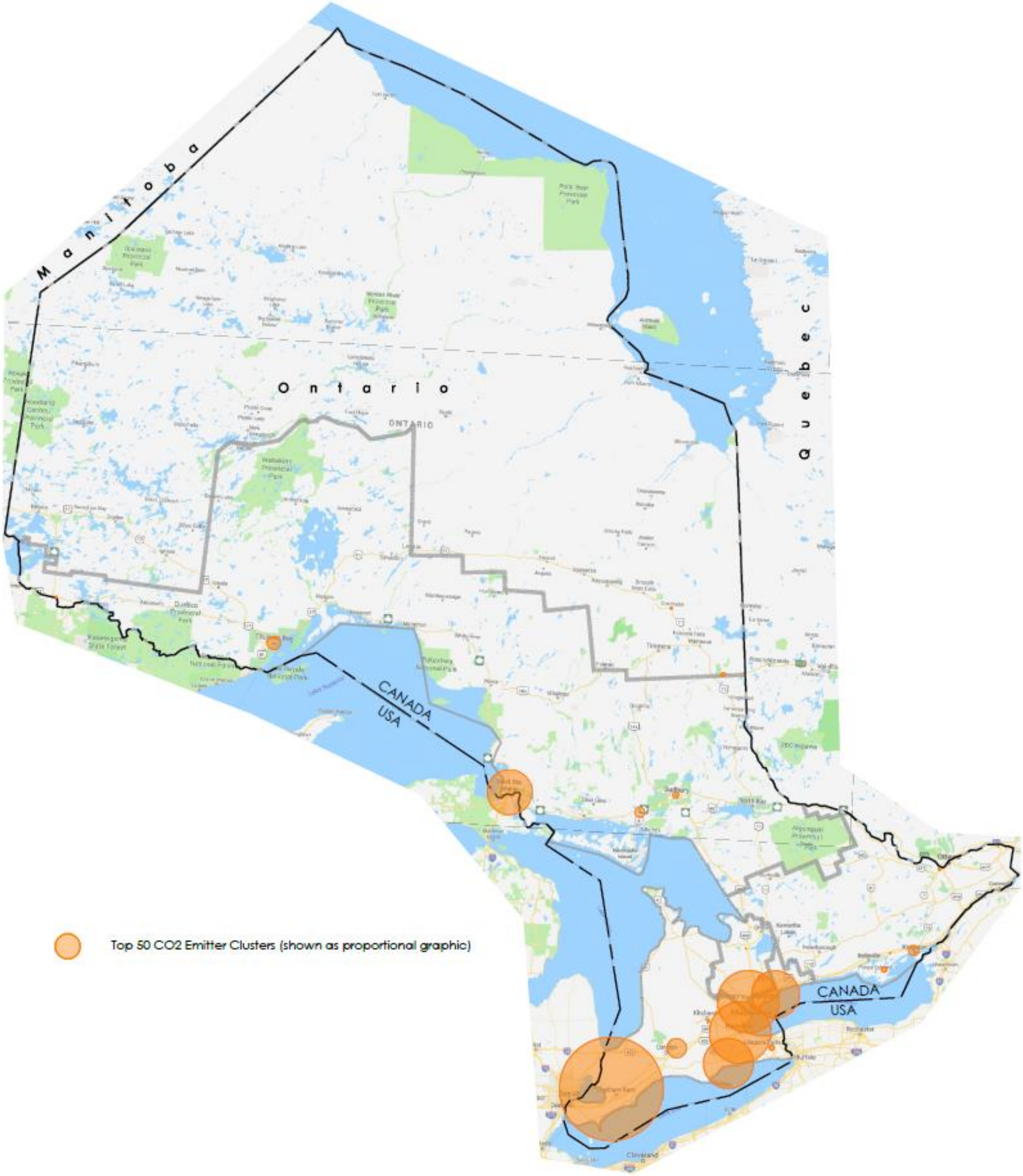


Figure 51: Industrial CO_2 Emitter Clusters

5.3 Conceptual CO_2 Storage Reservoirs, Areas of Injection, and Transport Corridors

To illustrate how a multimodal network for moving CO_2 from points-of-capture to points-of-injection might appear, the study team hypothesized a system of pipelines, railway and marine shipping routes that could be used as part of a permanent sequestration strategy. **The map presented here should not be interpreted as a recommendation of the study team**. The feasibility of developing and operating such a network is beyond the scope of this report and is dependent on many assessments and investment decisions yet to be made. Instead, this map is presented purely as a conceptual visualization of how CO_2 might be managed after it is captured at large, stationary, emitting facilities in Ontario. The characteristics of this scenario are as follows:

- Geological formations into which CO_2 can be injected for permanent sequestration include
  - the Mount Simon Formation saline aquifer at depths of greater than 800m, parts of which can be accessed from within Ontario's boundaries (shown on map) but most of which is in the U.S. Midwest (i.e., the State of Michigan and Pennsylvania);
  - depleted oil and gas reservoirs in parts of southern Ontario, duly assessed and confirmed viable, with promising formations near Sarnia and around Haldimand, Welland, Brant and Norfolk counties;
  - sedimentary basins in Atlantic Canada and in its offshore regions, which could yield vastly more sequestration potential than can be realized in Ontario (i.e., centuries of storage capacity as opposed to decades);
- Transport of CO_2 overland by pipeline would follow rights-of-way for existing natural gas pipeline, where volumes warrant, and railways where volumes are lower (this is not to imply that existing rights-of-way are useable for CO_2 pipelines – it is simply a convenient reference for illustrative purposes);
- Bulk marine shipping through the Great Lakes is also contemplated as an option, especially if shipping down the St. Lawrence River to Atlantic repositories.

This scenario mapped shows CO_2 pipeline service intersecting the emitter clusters near Sarnia, the Greater Toronto & Hamilton Area, and the Niagara region. CO_2 accumulated in this network is transported for injection to the idealized point in Lake Erie (or near the shore), as previously described in section 0, for sequestration in the Mount Simon Formation, or into the areas where depleted oil and gas reservoirs may exist, as shown. It can also be piped eastward along the north shore of Lake Ontario, across the border with Quebec and onward to storage opportunities in the Atlantic region. The pipeline network crosses the border into the U.S. at three points: from Sarnia and from Sault Ste. Marie into the State of Michigan, and from Fort Erie into New York State en route to Pennsylvania. Note that this presumes the hypothetical existence of a cross-border, international and inter-regional CCUS agreement to jointly share and steward the Mount Simon Formation storage resource in the Michigan and Appalachian Basins between Canada and the U.S. Also shown is the use of either pipeline or railway corridors to move CO_2 from Cochrane to North Bay, and then through Sudbury to Sault Ste. Marie, where it could be exported to Michigan. Lastly, this export node could receive captured CO_2 from Thunder Bay via bulk carrier over Lake Superior.

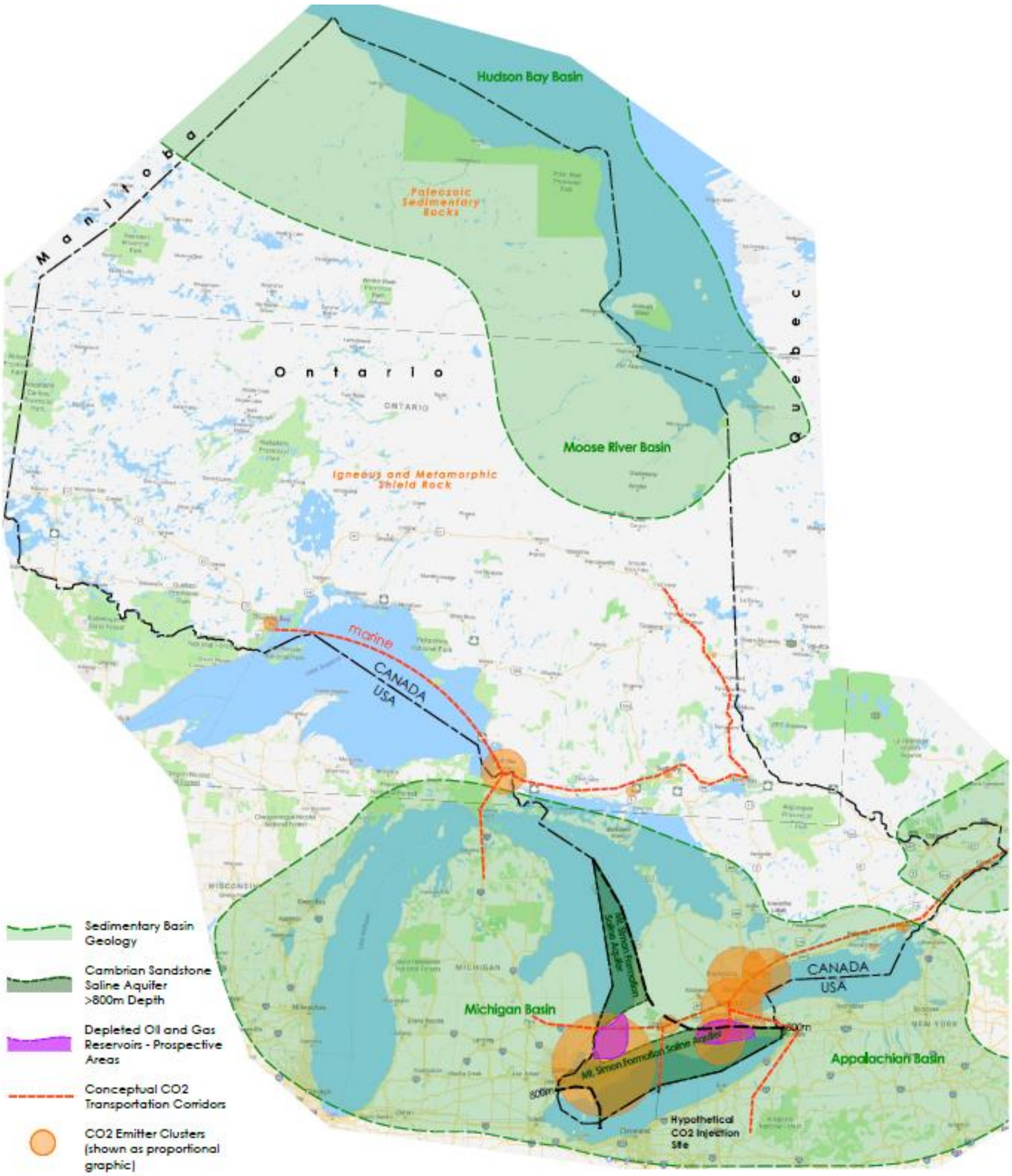


Figure 52: Conceptual CO_2 Reservoirs, Emitters, Areas of Injection, and Transportation Corridors

This report does not include a technoeconomic assessment of mobilizing and transport CO_2 in bulk. However, estimates of the capital expense and operating expenditures associated with different modes of transporting CO_2 have been published by various parties, and these can help to inform and frame future work for a prospective Ontario network. Indeed, the CanmetENERGY National CCUS Assessment Framework provides analytical and modeling tools for this purpose. As a sample point of reference, the Advisory Council of the European Technology Platform for Zero Emission Fossil Fuel Power Plants produced a report in 2011 [47] that presents the following table of cost estimates. These represent a large-scale transport scenario in which 20 megatonnes of CO_2 flow annually through a network of suppliers and consumers linked by a central spine to which various smaller feeders connect.

Table F: Cost estimates for large-scale CO_2 networks

Transport mode	**Cost, € / tonne-CO_2**			
Spine distance	*180 km*	*500 km*	*750 km*	*1500 km*
Onshore pipe	1.5	3.7	5.3	n/a
Offshore pipe	3.4	6.0	8.2	16.3
Marine shipping (including liquefaction)	11.1	12.2	13.2	16.1

Source: Adapted from The Costs of CO_2 Transport, Post-demonstration CCS in the EU [47]

The key message from this analysis is that pipeline costs scale up with distance, while bulk marine shipping is less sensitive to the effects of scale.

6.0 MAPPING PROSPECTIVE HYDROGEN MARKETS AND STORAGE SITES

In this section, prospective sites for subsurface hydrogen storage in Ontario are introduced for consideration by the reader. These are hypothetical sites based on the judgement of the study team, and do not represent specific recommendations. In choosing sites for hydrogen storage, proximity to supply opportunities and concentrations of demand are important. So, a series of maps are presented in this section that represent geospatial visualization of hubs of hydrogen activity within the province. These hubs of market activity borrow from analysis presented in the companion report by H2GO Canada, *Estimating Low-Carbon Hydrogen Supply and Demand in Ontario to 2050, Based on an Assessment of Effective Value Chain Development*.

6.1 Hydrogen Markets in Ontario

The study team undertook to speculate on the likely areas in which significant hydrogen production could occur, based on a fortuitous confluence of feedstock availably, including input energy commodities, supporting infrastructure and proximity to established industrial facilities that could either feed production or anchor demand for hydrogen. A list of 28 prospective sites emerged from this analysis, appearing in

Table G, below. The key qualifications were:

- proximity to potential consumer markets with increasing demand for low-carbon hydrogen across numerous sectors and applications;
- feedstock availability consistent with low-carbon hydrogen production methods, namely
    - steam methane reforming (SMR) due to proximity to operating natural gas pipelines, and
    - grid-supplied electricity to power water electrolysis, necessitating a modest distance to power transmission corridors;
- where distributed consumer markets are not nearby but where large, discrete industrial users could sustain demand, production potential is added to the list.

Table G: Prospective Hydrogen Production Points

H2 Production	Production Pathway	Map Label	Region
1	Grid Electricity	CA	Far North
2	Grid Electricity	CB	North
3	Grid Electricity	CC	North
4	Grid Electricity	CG	North
5	Solar Electricity	AD	North
6	Wind Electricity	BD	North
7	SMR with CCU	EA	North
8	SMR with CCU	EB	North
9	Forest Biomass	DA	North
10	Grid Electricity	CF	West
11	Solar Electricity	AA	West
12	Solar Electricity	AB	West
13	Wind Electricity	BA	West
14	Wind Electricity	BB	West
15	Wind Electricity	BC	West
16	SMR with CCUS	EF	West
17	SMR with CCUS	EG	West
18	SMR with CCUS	EH	West
19	SMR with CCUS	EI	West
20	SMR with CCU	EJ	West
21	Grid Electricity	CE	Central West
22	SMR with CCUS	EE	Central West
23	Grid Electricity	CH	Central East
24	Grid Electricity	CI	Central East
25	Grid Electricity	CD	East
26	Solar Electricity	AC	East
27	SMR with CCU	EC	East
28	SMR with CCUS	ED	East

The entries in the above table are identified by the dominant hydrogen production pathway characteristics (e.g., feedstocks, methods of production), and the administrative region in which it occurs. Also, a corresponding, double-lettered label appears that represents the siting on the map that follows. The first letter in the pair refers to a general pathway option; the second is simply a sequence marker:

A. solar power to electrolysis
B. wind power to electrolysis
C. grid power to electrolysis
D. forest biomass-fired power to electrolysis
E. natural gas to steam methane reforming (or autothermal reforming) with or without CCUS (as the siting is not directly dependent on the presence of carbon capture)

Shown on the map below are existing high-voltage transmission corridors and natural gas pipelines (as their catchment areas, shaded), power generating assets, including solar, wind, nuclear, hydroelectric, and plants fired using natural gas and using biomass, and major power substations, as identified in the legend.

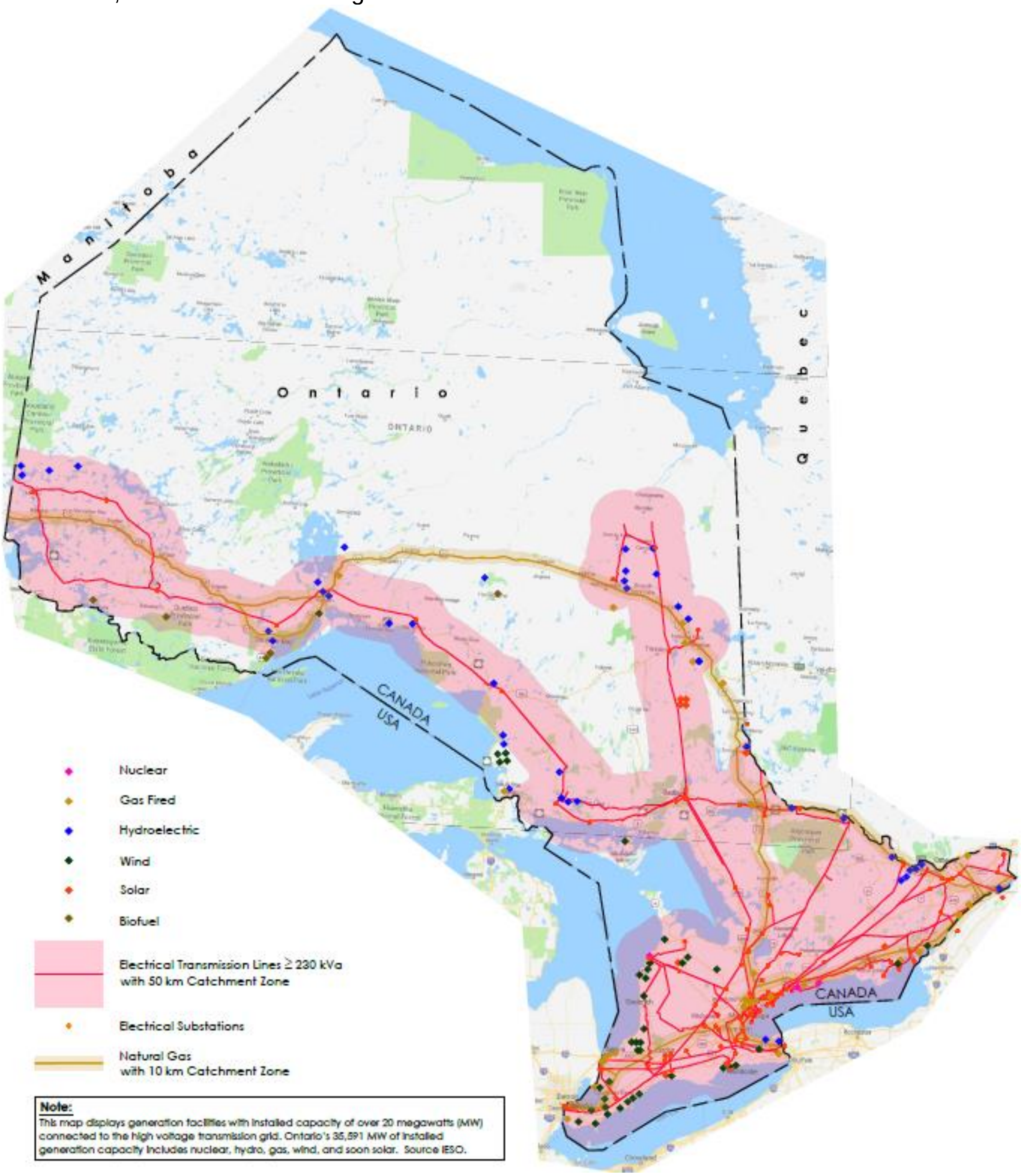


Figure 53: Energy Corridors

Building on the prospecting of major production sites, the study team next developed a set of emerging hydrogen markets (also called hydrogen hubs) according to the following criteria:

- large urban population centres in each region, including the ten most populous cities in Ontario, were selected to represent a multi-sector (i.e., commercial, residential, transportation), diverse range of hydrogen end-use applications.
- presence and proximity of industrial end-use applications of hydrogen contributed to hub assignment.
- urban areas close to one another were considered to represent a consolidation of demand that supported hub assignment.
- where communities were too small or remote within a region to support an urban population-centred end-use market, a representative hub was assigned to the administrative region (this serves to ensure that the balance of Ontario's entire population outside of urban centres is considered in the hydrogen supply and demand modeling conducted for the companion report); and
- as a corollary to the above criteria, each administrative region was ensured to have at least one market hydrogen hub to serve the population, regardless of distribution and density.

Thirteen market hubs were geographically assigned, as well as five representative hubs to serve the remaining, populations within the administrative regions (i.e., "Rep" hubs). A list of all hydrogen market hubs is provided in the following table.

Table H: Prospective Hydrogen Market Hubs

Model ID	City	Region	Map ID
Market 1	Rep Far North	Far North	-
Market 2	Thunder bay	North	1
Market 3	Sault Ste. Marie	North	2
Market 4	North bay& Sudbury	North	3
Market 5	Rep North	North	-
Market 6	Hamilton	West	4
Market 7	Niagara, Welland, St. Catherines	West	5
Market 8	Kitchener/ Waterloo	West	6
Market 9	London	West	7
Market 10	Windsor/Sarnia	West	8
Market 11	Rep West	West	-
Market 12	Central West (Peel, York)	Central West	9
Market 13	Barrie	Central West	10
Market 14	Rep Central West	Central West	-
Market 15	Central East (Toronto, Durham)	Central East	11
Market 16	Kingston	East	12
Market 17	Ottawa & Kanata	East	13
Market 18	Rep East	East	-

The hydrogen market hub assignments are presented in the following map, where blue circles represent the urban markets served and the red circles represent the region served (having no population-centred hub).

Figure 54: Prospective H_2 Production Points and H_2 Market Hubs

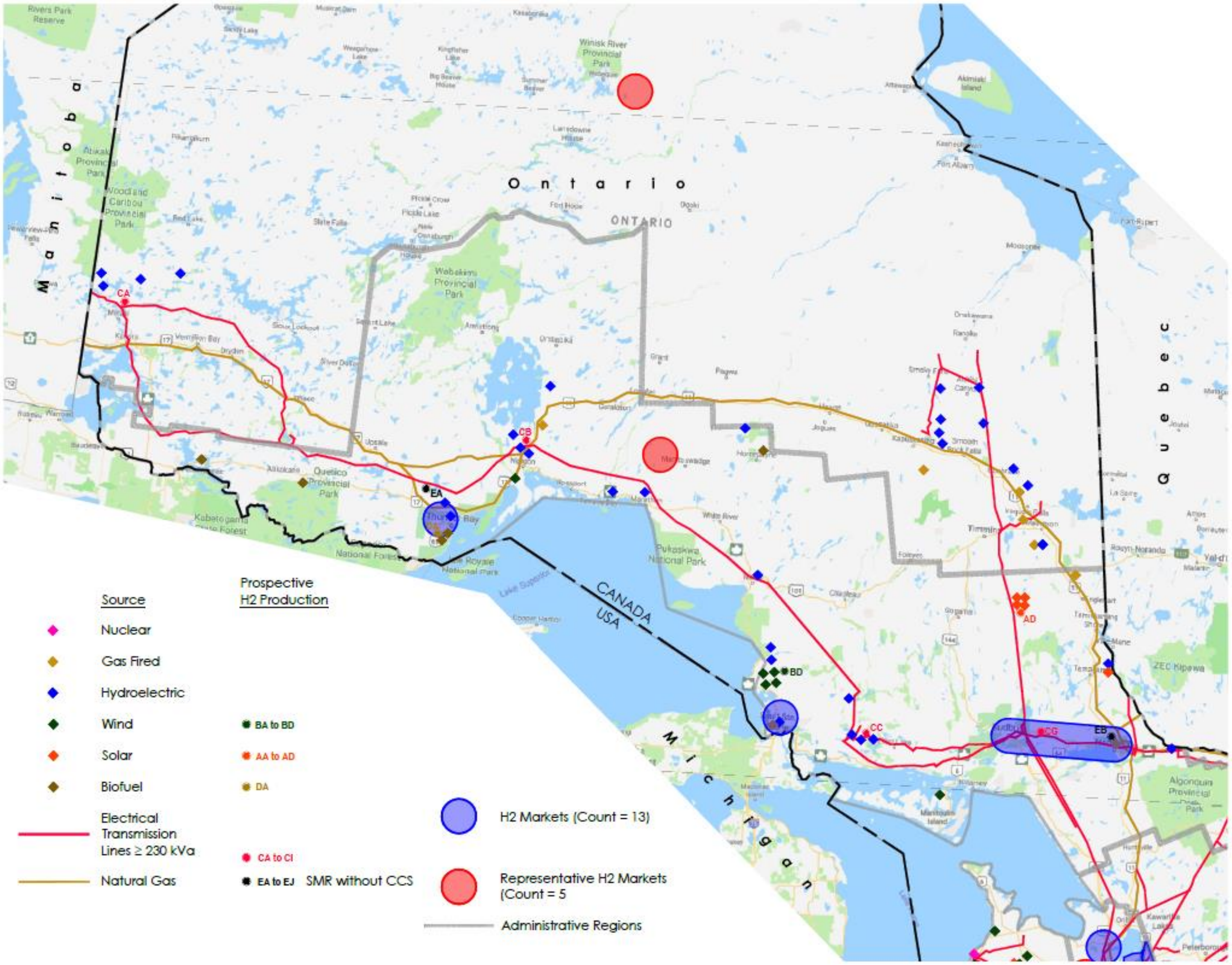


Figure 55: Prospective H_2 Production Points and H_2 Market Hubs: Northern Ontario

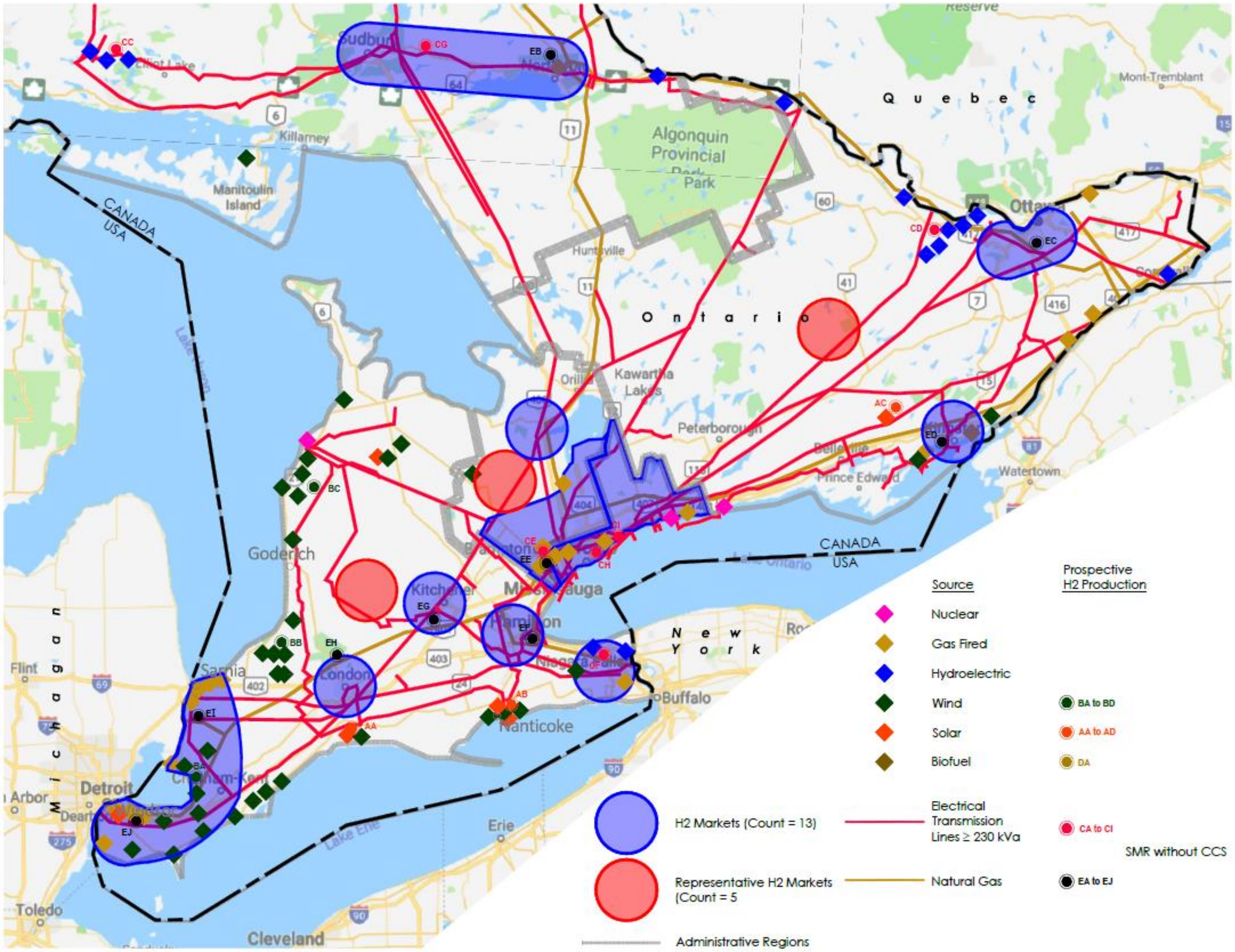


Figure 56: Prospective H_2 Production Points and H_2 Market Hubs: Southern Ontario

These 18 Ontario hydrogen hubs are briefly characterized as follows:

Market 1:	Representing the provincial population and remote communities in the Far North region to ensure inclusion in opportunity assessments.
Market 2:	Thunder Bay is one of the largest cities in northern Ontario, representing 17 per cent of the population in the north region. Thunder Bay also hosts one of the province's industrial heartlands in the North region.
Market 3:	Sault Ste. Marie is located very close to the U.S. border, making it well-connected to international markets and is also central to industrial supply chains. This market represents 11 per cent of the North region's population.
Market 4:	North Bay and Sudbury are combined to make up another 25 per cent of Ontario's population in the North region. Based on the proximity of these cities within the region, it reasons to consolidate them into a single hydrogen market, from which economic efficiencies can be leveraged.
Market 5:	Representing the population in the North region outsides of markets 2, 3 and 4, thus accounting for the service of smaller and remote communities with hydrogen opportunities.
Market 6:	Hamilton is a major industrial centre in Ontario and represents 16 per cent of the population in the West region.
Market 7:	Niagara, Welland and St. Catharines are cities in close proximity and near the U.S. border. Also having major transportation corridors, this market hosts 11 per cent of the West region's population.
Market 8:	Kitchener and Waterloo are major cities outside of the GTHA that are near each other and represent 12 per cent of the population in the West region. Kitchener is also a city with significant industrial activity and is a centre of technology innovation.
Market 9:	London is another major city outside of the GTHA representing 11 per cent of the population in the West region.
Market 10:	Windsor and Sarnia are both cities bordering U.S. and its substantial markets. Notably, Sarnia hosts one of Ontario's heaviest concentrations of industrial facilities.
Market 11:	Representing the remaining West region outside of markets 6 through 10.
Market 12:	Peel and York are regions within the GTHA that include some of the largest cities in Ontario. Pearson International Airport also falls within this region. 82 per cent of the population of the Central West region are within Peel and York.
Market 13:	Barrie is the ninth-largest city in Ontario, and is expected to generate significant demand for hydrogen.
Market 14:	Representing the remaining 14 per cent of the population within the Central West region.
Market 15:	Includes the City of Toronto and Durham region, representing 100 per cent of the population of the Central East region. This is the largest of the six administrative regions defined and the most populated city in Canada.

Market 16: Kingston represents 24 per cent of the population in the East region and is critically well-positioned between Toronto and Ottawa, geographically, enabling hydrogen fuelling between the two hubs.

Market 17: Ottawa and Kanata are the most populated cities in the East region, representing 64 per cent of the population. Ottawa is the capital of Canada and borders Quebec, which is expected to have thriving hydrogen markets.

Market 18: Represents the remaining communities in the East region.

It is important to note there are several major industrial facilities in Ontario that do not fall within one of the identified market hubs. Some are also large emitters of CO_2 that could be served by hydrogen as a pathway to decarbonize their operations. An example is in the Nanticoke area, where there are two major emitting facilities. These facilities could be major producers or users of low-carbon hydrogen, but because the do not align with the population centre criteria defined above, this location does not appear on the map as a geographic-specific hydrogen market hub. Therefore, the large emitter sites that were previously identified and numbered on the maps in Figure 49 and Figure 50 are repeated in the figure below, alongside the prospective market hubs (population- and region-based). Indigenous administrative locations are also included in this map, as Indigenous enterprises could lead the development of many hydrogen production, distribution and exporting operations in Ontario.

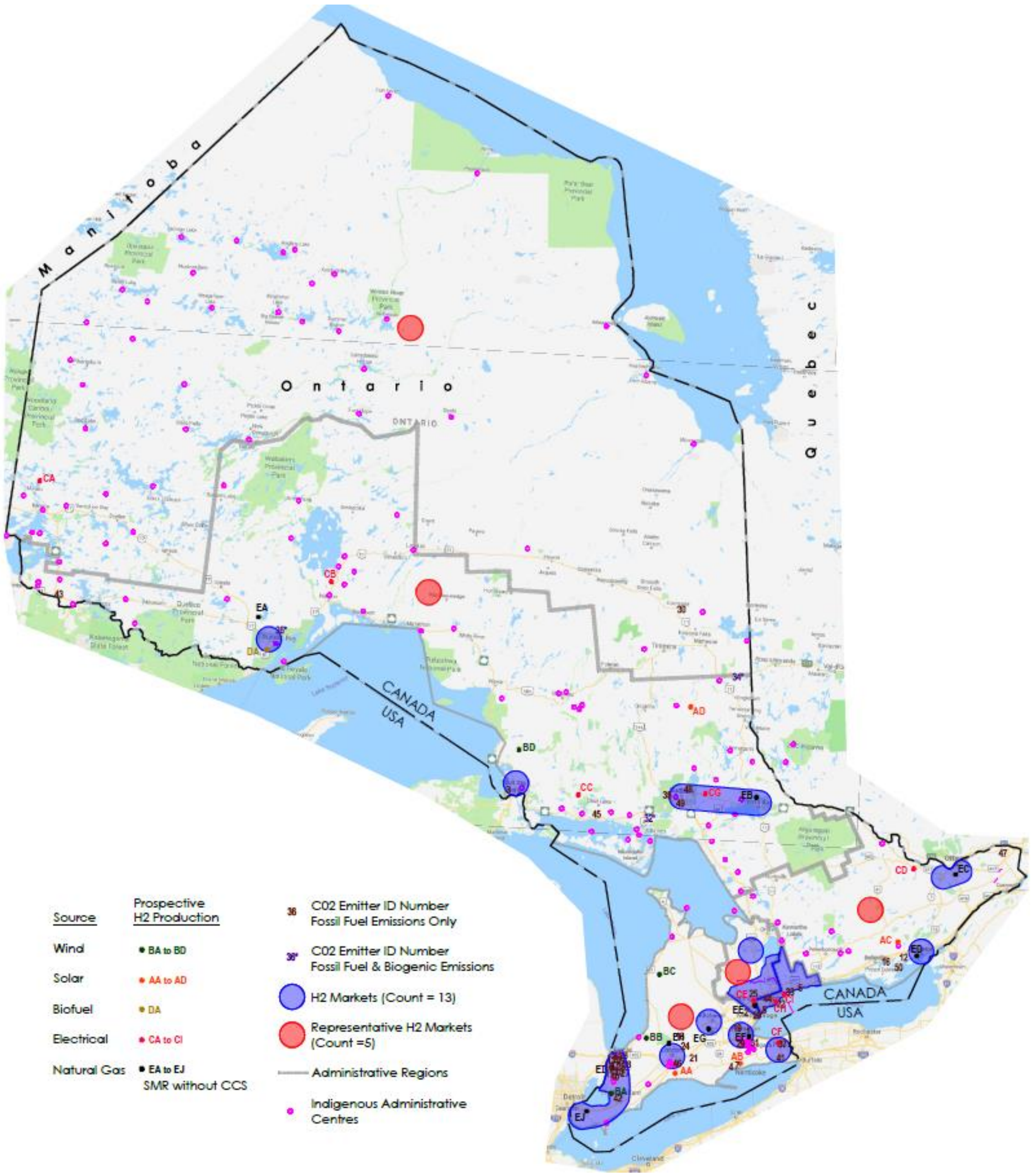


Figure 57: H_2 Market Hubs, Top 50 CO_2 Emitting Facilities, and Indigenous Administrative Centres

6.2 Hydrogen Import and Export for Ontario

Based on findings presented in the companion report by H2GO Canada, *Estimating Low-Carbon Hydrogen Supply and Demand in Ontario to 2050, Based on an Assessment of Effective Value Chain Development*, asymmetries in provincial hydrogen production and demand are expected under most practical scenarios. As with all other energy commodities flows in Ontario, imports and exports serve to maintain a balance of supply and demand. This study does not include an estimation of import-export volumes, but the mapping work provides some insight into the points of cross-border trade in low-carbon hydrogen with neighbouring jurisdictions. The following map shows the study team's prospective siting of import and export routes for hydrogen used and produced within the province, as well as the previously identified hydrogen production sites, as a hypothetical exercise to inform planning and strategy development.

Figure 58: Hypothetical Hydrogen Import and Export Border Crossings

6.3 Hydrogen Geological Storage – Prospective Areas

Previously, in Figure 41 of Section 3.3.1, a map of prospective areas having hydrogen subsurface reservoir potential is presented. This mapping is repeated here, but overlaid with additional information from the analysis covered in this section. Based on the sites of large, low-carbon hydrogen production potential, the identified market hubs, and the import-export routes from the previous section, the study team proposed six points of interest where specific types of underground hydrogen storage capacities could be considered for development. In southern Ontario, these consist of salt cavern storage and use of depleted oil and gas reservoirs; and in northern and eastern areas, hard rock cavern storage is proposed.

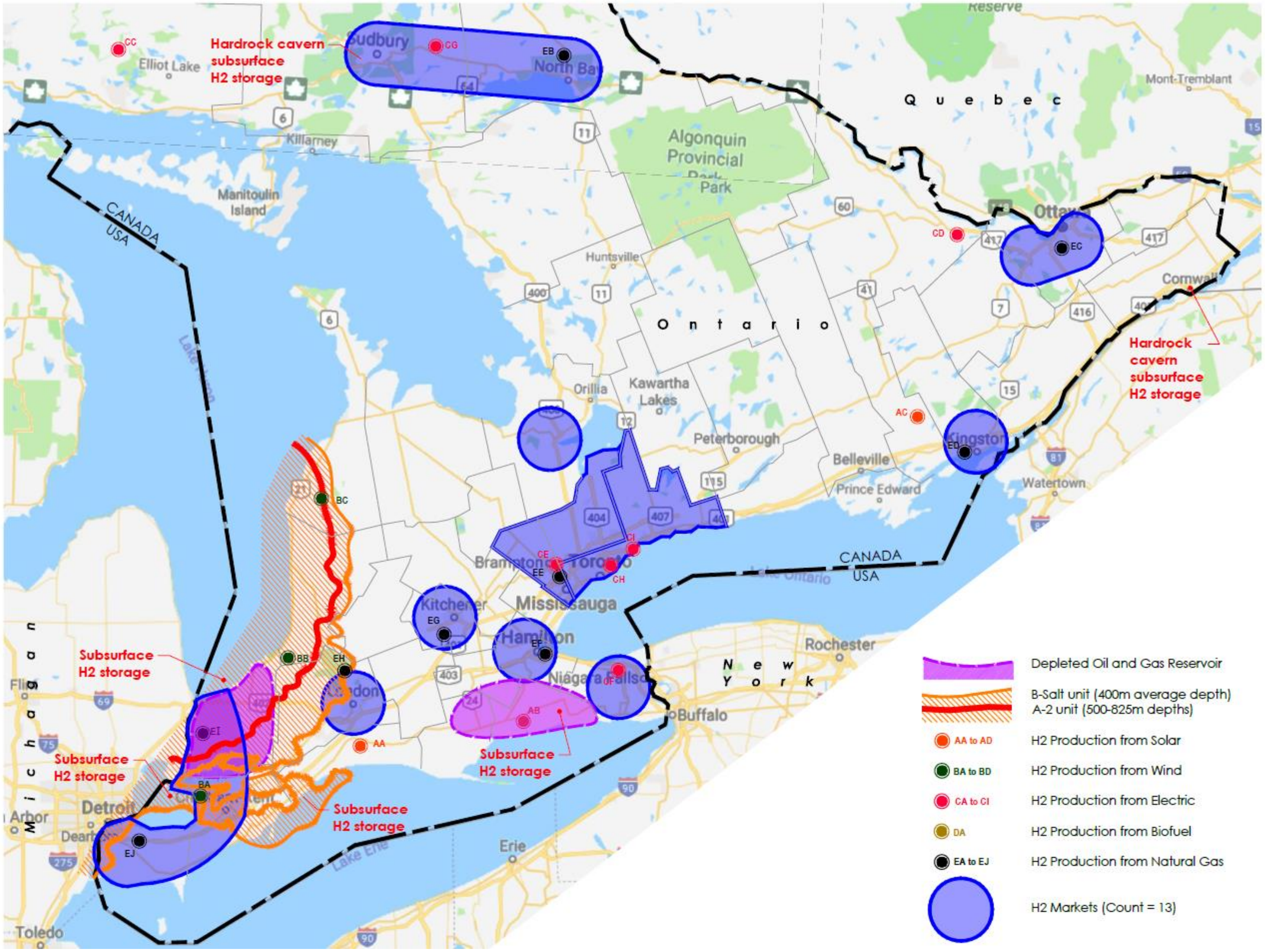


Figure 59: Prospective Hypothetical Sites for Subsurface Hydrogen Storage (in salt caverns, depleted oil and gas reservoirs, or hard rock caverns)

This proposed siting was developed with an idea in mind: that hydrogen imported or exported across provincial borders in trade with neighbouring jurisdictions would likely benefit from large, seasonal-capacity storage volumes near points of entry. The points of storage were, therefore, as much about transportation along established commodity corridors as favourable geologies. Some of the proposed storage sites align to the border crossings of the conceptual CO_2 pipeline proposed previously, in section 5.3. Conceivably, the corridors identified for CO_2 pipeline routing could also serve to transport hydrogen to and from the province.

7.0 PUTTING THE MAPS TO WORK – ASSESSING THE POTENTIAL FOR COMMERCIAL HUBS DEVELOPMENT

The preceding sections present a range of contextual information, in sequence:

- technologies and systems of carbon capture and utilization applicable to Ontario industries.
- geologies within the province and neighbouring jurisdictions having promising potential for CO_2 storage and permanent sequestration.
- maps of major CO_2-emitting sites.
- conceptual routes for the transport of capture carbon within Ontario and across its borders.
- geologies within the province having potential for temporary, underground storage of hydrogen, as well as systems of surface storage; and
- maps of prospective sites of hydrogen production, based on feedstock type, and hubs of potential market demand in Ontario.

This information has inherent value as primer material for stakeholders seeking to engage in policy dialogue that focuses on the application of CCUS and hydrogen systems to the challenge of decarbonization. It can also be used as a tool of analysis to inform the development of commercial strategy. Suppose, for example, there was need to characterize locations in Ontario where the availability of low-carbon hydrogen and CO_2 co-existed in meaningful volumes. Perhaps these are needed as feedstock for synthetic hydrocarbon fuels having low carbon-intensity, such as sustainable aviation fuel or “green” diesel. Or, perhaps low-carbon hydrogen and captured carbon is needed for synthesis into green ammonia or methanol. The information in this report can be used to scope the market hubs that provide the desired hydrogen, the captured carbon or access to carbon storage needed to develop an economic opportunity.

<u>Example – Hub characterization by hydrogen, CCU and CCS</u>

Consider the top 50 CO_2 emitting sites in the province. The following maps show these sites, zooming into the northern and southern areas for a clearer look. These maps also include the circles representing the collective CO2 emissions from large emitter clusters, as defined earlier in section 5.2. The accompanying tables organize the information visualized in both maps, ordering the top 50 CO_2 emitters from largest (1) to smallest (50).

Table I: Top 50 CO_2 Emitters CCU, CCS, H_2 Assessment: North Region

ID No.	Region	GHG ID No.	Facility Location	City / District / Municipality	CO_2 Tonnes (Fossil Emissions)	CO_2 from Biomass Tonnes (Biogenic Emissions)	CO_2 Emissions Total
30	FN	G10765	End of Highway 652	Cochrane	223,526		
3	N	G10011	105 West Street North	Sault Ste. Marie	4,309,457		
32	N	G10093	1 Station Road	Espanola	221,612	761,597	
34	N	G10165	505 Archer's Drive	Kirkland Lake	218,607	176,912	
35	N	G11078	18 Rink Street	Copper Cliff	190,666		
36	N	G10025	2001 Neebing Avenue	Thunder Bay	169,335	1,107,542	
43	N	G11496	5967 Highway 11/71 PO Box 5	Emo	134,276		
45	N	G10043	17 Highway 17 Highway East	Blind River	129,069		
48	N	G10398	2 Longyear Drive	Falconbridge	123,889		
49	N	G10077	175 Industrial Road	Copper Cliff	119,885		
					5,840,320	**2,046,051**	**7,886,371**

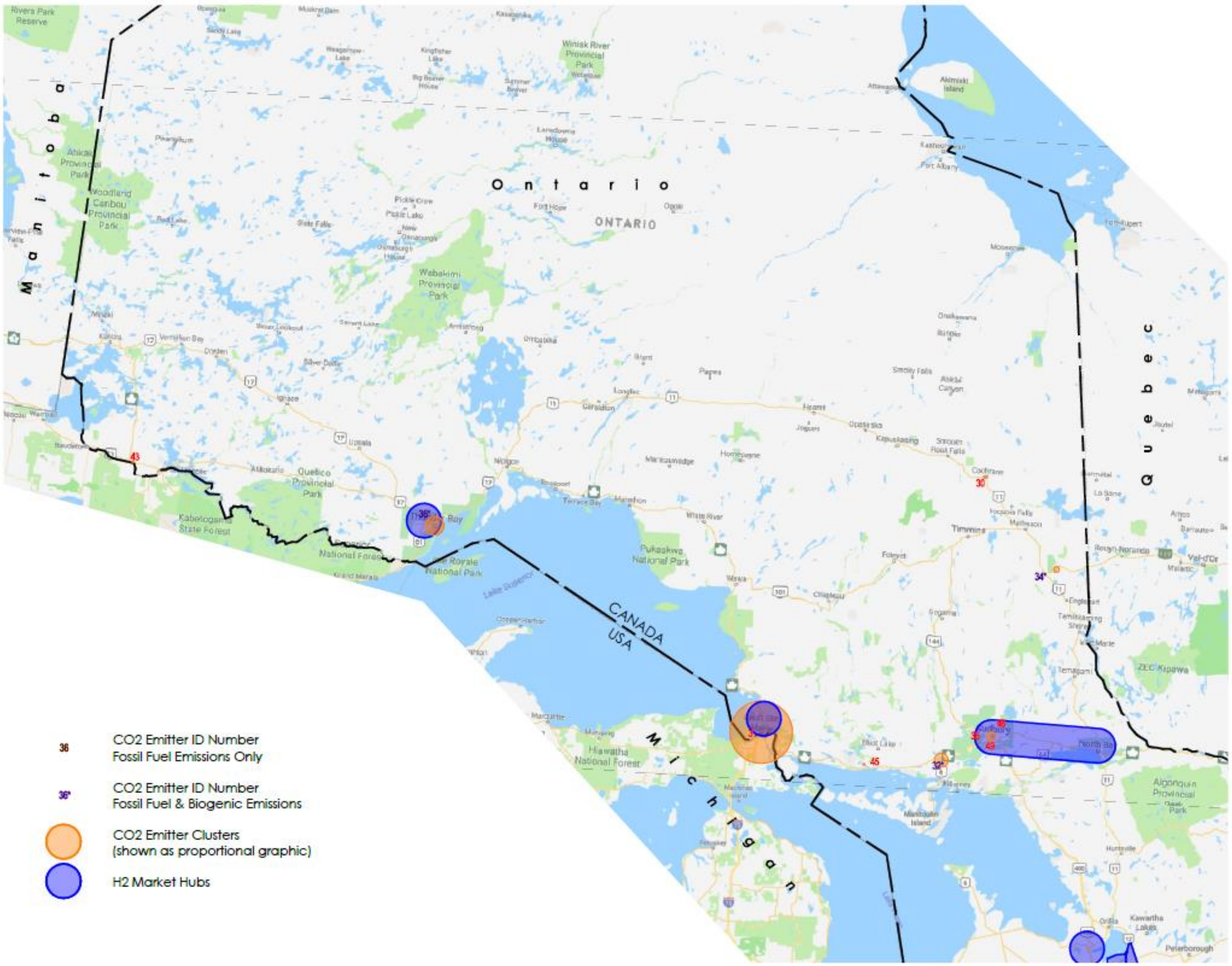


Figure 60: Hydrogen Market Hubs and CCUS Intersections: Northern Ontario

Table J: Top 50 CO_2 Emitters CCU, CCS, H_2 Assessment: South Region

ID No.	Region	GHG ID No.	Facility Location	City / District / Municipality	CO_2 Tonnes (Fossil Emissions)	CO_2 from Biomass Tonnes (Biogenic Emissions)	CO_2 Emissions Total
1	W	G10091	1330 Burlington Street East	Hamilton	4,781,149		
2	W	G10646	7870 Sixth Line South	Halton Hills	4,779,686		
4	W	G10276	2330 Regional #3 Road	Haldimand County	3,831,148		
5	W	G10255	602 Christina Street South	Sarnia	1,811,257		
7	W	G10199	225 Concession 2	Nanticoke	1,179,224		
9	W	G10256	1475 Vidal Street South	Sarnia	968,800		
10	W	G10208	785 Petrolia Line	Corunna	952,441		
11	W	G10407	140 Bickford Line	Courtright	917,077		
13	W	G10254	1900 River Road	Sarnia	756,591		
14	W	G10253	150 St. Clair Parkway	Corunna	722,289		
15	W	G10283	161 Bickford Line	Courtright	666,084		
17	W	G10360	150 St. Clair Parkway	Corunna	531,546		
18	W	G10274	585 Water Street South	St. Marys	517,352		
19	W	G10050	600 Highway #5 Highway West	Dundas	511,532		
21	W	G10051	374681 Oxford County 6 Road	Ingersoll	434,784		
23	W	G10251	602 Christina Street South	Sarnia	425,225		
24	W	G10114	3551551 35th Line	Woodstock	378,526		
26	W	G11793	1265 Vidal Street	Sarnia	301,907		
27	W	G10554	790 Petrolia Line	Corunna	299,962		
28	W	G10250	602 Christina Street South	Sarnia	273,235		
29	W	G10275	386 Wilcox Street	Hamilton	248,501		
31	W	G10133	755 Parkdale Avenue North	Hamilton	222,165		
37	W	G10622	90 Allanburg Road	Thorold	165,719		
38	W	G10559	535 Rokeby Line	Mooretown	156,899		
39	W	G10252	1182 Plank Road	Sarnia	152,665		
40	W	G11743	477 Oil Springs Line	Courtright	149,397		
41	W	G10482	1555 Elm Street	Port Colborne	141,748		
42	W	G10075	275 Bloomfield Rad	Chatham	139,037		
46	W	G10057	1100 Green Valley Road	London	125,672		
8	CW	G10192	2391 Lakeshore Road	Mississauga	1,012,155		
20	CW	G10191	385 Southdown Road	Mississauga	447,820		
25	CW	G10469	8600 Goreway Drive	Brampton	369,655		
6	CE	G10273	410 Bowmanville Aveenue	Bowmanville	1,519,655		
22	CE	G10413	470 Unwin Avenue	Toronto	433,338		
33	CE	G10319	1550 Wentworth Street	Whitby	219,559		
44	CE	G10459	0 120 Pearl Street	Toronto	132,831		
12	E	G10171	6501 Highway 33 Highway West	Bath	775,633		
16	E	G10223	1370 49 Highway South	Picton	533,531		
47	E	G10614	1040 County Rd 17 Road	L'Orignal	124,936		
50	E	G10177	0 7263 33 Highway	Greater Napanee	116,957		
					32,227,688	**0**	**32,227,688**

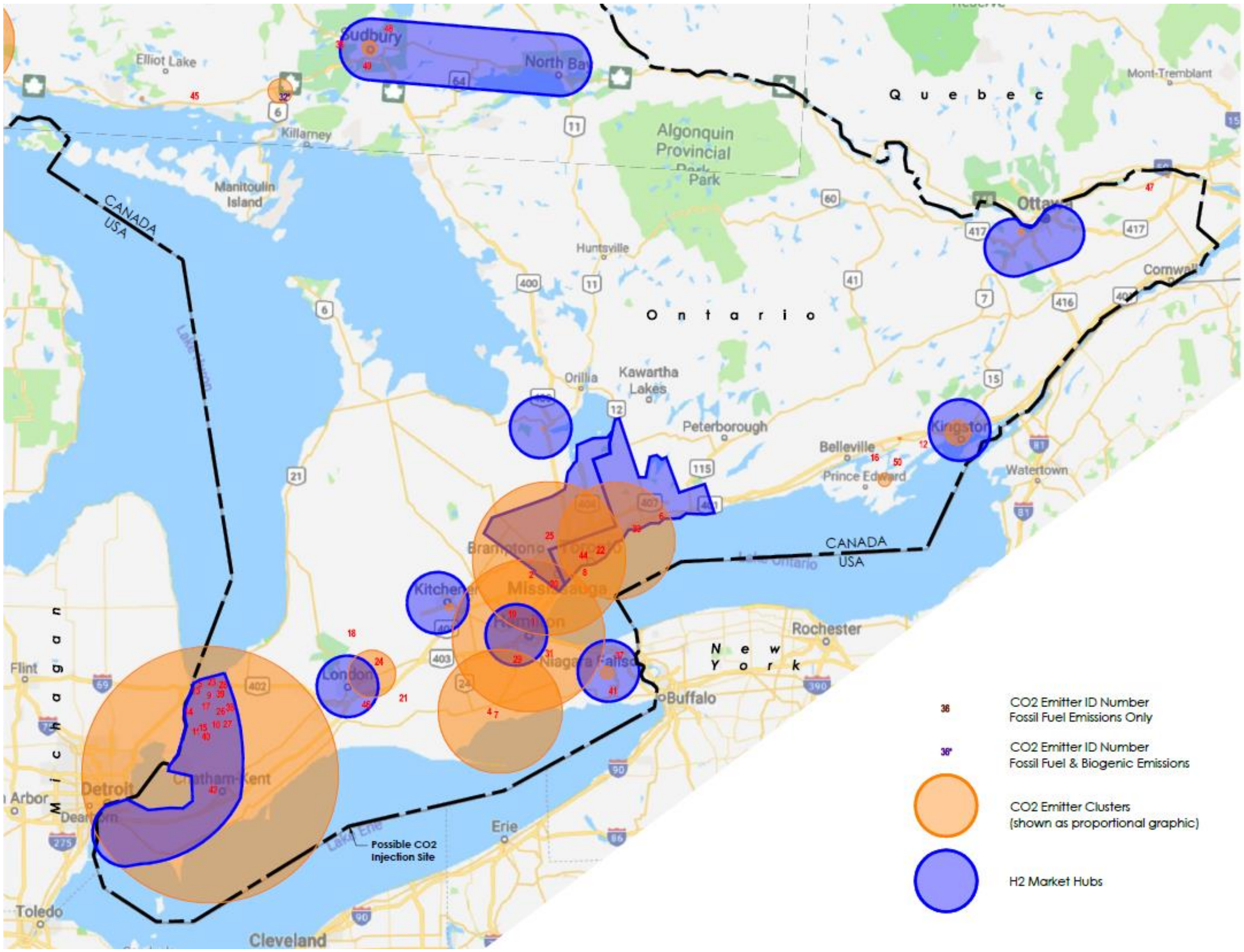


Figure 61: Hydrogen Market Hubs and CCUS Intersections: Southern Ontario

Now consider how each of these CO_2-emitting sites satisfies the following characteristics:

- Proximity to an identified hydrogen market hub. If close enough, then there is potential for synthetic hydrocarbon production. Let this condition be labelled *CCU*, since the captured carbon will be used.
- Proximity to CO_2 pipeline, railway or marine port for conveyance to a storage resource for sequestration. Let this condition be labelled *CCS*, indicating storage service availability.
- Proximity to both hydrogen hubs and CCS service, for the most opportunity and flexibility with hydrogen and CO_2 feedstock, labelled as *CCU+CCS*.
- If there is no practical proximity to a hydrogen hub nor to CO_2 pipeline, the site can be considered *stranded*, and labelled accordingly.

The following two tables detail this assessment; the first table focuses on the top 50 emitters (representing 81 per cent of the total sector GHG emissions), and identified in the mapping. The second table extends the assessment to include the emmiters identified from 51- 267, and are considered secondary emitters. These secondary emitters are not included in the mapping.

The assessment is referenced to the hydrogen hubs identified and mapped in the preceding section of this report. Within each hub, the co-located emitters. intersecting infrastructure and new hydrogen production sites (also identified in the preceding section). The map below shows these data layers.

Table K: Prospective H_2 / CCU / CCS Market Hubs and Top 50 CO_2 Emitters

Market Location	City	Region	CO_2 Emitter Intersection	Infrastructure Intersections								New H_2 Production	Hub Type
				A	B	C	D	E	F	G	H		
1	Thunder Bay	North	36	✓	✓	✓	✓	✓	✓	✓	✓	EA, DA	H_2/CCU
2	Sault Ste. Marie	North	3	✓	✓		✓	✓	✓	✓	✓	BD	H_2/CCU/CCS
3	North Bay / Sudbury	North	35, 48, 49	✓	✓			✓		✓	✓	EB, CG	H_2/ CCU
4	Hamilton	West	1, 19, 29, 31	✓	✓	✓		✓		✓	✓	EF, EG, AB	H_2/CCU/CCS
5	Niagara, Welland, St. Catharines	West	37, 41	✓	✓			✓	✓	✓	✓	CF	H_2/CCU
6	Kitchener / Waterloo	West	-	✓	✓	✓		✓		✓	✓	EG	H_2/CCU/CCS
7	London	West	18, 21, 24, 46	✓	✓	✓		✓		✓	✓	EH, AA, BB	H_2/CCU/CCS
8	Windsor / Sarnia	West	5, 9, 10, 11, 13, 14, 15, 17, 23, 26, 27, 28, 38, 39, 40, 42	✓	✓	✓	✓	✓	✓	✓	✓	EJ, EI, BA	H_2/CCU/CCS
9	Peel, York	Central West	2, 20, 25	✓	✓	✓	✓	✓	✓	✓	✓	EE, CE	H_2/CCU/CCS
10	Barrie	Central West	-	✓				✓		✓		-	H_2/CCU/CCS
11	Toronto, Durham	Central East	6, 8, 22, 33, 44	✓	✓	✓	✓	✓	✓	✓	✓	EE, CE	H_2/CCU/CCS
12	Kingston	East	12	✓	✓			✓	✓	✓	✓	AC, ED	H_2/CCU/CCS
13	Ottawa / Kanata	East	-	✓	✓	✓		✓	✓	✓	✓	EC, CD	H_2/CCU/CCS
Stranded		Far North	30									CA	CCU/CCS
Stranded		North	32, 34, 43, 45									CB, CC, AD	CCU/CCS
Stranded		West	4, 7									BC	CCU/CCS
Stranded		Central West	-										CCU/CCS
Stranded		East	16, 47, 50										CCU/CCS

A = road
E = grid electric
B = rail
F = point electric
C = airport
G = grid natural gas
D = marine
H = point hydrogen (prospective)

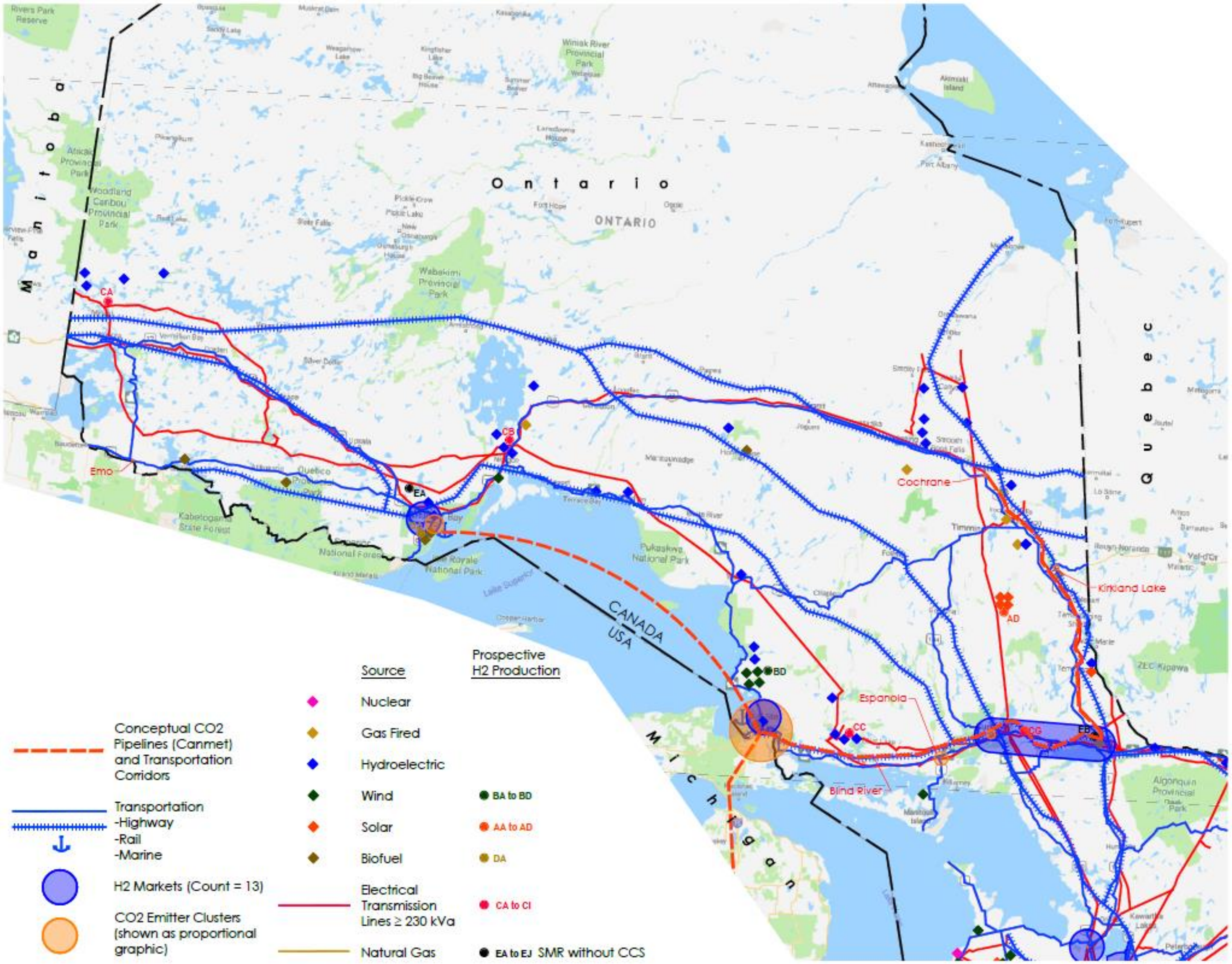


Figure 62: Hydrogen Market Hubs, CO_2 Emitters, Infrastructure and Transportation Corridors: Northern Ontario

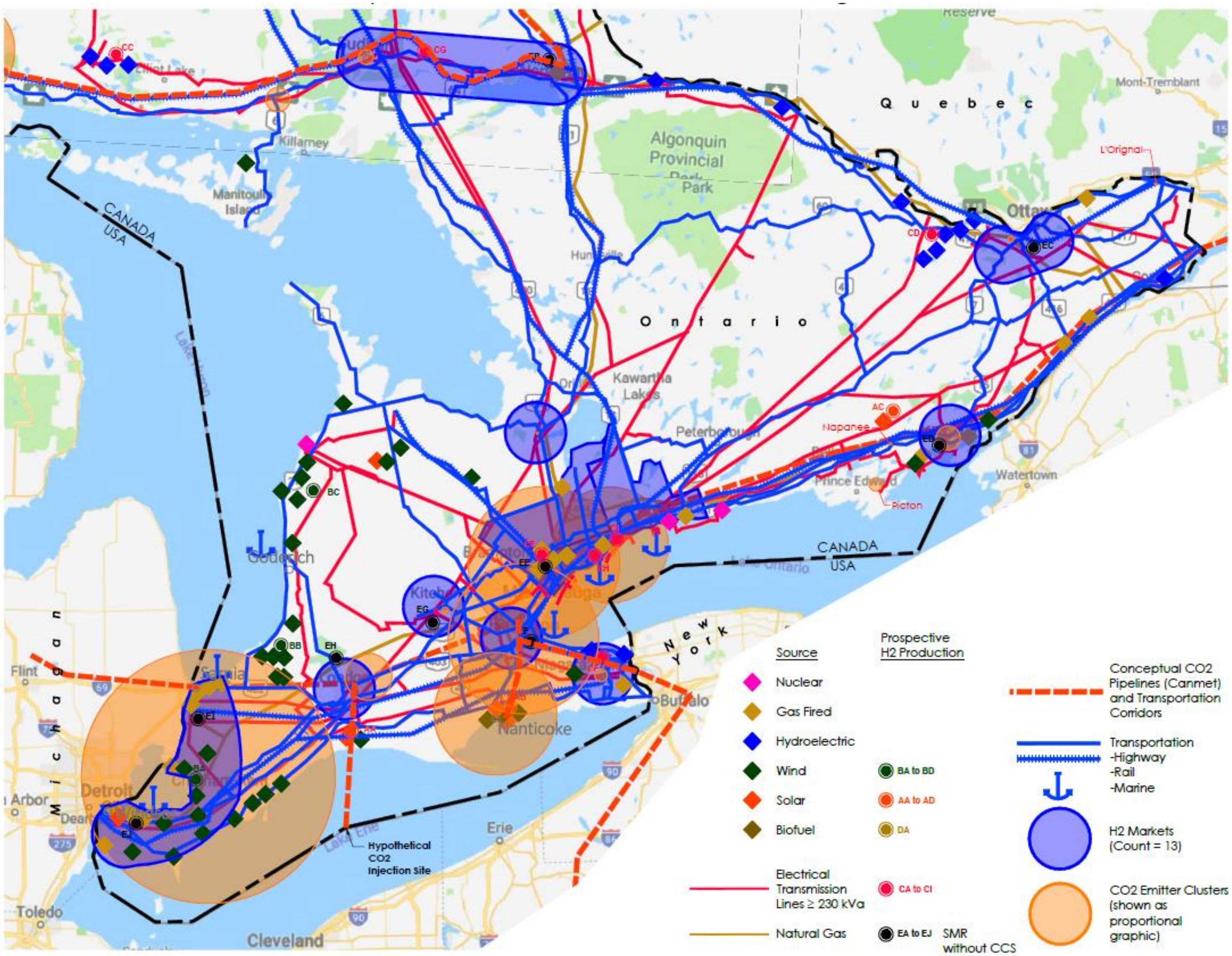


Figure 63: Hydrogen Market Hubs, CO_2 Emitters, Infrastructure and Transportation Corridors: Southern Ontario

Table L: Prospective H_2 / CCU / CCS Market Hubs and Secondary CO_2 Emitters (51-267)

Market Location	City	Region	CO_2 Emitter Intersection	Infrastructure Intersections								New H_2 Production	Hub Type
				A	B	C	D	E	F	G	H		
1	Thunder Bay	North	114, 172, 215	✓	✓	✓	✓	✓	✓	✓	✓	EA, DA	H_2/CCU
2	Sault Ste. Marie	North	68, 99	✓	✓		✓	✓	✓	✓	✓	BD	H_2/CCU/CCS
3	North Bay / Sudbury	North	75, 123, 166, 218, 229, 240, 241	✓	✓			✓		✓	✓	EB, CG	H_2/ CCU
4	Hamilton	West	91, 104, 119, 121, 127, 228, 142, 148, 151, 152, 178, 187, 188, 196, 217, 223, 246	✓	✓	✓		✓		✓	✓	EF, EG, AB	H_2/CCU/CCS
5	Niagara, Welland, St. Catharines	West	115, 146, 160, 162, 169, 182, 184, 198, 220, 221	✓	✓			✓	✓	✓	✓	CF	H_2/CCU
6	Kitchener / Waterloo	West	56, 96, 101, 113, 195, 197, 227, 237, 264	✓	✓	✓		✓		✓	✓	EG	H_2/CCU/CCS
7	London	West	66, 90, 94, 98, 106, 108, 129, 150, 200, 210, 242, 249, 257	✓	✓	✓		✓		✓	✓	EH, AA, BB	H_2/CCU/CCS
8	Windsor / Sarnia	West	51,58, 67, 72, 73, 76, 81, 93, 102, 110, 117, 124, 128, 132, 133, 135, 136, 140, 155, 158, 159, 161, 163, 167, 171, 179, 180, 183, 186, 190, 199, 201, 204, 206, 213, 222, 224, 230, 231, 238	✓	✓	✓	✓	✓	✓	✓	✓	EJ, EI, BA	H_2/CCU/CCS
9	Peel, York	Central West	62, 64, 71, 80, 84, 85, 107, 126, 209, 212, 233, 239, 243, 256, 258, 259, 267	✓	✓	✓	✓	✓	✓	✓	✓	EE, CE	H_2/CCU/CCS
10	Barrie	Central West	83 164	✓				✓		✓		-	H_2/CCU/CCS
11	Toronto, Durham	Central East	53, 55, 63, 65, 69, 74, 77, 79, 82, 87, 89, 95, 109, 120, 137, 154, 156, 165, 181, 191, 211, 216, 225, 251, 252, 254, 255, 266	✓	✓	✓	✓	✓	✓	✓	✓	EE, CE	H_2/CCU/CCS
12	Kingston	East	59, 92, 122, 170, 177, 262, 263	✓	✓			✓	✓	✓	✓	AC, ED	H_2/CCU/CCS
13	Ottawa / Kanata	East	111, 118, 153, 176, 207, 214, 248, 260	✓	✓	✓		✓	✓	✓	✓	EC, CD	H_2/CCU/CCS

Market Location	City	Region	CO_2 Emitter Intersection	Infrastructure Intersections								New H_2 Production	Hub Type
				A	B	C	D	E	F	G	H		
Stranded		Far North	88, 105, 112, 116, 125, 143, 149, 157, 174, 193, 194, 203, 208, 244, 245, 247, 250									CA	CCU/CCS
Stranded		North	52, 75, 78, 145, 189, 219, 234, 265									CB, CC, AD	CCU/CCS
Stranded		West	60, 70, 104, 130, 131, 134, 138, 139, 141, 173, 175, 205									BC	CCU/CCS
Stranded		Central West	232										CCU/CCS
Stranded		East	54, 57, 61, 86, 97, 100, 103, 144, 147, 168, 185, 192, 202, 226, 235, 236, 253, 261										CCU/CCS

As shown the tables above, each of the 18 hydrogen markets assessed is characterized according to its type as having high potential for low-carbon hydrogen production, or for carbon capture and use, or for carbon capture and storage, or as a mix of the three. These characteristics are dependent on the presence of a major, capturable source of CO_2 emissions, the presence of hydrogen production potential and the presence of supporting infrastructure.

The next table summarizes the hubs by types, organized by the 13 geographically-identified hydrogen market hubs, as well as the 5 representative hubs and the stranded CO_2 emitters, and incorporates a sum of the annual CO_2 within each hub in tonnes and as a percentage of the total emissions inventory. Were this an exercise to assess the potential for synthetic hydrocarbon fuel or chemical production, the hydrogen volume requirements could be readily assessed for the available carbon in each of the markets. This kind of analysis could help to prioritize the energy feedstock capacity, which could inform energy system planning. Since this analysis is constrained to existing infrastructure, its relevance would be expected to hold for the next 10-15 years, into the 2035 timeframe.

Table M: Prospective H_2 / CCU / CCS Market Hubs Summary

Market Location	City	Region	Top 50 CO_2 Emitter Intersection	CO_2 tpy	%	Secondary 217 CO_2 Emmitter Intersection	CO_2 tpy	%	$\sum CO_2$ tpy	$\sum$ %	New H2 Production	Hub Type
1	Thunder Bay	North	36	1,276,877	2.57%	114, 172, 215	67,457	0.14%	1,344,334	2.70%	EA, DA	H_2 / CCU
2	Sault Ste. Marie	North	3	4,309,457	8.66%	68, 99	181,402	0.36%	4,490,859	9.02%	BD	H_2 / CCU / CCS
3	North Bay / Sudbury	North	35, 48, 49	434,439	0.87%	75, 123, 166, 218, 229, 240, 241	168,112	0.34%	602,552	1.21%	EB, CG	H_2 / CCU
4	Hamilton	West	1, 19, 29, 31	5,764,707	11.58%	91, 104, 119, 121, 127, 142, 148, 151, 152, 178, 187, 188, 196, 217, 223, 228, 246	391,964	0.79%	6,156,671	12.37%	EF, EG, AB	H_2 / CCU / CCS
5	Niagara, Welland, St. Catharines	West	37, 41	307,467	0.62%	115, 146, 160, 162, 169, 182, 184, 198, 220, 221	197,988	0.40%	505,455	1.02%	CF	H_2 / CCU / CCS
6	Kitchener / Waterloo	West	-		0.00%	56, 96, 101, 113, 195, 197, 227, 237, 264	274,188	0.55%	274,188	0.55%	EG	H_2 / CCU / CCS
7	London	West	18, 21, 24, 46	1,470,527	2.95%	66, 90, 94, 98, 106, 108, 129, 150, 200, 210, 242, 249, 257	440,360	0.88%	1,910,887	3.84%	EH, AA, BB	H_2 / CCU / CCS
8	Windsor / Sarnia / Chatham	West	5, 9, 10, 11, 13, 14, 15, 17, 23, 26, 27, 28, 38, 39, 40, 42	9,224,413	18.53%	51, 58, 67, 72, 73, 76, 81, 93, 102, 110, 117, 124, 128, 132, 133, 135, 136, 140, 155, 158, 159, 161, 163, 167, 171, 179, 180, 183, 186, 190, 199, 201, 204, 206, 213, 222, 224, 230,	1,300,824	2.61%	10,525,237	21.15%	EJ, EI, BA	H_2 / CCU / CCS
9	Peel, York	Central West	2, 20, 25	5,597,161	11.24%	62, 64, 71, 80, 84, 85, 107, 126, 209, 212, 233, 239, 243, 256, 258, 259, 267	616,109	1.24%	6,213,270	12.48%	EE, CE	H_2 / CCU / CCS
10	Barrie	Central West	-		0.00%	83, 164	85,871	0.17%	85,871	0.17%	-	H_2 / CCU / CCS
11	Toronto, Durham	Central East	6, 8, 22, 33, 44	3,317,538	6.66%	53, 55, 63, 65, 69, 74, 77, 79, 82, 87, 89, 95, 109, 120, 137, 154, 156, 165, 181, 191, 211, 216, 225, 251, 252, 254, 255, 266	1,417,769	2.85%	4,735,307	9.51%	EE, CE	H_2 / CCU / CCS
12	Kingston	East	12	775,633	1.56%	59, 92, 122, 170, 177, 262, 263	212,388	0.43%	988,021	1.98%	AC, ED	H_2 / CCU / CCS
13	Ottawa / Kanata	East	-		0.00%	111, 118, 153, 176, 207, 214, 248, 260	224,715	0.45%	224,715	0.45%	EC, CD	H_2 / CCU / CCS
Stranded	Cochrane	Far North	30	223,526	0.45%			0.00%	223,526	0.45%		CCU / CCS
Stranded		Far North			0.00%	88, 105, 112, 116, 125, 143, 149, 157, 174, 193, 194, 203, 208, 244, 245, 247, 250	857,803	1.72%	857,803	1.72%	CA	CCU / CCS
Stranded	Espanola	North	32	983,209	1.98%			0.00%	983,209	1.98%		CCU / CCS
Stranded	Kirkland Lake	North	34	395,519	0.79%			0.00%	395,519	0.79%		CCU / CCS
Stranded	Emo	North	43	134,276	0.27%			0.00%	134,276	0.27%		CCU / CCS
Stranded	Blind River	North	45	129,069	0.26%			0.00%	129,069	0.26%		CCU / CCS
Stranded		North			0.00%	52, 75, 78, 145, 189, 219, 234, 265	2,257,379	4.54%	2,257,379	4.54%	CB, CC, AD	CCU / CCS
Stranded	Nanticoke	West	4, 7	5,010,372	10.07%			0.00%	5,010,372	10.07%		CCU / CCS
Stranded		West			0.00%	60, 70, 104, 130, 131, 134, 138, 139, 141, 173, 175, 205	407,755	0.82%	407,755	0.82%	BC	CCU / CCS
Stranded		Central West			0.00%	232	11,896	0.02%	11,896	0.02%		CCU / CCS
Stranded	Picton	East	16	533,531	1.07%			0.00%	533,531	1.07%		CCU / CCS
Stranded	L'Orignal	East	47	124,936	0.25%			0.00%	124,936	0.25%		CCU / CCS
Stranded	Napanee	East	50	116,957	0.23%			0.00%	116,957	0.23%		CCU / CCS
Stranded		East			0.00%	54, 57, 61, 86, 97, 100, 103, 144, 147, 168, 185, 192, 202, 226, 235, 236, 253, 261	656,931	1.32%	656,931	1.32%		CCU / CCS

Far North = 18 @ 2.17% North = 29 @ 20.76% West =127@49.81% Central West = 23 @ 12.67% Central East = 33 @ 9.51% East = 37 @ 5.31%

8.0 OBSERVATIONS AND RECOMMENDATIONS

The review of literature conducted for this study on the systems of carbon capture revealed no major gaps in the readiness of technology. Of the types of CO_2 capture researched, most are represented in systems that are currently in commercial use around the world, including in Canada. Even the emerging platforms, such as Direct Air Capture, are composed of technologies that are in common use. However, these systems are only coupled with permanent CO_2 sequestration or utilization solutions in some rare instances, reflecting a lack of sufficient economic motivation. That circumstance is beginning to change in Canada, as an increasing price on the emissions of GHGs to the atmosphere is now being applied through government policy, and that brings some significant issues into focus in Ontario.

Issue #1 – Carbon sequestration potential in Ontario urgently requires validation.

This report offers some informed speculation about where CO_2 injection into different geological formations has promise for permanent storage. However, direct geological survey work is needed to assess and validate this potential. Such field work and laboratory analysis requires financial investment. Government and industry could consider pooling resources to spread the risk, by developing a program of accelerated testing.

Issue #2 – Engagement of Indigenous communities requires guidance and support.

Development of CCUS systems in Ontario will partly be functions of geology and of geography. Access to ideal CO_2 injection and storage sites, access to energy to power CCUS operations, and access to routes by which to transport CO_2 are all land-based determinants. As noted in section 4.4 of this report, Indigenous communities and Treaty Lands are represented in all part of the province. Hence, many successful CCUS projects are likely to be Indigenous-led enterprises or arise from meaningful consultation and partnership with host communities. To facilitate the required engagement and capacity-building, the establishment of an Indigenous Desk is advised, having a mandate to guide, inform and support CCUS project proponents and impacted communities alike, focusing on the determinants of well-being priorities of Indigenous communities and lands. The scope could include hydrogen subsurface storage developments, as well. A goal of the Indigenous Desk would be to help advance CCUS and hydrogen developments in Ontario consistent with the principles of Reconciliation.

Issue #3 – Coordination and capacity-building among major emitters would help.

The private companies representing Ontario's largest CO_2-emitting facilities are few. The decisions of perhaps only one or two dozen companies to proceed with CO_2 injection and storage projects will likely define the direction of the market for CCS services, including pipeline transport. Moreover, the facilities implicated are often among the hardest-to-abate sources of emissions. It seems reasonable that the shared interests of this group of companies be a focal point around which to organize. Coordination within this major emitters, hard-to-abate assembly of companies could facilitate knowledge sharing, project risk mitigation and, importantly, engagement with government.

Issue #4 – Interjurisdictional cooperation would benefit Ontario.

The geological formations ideal for CO_2 sequestration are contiguous across Ontario's borders with neighbouring jurisdictions, including in the U.S. Viewed as a shared, natural resource, the injection if CO_2 into geological repositories could be jointly managed by governments having jurisdiction. An analogy to this would be International Joint Commission, which coordinates stewardship efforts of the Great Lakes between the U.S. and Canada as a shared ecosystem. As a starting point, it is recommended that Ontario engage with the Midwest Regional Carbon Sequestration Partnership and explore the potential for collaboration in mutual interest.

Issue #5 – Technoeconomic analysis is required for long-term planning of CCUS systems.

Ontario stakeholders should avail themselves of the services and programs operated by CanmetENERGY under the National CCUS Assessment Framework. Open source data and tools of analysis are available to private sector organizations seeking cost-optimal solutions to various scenarios of multi-modal CO_2 transport and storage, to better inform strategy development and investment decisions. Research programs are also building a valuable knowledge base on carbon capture systems and subsurface storage of both CO_2 and hydrogen. It is recommended that this resource of information and analysis be widely promoted among Ontario stakeholders, to maximize knowledge transfer.

Issue #6 – A comprehensive CCUS strategy and legal framework needs articulation.

As discussed in section 2.2.3 of this report, several years ago the Government of Alberta undertook to clarify the legal obligations relating to underground CO_2 injection and storage, as well as legacy management of sequestered carbon, among key stakeholders. This effectively addressed the question, "Who owns the pore space?", and legitimized geological sequestration of CO_2 in Alberta. A similar legal assessment is recommended for Ontario to provide industry and government clarity on roles and responsibilities for injection site operations, for post-operation stewardship over the long-term (including transfers of liability of injected CO_2 between proponent and Crown) and for accounting and verification of avoided GHG emissions.

Issue #7 – CCUS initiatives in Ontario may be accelerated with the support of targeted government policy.

The scale of the capital and operating expenditures associated with establishing CCUS potentials within Ontario are significant. As projects, such initiatives may only become investible once the marginal price on carbon rises sufficiently high. In the meantime, targeted intervention by government through supportive policy and programming can help to accelerate industry-led efforts to build Ontario's CCUS capacity while maintaining competitiveness (especially among GHG emissions-intensive, trade-exposed industries).

The successful development of market hubs wherein the scaling up of robust systems of low-carbon hydrogen production and use can occur depends in part on geography. In this report, prospective hub locations were presented for analysis, in which proximity of feedstock for supply and offtake demand are critical factors. This is because hydrogen costs accumulate rapidly with distance transported, compared to most liquid commodities. To build a low-carbon hydrogen sector in Ontario that directly benefits all Ontarians, it is recommended to start with hubs of hydrogen activity having high commercial potential. The creation of value in free market exchange of hydrogen will drive its adoption and yield improving scales of economy over time. Part of the value potential of these hubs, as centres of sustainable development, is in the opportunity to match flows of hydrogen with CO_2 to support the production of low-carbon fuels and chemicals, which is a form of carbon capture and utilization. As the sector matures, trade in hydrogen between the market hubs and across provincial borders is expected, which may be facilitated and enhanced by developing subsurface storage caverns with capacity for buffering large volumes of hydrogen – either for import or export. Looking ahead, some gaps are apparent that should be addressed.

<u>Issue #8 – Commercial assessment of hydrogen market hubs</u>.

This report provides a speculative forecast of where hydrogen hubs make sense from a geographic perspective, based on population density, supporting infrastructure and feedstock availability. However, the economic performance of a hub is the greater determinant of sustained growth and resilience. As demonstrated in H2GO Canada's companion study, *Estimating Low-Carbon Hydrogen Supply and Demand in Ontario to 2050, Based on an Assessment of Effective Value Chain Development*, it is possible to model the economic performance of prospective hydrogen market. This characterization should be applied to each of the hydrogen hubs identified in this report <u>in consultation with key stakeholders</u> in that market. This will help to convene the motivated parties and mobilize private sector investment, as well as identify the best ways in which government can support hydrogen hub development (including CCUS services, where applicable). Some other areas in Ontario should also be considered priorities for assessment, such as in Bruce County and Nanticoke. While these are not identified as market hubs in the analysis herein, due to an absence of population-based demand for hydrogen, the productive and consumptive potentials of key sites in these areas could be instrumental in anchoring regional markets.

<u>Issue #9 – Remote applications of hydrogen to support off-diesel communities</u>.

Notwithstanding the importance of hydrogen hub development in densely populated markets, remote communities deserve attention, too. Often remote and grid-isolated communities have few options to transition from their reliance on diesel-fueled power generation. The versatility of hydrogen can offer a compelling pathway for decarbonization of not only power, but also fuel for space heating and transportation. The small size of these communities creates special challenges to commercial viability, which is why a special assessment of the technical feasibility, economic practicability and social acceptability of hydrogen systems in diesel-dependent communities is recommended.

Issue #10 – Assess conflicting (or synergistic) demands for underground gas storage.

The means of temporary, subsurface storage of hydrogen addressed in this report could also be applicable to other forms of gaseous storage. One possible example is compressed air energy storage systems. Interest in ideal geologies and sites for cavern storage could lead to competitive prospecting, or it could be a source of mutual benefit for different parties. A panel to assess the range of established and emerging interests in underground fluid storage opportunities in Ontario is recommended.

9.0 CONCLUDING REMARKS

This report is intended to provoke and inform a broad discussion on the subject of CCUS and hydrogen storage in Ontario. It is not the first word on the topic nor will it be the last. The report also leaves a number of important issues unaddressed that deserve further exploration. In part, this reflects a need to practically restrict the scope of the literature review and analyses carried out by the study team, but also because many questions simply have no simple answers.

For example, the published costs of carbon capture and storage are often extrapolated from only a few data sources. The fragmented nature of the available data and its industry-specificity often makes meaningful comparisons difficult. The true costs of integrating carbon capture to existing industrial facilities in Ontario are likely to be as unique as the sites themselves. Support for CCUS must therefore consider site-specific technologies and processes that enable a host facility to further excel in quality, productivity and competitiveness while achieving deep levels of decarbonization. Cost factors may also change significantly as Ontario's north further opens to economic development, supported by new infrastructure and transportation corridors.

Moreover, the transport of captured CO_2 and its injection underground raise a number of environmental, social and logistical questions not addressed herein, such as induced seismicity, effects of CO_2 leakage on ecosystems, how communities may respond to the prospect of hosting CO_2 storage, and the durability of institutions assigned responsibility for long-term stewardship of stored carbon to name just a few. While geology may favour sequestration outside of Ontario's jurisdiction, will the public and other governments permit cross-border transportation corridors to be developed? Even if confidence in transport and sequestration operations is secured, do railways have capacity to accommodate a scale-up in the transport of CO_2, and can existing pipelines in Ontario be used to transport it in a supercritical fluid state?

The fact is that CO_2 transport, injection and sequestration has been happening for many years in other parts of Canada and in the U.S. provides some assurance that the challenges faced in Ontario may be met through the application of experience and knowhow that is commercially available. As well, the International Energy Agency considers CCUS instrumental to achieving net-zero GHG emissions by mid-century (and net-negative growth beyond through direct air-capture solutions).

Nonetheless, CCUS breaks new ground in Ontario from a technological and a policy perspective. The answers to some questions will only be discovered by doing. Fortunately, Ontario also has a deep well of expertise to draw from in academia, industry and the Ontario Geological Survey. The Government of Ontario also has experience in helping Canada to fulfil international and binational commitments on trade and the environment. One example is the *Canada-Ontario Agreement on Great Lakes Water Quality and Ecosystem Health*, which contributes to Canada's commitments under the *Canada-U.S. Great Lakes Water Quality Agreement*.

The tools and the talent are in place to act on the recommendations in this report. Leadership is now needed to convene the stakeholders and make a plan.

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APPENDIX 1 LIST OF ONTARIO INDIGENOUS COMMUNITIES (FIRST NATIONS, MÉTIS)

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
1	Aamjiwnaang (Chippewas of Sarnia)	172	Southern First Nations Secretariat	Union of Ontario Indians	Upper Canada Treaties Area 2
2	Alderville	160	Ogemawahj Tribal Council	Union of Ontario Indians	Williams Treaty
3	Animakee Wa Zhing 37 formerly known as Northwest Angle 37	152	Anishinaabeg of Kabapikotawangag Resource Council	Grand Council of Treaty 3	Treaty 3
4	Anishnaabeg of Naongashiing	125	Anishinaabeg of Kabapikotawangag Resource Council	Grand Council of Treaty 3	Treaty 3
5	Apitipi Anicinapek formerly known as Wahgoshig	233	Wabun Tribal Council	Nishnawbe-Aski Nation	Treaty 9
6	Ardoch Algonquin		Independent	Independent	Upper Canada Treaties Area 1
7	Aroland	242	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
8	Atikokan		MNO Atikokan Metis Council		
9	Atikameksheng Anishnawbek formerly known as Whitefish Lake	224	North Shore Tribal Council	Union of Ontario Indians	Robinson-Huron Treaty
10	Attawapiskat	143	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
11	Aundek Omni Kaning (Sucker Creek)	180	United Chiefs & Councils of Manitoulin Island	Union of Ontario Indians	Manitoulin Island Treaty
12	Barrie		MNO Barrie South - Simcoe Metis Council		
13	Batchewana	198	North Shore Tribal Council	Association of Iroquois and Allied Indians	Robinson-Huron Treaty
14	Bearskin Lake	207	Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
15	Beausoleil (Christian Island)	141	Ogemawahj Tribal Council	Union of Ontario Indians	Upper Canada Treaties Area 2
16	Beaverhouse		Wabun Tribal Council	Nishnawbe-Aski Nation	Treaty 9
17	Big Grassy	124	Anishinaabeg of Kabapikotawangag Resource Council	Grand Council of Treaty 3	Treaty 3

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
	Biigtigong Nishnaabeg also referred to as Pic River	192	Unaffiliated	Union of Ontario Indians	Robinson-Superior Treaty
19	Bingwi Neyaashi Anishinaabek formerly known as Sand Point	196	Independent	Union of Ontario Indians	Robinson-Superior Treaty
20	Brampton		MNO Credit River Metis Council		
21	Brantford		MNO Clear Waters Metis Council		
22	Brunswick House	228	Wabun Tribal Council	Nishnawbe-Aski Nation	Treaty 9
23	Caldwell	165	Southern First Nations Secretariat	Association of Iroquois and Allied Indians	Upper Canada Treaties Area 2
24	Cat Lake	216	Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
25	Chapleau Cree	221	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
26	Chapleau Ojibway	229	Wabun Tribal Council	Nishnawbe-Aski Nation	Treaty 9
27	Chapleau		MNO Chapleau Metis Council		
28	Chippewas of the Thames	166	Southern First Nations Secretariat	Union of Ontario Indians	Upper Canada Treaties Area 2
29	Cochrane		MNO Northern Lights Metis Council		
30	Constance Lake	182	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
31	Couchiching (Fort Frances)	126	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
32	Curve Lake	161	Unaffiliated	Union of Ontario Indians	Upper Canada Treaties Area 1
33	Deer Lake First Nation	237	Keewaytinook Okimakanak	Nishnawbe-Aski Nation	Treaty 9
34	Dokis (Waabnoong Bemjwang)	218	Waabnoong Bemjiwang Association of First Nations	Union of Ontario Indians	Robinson-Huron Treaty
35	Dryden		MNO Northwest Metis Council		
36	Eabametoong (Fort Hope)	183	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
37	Eagle Lake	148	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
38	Flying Post	227	Independent	Nishnawbe-Aski Nation	Treaty 9
39	Fort Albany	142	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
40	Fort Frances		MNO Sunset Country Metis Council		
41	Fort Severn	215	Keewaytinook Okimakanak	Nishnawbe-Aski Nation	Treaty 9
42	Fort William	187	Nokiiwin Tribal Council	Union of Ontario Indians	Robinson-Superior Treaty
43	Garden River	199	North Shore Tribal Council	Union of Ontario Indians	Robinson-Huron Treaty
44	Georgina Island (Chippewas of Georgina)	138	Ogemawahj Tribal Council	Union of Ontario Indians	Williams Treaty
45	Geraldton		MNO Greenstone Metis Council		
46	Ginoogaming	185	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
47	Golden Lake (Algonquins of Pikwakanagan)	163	Unaffiliated	Union of Ontario Indians	Upper Canada Treaties Area 1
48	Grassy Narrows	149	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
49	Gravenhurst		MNO Moon River Metis Council		
50	Gull Bay (Kiashke Zaaging Anishinaabek)	188	Nokiiwin Tribal Council	Union of Ontario Indians	Robinson-Superior Treaty
51	Haileybury		MNO Temiskaming Metis Council		
52	Henvey Inlet	231	Waabnoong Bemjiwang Association of First Nations	Union of Ontario Indians	Williams Treaty
53	Hiawatha	162	Unaffiliated	Association of Iroquois and Allied Indians	Upper Canada Treaties Area 1
54	Hornepayne		Matawa First Nations	Nishnawbe-Aski Nation	Unceded
55	Kasabonika Lake	210	Shibogama First Nations Council	Nishnawbe-Aski Nation	Treaty 9
56	Kashechewan		Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
57	Kee-Way-Win	325	Keewaytinook Okimakanak	Nishnawbe-Aski Nation	Treaty 9
58	Kenora		MNO Kenora Metis Council		
59	Kettle and Stony Point	171	Southern First Nations Secretariat	Union of Ontario Indians	Upper Canada Treaties Area 2
60	Kingfisher Lake	212	Shibogama First Nations Council	Nishnawbe-Aski Nation	Treaty 9
61	Kitchener		MNO Grand River Metis Council		

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
62	Kitchenuhmaykoosib Inninuwug	209	Independent First Nations Alliance	Independent	Treaty 9
63	Koocheching		Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
64	Lac Des Milles Lac	189	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
65	Lac La Croix	127	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
66	Lac Seul	205	Independent First Nations Alliance	Grand Council of Treaty 3	Treaty 3
67	Lake Nipigon Ojibway (Animbiigoo Zaagi'igan)	194	Nokiiwin Tribal Council	Independent	Robinson-Superior Treaty
68	London		MNO Thames Bluewater Metis Council		
69	Long Lake 58	184	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
70	Magnetawan	174	Waabnoong Bemjiwang Association of First Nations	Union of Ontario Indians	Williams Treaty
71	Martin Falls (Ogoki Post)	186	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
72	Matachewan	219	Wabun Tribal Council	Nishnawbe-Aski Nation	Treaty 9
73	Mattagami	226	Wabun Tribal Council	Nishnawbe-Aski Nation	Treaty 9
74	Mattawa		MNO Mattawa Metis Council		
75	McDowell Lake	326	Keewaytinook Okimakanak	Nishnawbe-Aski Nation	Treaty 9
76	M'Chigeeng	181	United Chiefs & Councils of Manitoulin Island	Union of Ontario Indians	Manitoulin Island Treaty
77	Michipicoten	225	Unaffiliated	Union of Ontario Indians	Robinson-Superior Treaty
78	Midland		MNO Georgian Bay Metis Council		
79	Missanabie Cree Nation	223	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
80	Mississauga #8	200	North Shore Tribal Council	Union of Ontario Indians	Robinson-Huron Treaty
81	Mitaanjigamiing First Nation formerly known as Stanjikoming	133	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
82	Mohawks of Akwesasne	159	Independent	Independent	Upper Canada Treaties Area 1

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
83	Mohawks of the Bay of Quinte-Tyendinaga	164	Unaffiliated	Association of Iroquois and Allied Indians	Upper Canada Treaties Area 1
84	Moose Cree	144	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
85	Moose Deer Point	135	Ogemawahj Tribal Council	Union of Ontario Indians	Williams Treaty
86	Moravian of the Thames	167	Southern First Nations Secretariat	Association of Iroquois and Allied Indians	Upper Canada Treaties Area 2
87	Munsee Delaware	168	Southern First Nations Secretariat	Union of Ontario Indians	Upper Canada Treaties Area 2
88	Muskrat Dam Lake First Nation	213	Independent First Nations Alliance	Nishnawbe-Aski Nation	Treaty 9
89	Naicatchewenin	128	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
90	Naotkamegwanning Whitefish Bay	158	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
91	Napanee		MNO Highland Waters Metis Council		
92	Nawash	122	Unaffiliated	Independent	Upper Canada Treaties Area 2
93	Neskantaga (Lansdowne House)	239	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
94	Netmizaaggamig Nishnaabeg (Pic Mobert)	195	Unaffiliated	Union of Ontario Indians	Robinson-Superior Treaty
95	New Credit (Mississaugas)	120	Unaffiliated	Association of Iroquois and Allied Indians	Upper Canada Treaties Area 2
96	Nibinamik (Summer Beaver)	241	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9
97	Nigigoonsiminikaaning (Red Gut FN)	129	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
98	Niisaachewan Anishinaabe (Dalles) formerly known as Ochiichagwe'Babigo'Ining Ojibway	147	Unaffiliated	Grand Council of Treaty 3	Treaty 3
99	Nipissing	220	Waabnoong Bemjiwang Association of First Nations	Union of Ontario Indians	Robinson-Huron Treaty
100	North Bay		MNO North Bay Metis Council		

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
101	North Caribou (Weagamow/Round Lake)	204	Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
102	North Channel		MNO North Channel Metis Council		
103	North Spirit Lake	238	Keewaytinook Okimakanak	Nishnawbe-Aski Nation	Treaty 9
104	Northwest Angle No. 33	151	Anishinaabeg of Kabapikotawangag Resource Council	Grand Council of Treaty 3	Treaty 3
105	Saugeen (Savant Lake)	258	Windigo First Nations Council	Grand Council of Treaty 3	Treaty 3
106	Ojibways of Onigaming	131	Anishinaabeg of Kabapikotawangag Resource Council	Grand Council of Treaty 3	Treaty 3
107	Oneida	169 246	Southern First Nations Secretariat	Association of Iroquois and Allied Indians	Upper Canada Treaties Area 2
108	Oshawa		MNO Oshawa and Durham Regio Metis Council		
109	Osnaburgh (Mishkeegogamang)	203	Independent First Nations Alliance	Nishnawbe-Aski Nation	Treaty 9
110	Ottawa		MNO Ottawa Region Metis Council		
111	Owen Sound		MNO Great Lakes Metis Council		
112	Pays Plat	191	Unaffiliated	Union of Ontario Indians	Robinson-Superior Treaty
113	Peterborough		MNO Peterborough and District Wapiti Metis Council		
114	Pikangikum	208	Independent First Nations Alliance	Nishnawbe-Aski Nation	Treaty 9
115	Poplar Hill	236	Keewaytinook Okimakanak	Nishnawbe-Aski Nation	Treaty 9
116	Rainy River	130	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
117	Rama (Chippewas of Mnjikaning)	139	Ogemawahj Tribal Council	Independent	Williams Treaty

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
118	Red Rock	193	Unaffiliated	Union of Ontario Indians	Robinson-Superior Treaty
119	Rocky Bay (Biinjitiwaabik Zaaging Anishinaabek)	197	Nokiiwin Tribal Council	Union of Ontario Indians	Robinson-Superior Treaty
120	Sachigo Lake	214	Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
121	Sagamok Anishnawbek	179	North Shore Tribal Council	Union of Ontario Indians	Robinson-Huron Treaty
122	Sandy Lake	211	Independent	Nishnawbe-Aski Nation	Treaty 9
123	Saugeen Nation (Chippewas of Saugeen)	123	Unaffiliated	Independent	Upper Canada Treaties Area 2
124	Sault Ste. Marie		MNO Historic Sault Ste. Marie Metis Council		
125	Scugog Island	140	Ogemawahj Tribal Council	Union of Ontario Indians	Upper Canada Treaties Area 1
126	Seine River	132	Pwi-Di-Goo-Zing-Ne-Yaa-Zhing Advisory Services	Grand Council of Treaty 3	Treaty 3
127	Serpent River	201	North Shore Tribal Council	Union of Ontario Indians	Robinson-Huron Treaty
128	Shawanaga	137	Independent	Independent	Robinson Huron 1850
129	Sheguiandah	176	United Chiefs & Council Of Manitoulin Island	Union of Ontario Indians	Manitoulin Island Treaty
130	Sheshegwaning	178	United Chiefs & Council Of Manitoulin Island	Union of Ontario Indians	Manitoulin Island Treaty
131	Shoal Lake No 39 (Iskatewizaagegan)	154	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
132	Shoal Lake No. 40	155	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
133	Six Nations	121	Unaffiliated	Independent	Upper Canada Treaties Area 2
134	Six Nations of the Grand River Ohsweken	121	Unaffiliated	Independent	Upper Canada Treaties Area 2
135	Slate Falls (Bamaji Lake)	259	Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
136	Sudbury		MNO Sudbury Metis Council		

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
137	Taykwa Tagamou Nation (New Post)	145	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
138	Temagami	222	Unaffiliated	Independent	Robinson-Huron Treaty
139	Terrace Bay		MNO Superior North Shore Metis Council		
140	Thessalon	202	North Shore Tribal Council	Union of Ontario Indians	Robinson-Huron Treaty
141	Thorold		MNO Niagara Region Metis Council		
142	Thunder Bay		MNO Thunder Bay and District Metis Council		
143	Timmins		MNO Timmins Metis Council		
144	Toronto		MNO Toronto & York Region Metis Council		
145	Wabaseemoong (Whitedog)	150	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
146	Wabauskang	156	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
147	Wabigoon Lake	157	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
148	Wahnapitae	232	Waabnoong Bemjiwang Association of First Nations	Union of Ontario Indians	Robinson-Huron Treaty
149	Wahta Mohawks	134	Unaffiliated	Association of Iroquois and Allied Indians	Williams Treaty
150	Walpole Island (Bkejwanong First Nation)	170	Unaffiliated	Independent	Upper Canada Treaties Area 2
151	Wapekeka (Angling Lake)	206	Shibogama First Nations Council	Nishnawbe-Aski Nation	Treaty 9
152	Wasauksing	136	Unaffiliated	Union of Ontario Indians	Williams Treaty
153	Washagamis Bay (Obashkaandagaang)	235	Bimose Tribal Council	Grand Council of Treaty 3	Treaty 3
154	Wauzhushk Onigum (Rat Portage)	153	Anishinaabeg of Kabapikotawangag Resource Council, www.akrc.on.ca	Grand Council of Treaty 3	Treaty 3
155	Wawakapewin (Long Dog)	234	Shibogama First Nations Council	Nishnawbe-Aski Nation	Treaty 9
156	Webequie	240	Matawa First Nations	Nishnawbe-Aski Nation	Treaty 9

	Community	Band #	Tribal Council	Primary Tribal Organization	Treaty
157	Weenusk (Peawanuck)	146	Mushkegowuk Council	Nishnawbe-Aski Nation	Treaty 9
158	Whitefish River	230	United Chiefs & Council Of Manitoulin Island	Union of Ontario Indians	Robinson-Huron Treaty
159	Whitesand	190	Independent First Nations Alliance	Nishnawbe-Aski Nation	Treaty 9
160	Whitewater Lake		Windigo First Nations Council	Nishnawbe-Aski Nation	Treaty 9
161	Wikwemikong	175	Unaffiliated	Union of Ontario Indians	Manitoulin Island Treaty
162	Wunnumin Lake	217	Shibogama First Nations Council	Nishnawbe-Aski Nation	Treaty 9
163	Zhiibaahaasing (Cockburn Island)	173	United Chiefs & Council Of Manitoulin Island	Union of Ontario Indians	Manitoulin Island Treaty

Source: K-net First Nation Communities [48], Métis Nation of Ontario [49]

APPENDIX 2 LIST OF ONTARIO FIRST NATIONS ENERGY PROJECTS

#	Year	Project Name	Project Type	MW	Indigenous Community	Partner
1	1992	Wawatay Station Hydroelectric Project (Black River)	Hydro	13.5	Ojibways of the Pic River First Nation	Innergex Developed with Regional Power, the Band holds a minority position
2	1997	Shekak-Nagagami hydro-electric project	Hydro	19	Constance Lake First Nation	Algonquin Power (Nagagami) Limited Partnership between Constance Lake First Nation and subsidiaries of Brookfield Renewable
3	1997	Kasabonika Lake FN	Wind	30	Kasabonika Lake FN	---
4	2001	Twin Falls Hydroelectric Project (Kagiano)	Hydro	5	Ojibways of the Pic River First Nation	Kagiano Power Corporation
5	2003	Five Nation Energy	Transmission	270-kilometres of 115 kV high voltage line	Five Nation Energy	---
6	2008	Umbata Falls Hydroelectric Project	Hydro	23	Ojibways of the Pic River First Nation	Umbata Falls LP Innergex (49)
7	2009	Lac Seul Hydro Obishikokaang Waasiganikewigamig -	Hydro	12	Lac Seul First Nation	Ontario Power Generation Inc.
8	2011	Greenwich Wind farm	Wind	98.9	Fort William (Ojibways of Onigaming First Nation)	Enbridge and RES Canada
9	2012	Mother Earth Renewable Energy Wind Project	Wind	4	M'Chigeeng First Nation	3G Energy
10	2012	Bruce to Milton transmission	Transmission	180-kilometer, 500 kV line	Saugeen Ojibway First Nations	HydroOne
11	2013	Olympiad Renewable Energy Centre	Bioenergy	7.5	Ojibways of the Pic River First Nation	Rentech Inc.
12	2013	White Otter Falls	Hydro	5.5	Chapleau Cree First Nation	Nipiy-Wof Hydrokap L.P. Hydromega Services Inc

#	Year	Project Name	Project Type	MW	Indigenous Community	Partner
13	2013	Camp Three Rapids	Hydro	5.5	Chapleau Ojibwe First Nation	Amik-Ctr Hydrokap L.P. Hydromega Services Inc
14	2013	Big Beaver Falls	Hydro	5.5	Brunswick House First Nation	Amik-Bbf Hydrokap L.P. Hydromega Services Inc
15	2013	Alderville First Nation Solar PV Groundmount Project	Solar	5.7	Alderville First Nation	Alderville Solar Limited Partnership
16	2013	Summerhaven Project	Wind	40	Six Nation of the Grand River	NextEra Energy
17	2014	Rainy River (3 projects one site - Morley, Dave Rampel, Vanzwolf)	Solar	25	Rainy River First Nation	Rainy River First Nations Solar LP Connor Clark & Lunn Infrastructure partner
18	2014	Pic River Hydro Project (High Falls and Manitou Falls)	Hydro	6	Ojibways of the Pic River First Nation	---
19	2014	Fort William First Nation Solar Park	Solar	10	Fort William (Ojibways of Onigaming First Nation)	SkyPower Canadian Solar
20	2014	McLean's Mountain	Wind	60	Mnidoo Mnising (6 First Nations)	McLean's Mountain Wind Limited Partnership Northland Power Inc.
21	2014	Dufferin Wind Power	wind	91.4	Six Nation of the Grand River	Dufferin Wind Power Inc.
22	2014	South Kent	Wind	270	Walpole Island First Nation	Samsung / Pattern Energy
23	2014	Port Dover / Nanticoke	Wind	104.4	Six Nation of the Grand River	Capital Power (PDN) L.P.
24	2014	Norfolk Bloomsburg	Solar	10	Six Nation of the Grand River	Sune Norfolk Bloomsburg LP SunEdison
25	2014	Grand Renewable Energy Park	Wind	149	Six Nation of the Grand River	Samsung / Pattern Energy
26	2015	Lower Mattagami River Project (Little Long, Smoky Falls, Harmon, and Kipling)	Hydro	450	Moose Cree First Nation	Ontario Power Generation Inc.

#	Year	Project Name	Project Type	MW	Indigenous Community	Partner
27	2015	Martin Four Phase III Solar Power Projects "Cochrane Solar"	Solar	120	Taykwa Tagamou Nation and Wahgoshig First Nation	Northland Power Inc.
28	2015	Bow Lake Wind	Wind	58.3	Batchewana First Nation (Chinodin Chigumi Nodin Kitagan)	Nodin Kitagan Limited Partnership BluEarth
29	2015	Goulais Wind Project	Wind	25.3	Batchewana First Nation of Ojibways	Chi-Wiikwedong LP Capstone
30	2015	Okikendawt Hydroelectric Project	Hydro	10	Dokis First Nation	Okikendawt Hydro L.P. Hydromega Services Inc
31	2015	Rooftop Solar (13)	Solar	1.8	Shawanaga First Nation	Strathcona Energy Group (SEG)
32	2015	Adelaide (Suncor)	Wind	40	Aamjiwnaang First Nation	Suncor Adelaide Wind Limited Partnership
33	2015	Welland Ridge Road	Solar	10	Six Nation of the Grand River	Sune Welland Ridge LP SunEdison
34	2015	Grand Renewable Energy Park	Solar	100	Six Nation of the Grand River	Samsung C&T, Conner Clark & Lunn Infrastructure, and Six Nations.
35	2015	BGI Roof-Top Solar	Solar	300	Six Nation of the Grand River	Brant Renewable Energy, County of Brant (10%)
36	2016	Namewaminikan Waterpower Project (Twin Falls (4.4 MW) and Long Rapids (5.6 MW)	Hydro	10	• Bingwi Neyaashi Anishinaabek, • Animbiigoo Zaagi'igan Anishinaabek • Biinjitiwaabik Zaaging Anishinaabek	Namewaminikan Hydro Inc. Axor
37	2016	Gitchi Animki Hydroelectric Project (Gitchi Animki Bezhig & Gitchi Animki Niizh) Upper and Lower White River Big Thunder	Hydro	18.9	Pic Mobert First Nation	Pic Mobert Hydro Inc. Regional Power Inc

#	Year	Project Name	Project Type	MW	Indigenous Community	Partner
38	2016	Grand Bend Wind Farm	Wind	100	Giiwedin Noodin FN Energy Corporation (The Aamjiwnaang and Bkejwanong First Nations)	Giiwedin Noodin ("North Wind"), Northlands Power (50%), ecoENERGY
39	2016	Niagara Regional Wind Farm	Wind	230	Six Nation of the Grand River	Boralex, Enercon
40	2016	OBP Oneida Business Park	Solar	500	Six Nation of the Grand River	----
41	2016	Gunn's Hill Wind Farm	Wind	18	Six Nation of the Grand River	Prowind
42	2017	New Post Creek - Peter Sutherland Sr. Generating Station	Hydro	28	Coral Rapids Taykwa Tagamou Nation (TTN)	Ontario Power Generation Inc. (OPG) and Coral Rapids Power LP (wholly owned by Taykwa Tagamou Nation)
43	2017	Northland Power Solar Abitibi	Solar	10	• Taykwa Tagamou Nation • Mattagami First Nation	Northland Power Solar ABitibi L.P.
44	2017	Barlow Solar Energy Centre	Solar	10	Algonquins of Pikwàkanagàn First Nation	EDF EN Canada Development Inc.
45	2019	Niagara Reinforcement Line	Transmission	76-kilometre, double-circuit, 230-kilovolt transmission line	Six Nations and Mississaugas	HydroOne
46	2021	East-West Tie Transmission Project	Transmission	450-kilometer, 230kV line	Multiple 6 Nations	NextBridge, Infrastructure, a partnership with NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure
47	2022	Wataynikaneyap Power	Transmission	KM	Ontario Off-Grid First Nation	Wataynikaneyap Power in partnership with FortisOntario

#	Year	Project Name	Project Type	MW	Indigenous Community	Partner
48	2022	Pickle Lake Transmission Line 300-kilometer, 230kV line	Transmission	KM	Mishkeegogamang and the Ojibway Nation of Saugeen First Nation	Algonquin Power
49	Coming soon	Waasigan Transmission Line	Transmission	230-kV line from Lakhead Transformer to Dryden	TBD	Hydro One
50	Coming soon	Yellow Falls Hydro (Mattagami River)	Hydro	16	• Taykwa Tagamou Nation • Mattagami First Nation	Boralex Inc

Source: Indigenous Clean Energy [40]